Final decision

Victorian electricity distribution network service providers

Distribution determination 2011–2015

October 2010

Contents

Overview

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market.

These are the first electricity distribution determinations made by the AER on the price control regime to apply to the Victorian DNSPs—CitiPower, Powercor, Jemena Electricity Networks (JEN), SP AusNet and United Energy Distribution (United Energy). The previous determination that applied to these DNSPs for the period 2006–10 was made by the Essential Services Commission of Victoria (ESCV). That determination ends on 31 December 2010. The AER's determinations will then take effect on 1 January 2011.

In making its distribution determinations and decisions, the AER has taken into account the Victorian DNSPs' initial and revised regulatory proposals, submissions from interested parties, advice from consultants, relevant information and forecasts and recent decisions of the Australian Competition Tribunal.

The AER's final decision approves higher levels of capital and operating expenditure than are allowed in the current five year regulatory period, and approves higher expenditure than in the draft decision. This is due to additional expenditure needs for replacement of ageing assets and to meet higher customer peak demand. In addition, new safety related obligations have been imposed on the businesses since the draft decision. That said, the AER has not accepted the total level of operating expenditure (opex) and capital expenditure (capex) proposed by the Victorian DNSPs in their revised proposals.

Notwithstanding these additional allowances, the charges allowed by this decision will not change significantly compared to current levels. The result for customers from this decision is that retail price changes for 2011 are expected to range from a reduction of 1.6 per cent (for Citipower) to an increase of 5.1 per cent (SP AusNet). Annual nominal increases in prices averaging between 2–3 percent for the remainder of the period are needed to finance the approved capital program and to meet rising costs.

Assessment approach

A significant aspect of the AER's assessment approach is its review of historical expenditure, to serve as a point of reference in the initial testing of whether the business's proposals of forecast future expenditure are a reasonable estimate of efficient costs.

Previous levels of activity are taken as the starting point to assess future needs, with adjustment to take account of changing circumstances. These changes include an ageing asset base, continuing growth in demand and in numbers of customers, increases in financing costs, wages and material costs, and changes in operational circumstances, such as in relation to safety and other service obligations.

The Victorian electricity distributors have been operating under a framework of incentives to reward efficiency for 10 years and the AER expects that as a result there is a high likelihood that the historic unit cost and business practices are a reliable indication of efficient costs.

The AER has taken into account the operating and capital expenditure 'factors'[1] in determining whether the Victorian DNSPs' total forecast operating and capital expenditure allowances reasonably reflect the operating and capital expenditure criteria.[2] The AER must be satisfied that the proposed expenditure reasonably reflects a realistic demand forecast and cost inputs, and the efficient costs a prudent operator in the circumstances of each DNSP requires, to meet or manage expected demand, comply with regulatory obligations and maintain its network and supply.[3] Importantly, it is the total of the respective forecast expenditures which the AER must be satisfied reasonably reflect the operating and capital expenditure criteria.

Overview of regulatory proposals

Over the past two regulatory control periods (10 years), the Victorian DNSPs’ actual expenditures have been less than those forecast by the firms and less than the allowances set by the ESCV (although this has varied between businesses and regulatory years). The Victorian DNSPs' actual expenditures have generally followed a relatively constant trend, in contrast to the significant increases proposed by the Victorian DNSPs for the forthcoming regulatory control period.

Overall, this trend analysis together with comparative benchmarking of Victorian DNSPs against DNSPs in other jurisdictions suggests that the Victorian DNSPs compare favourably from an efficiency perspective to those in other states. Thus the revealed costs of the Victorian DNSPs are a sound base for determining the starting point for evaluating the efficiency and prudency of their regulatory proposals.

In addition, the Victorian DNSPs have maintained relatively high standards of service, in terms of reliability of supply compared to other jurisdictions. However, evidence has recently emerged which suggests that the policies of some Victorian DNSPs to defer investment may have stretched the capacity of their networks to sustain these levels of service reliability without further investment. This has resulted in the AER approving some increase in augmentation investment in this final decision.

In response to the AER's draft decision, the Victorian DNSPs each proposed increases in expenditure that significantly exceed what they have spent in the current 2006–10 regulatory period, and also exceed what was initially forecast in the current period. Overall, the Victorian DNSPs have proposed increases in capital expenditure of approximately 70 per cent, and increases in operating expenditure of approximately 52 per cent compared to their expected actual spending in the current period.

The combined increases in forecast capex and opex for the Victorian DNSPs in the forthcoming regulatory control period agreed to by the AER amount to $4.7 billion (45 per cent increase) for capex and $2.7 billion (32 per cent increase) for opex compared to current period expenditure. The AER has determined that these amounts

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1 NER, cll. 6.5.6(e) and 6.5.7(e), respectively.
2 NER, cll. 6.5.6(c) and 6.5.7(c), respectively.
3 NER, cll. 6.5.6(a) and 6.5.7(a), respectively.

represent the efficient costs that would be incurred by a prudent operator in the circumstances of the Victorian DNSPs, having regard to changes to their underlying costs, regulatory obligations and the need to meet expected demand. These cost increases were justified following the provision of considerable information, particularly regarding the needs for replacement capex and augmentation, in the revised proposals.

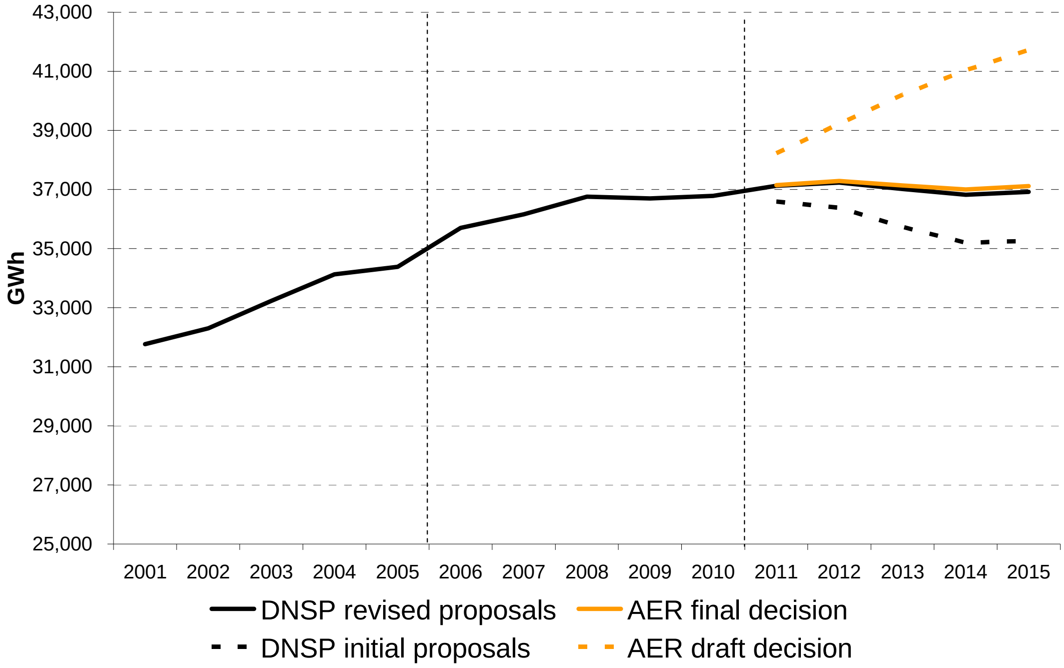
The factors driving this increase include responding to higher peak demand from the use of more energy intensive appliances, such as air conditioners, and the need to continue to replace ageing assets in an environment of increasing input and material cost pressures.

Recent changes in the safety regulatory regime have also resulted in the AER approving higher opex and capex allowances over the forthcoming regulatory control period, relative to past practice and the draft decision.

While it is recognised that climate change may have an impact on future expenditure needs, the effects would develop over a longer term, the AER considers that a specific step-change increase for the forthcoming period is not warranted.

Figure 1 sets out the AER's final decision on forecast energy sales. These forecasts are a key determinant of the DNSPs' expected revenues and required price increases. The chart indicates that the AER has largely agreed with the forecasts proposed by the Victorian DNSPs. It also illustrates that the DNSPs responded to the AER's draft decision through updating their forecasts and moderating the presumed impact of certain energy efficiency measures (including time of use impacts) as well as correcting for an error in the AER's draft decision in relation to population growth adjustments. The AER has also largely accepted the DNSPs' revised customer number and maximum demand forecasts, which are inputs into several elements of the DNSPs' forecast expenditures.

Figure 1 Victorian DNSP historical and forecast energy sales



Capital expenditure

The AER considered the cases put forward by the Victorian DNSPs for changes in requirements that would justify a large increase in capital expenditure over the forthcoming regulatory control period—a combined 70 per cent increase has been proposed or a total of $5.5 billion ($2010) over actual expenditure in the current regulatory period.

The AER considered these proposals for substantial increases in the volume of network build (augmentation and replacement) against actual historical outcomes. The AER also took into account the impact of increases in peak electricity demand.

As foreshadowed in its draft decision, the AER's analysis has found that the costs proposed by the DNSPs are not prudent and efficient. This position is supported by the AER's consultants. The consultants concluded a reasonable estimate of prudent and efficient investment should be relatively consistent with historical trends, with appropriate allowance for increasing needs due to the ageing of the network, further demand growth and other changes in conditions.

Since the draft decision, there have been changes to the safety regime that applies to the Victorian DNSPs. All DNSPs are now required to develop and implement mandatory Energy Safety Management Schemes (ESMS). This has led to a reassessment of replacement expenditure for a number of the DNSPs, which the AER has undertaken in consultation with Energy Safe Victoria (ESV), and a substantial increase in the allowance.

The AER has also reassessed its draft decision in light of the Victorian DNSPs' revised regulatory proposals specifically, the draft decision's findings in relation to customer connections, non-network IT, and particularly reliability related capex.

Changes in these areas have contributed to an increase in the amount of capital expenditure allowed between the draft and final decisions.

Therefore, the AER's final decision allowance considers that there is a need to increase capex, on average, by around 45 per cent compared with actual expenditure in the current regulatory period. Overall, the decision means total capex would be $4.7 billion, around 14 per cent (or $792 million) less than that sought by the DNSPs in their revised regulatory proposals.

Further new obligations and expenditure requirements may eventuate beyond those noted in relation to bushfire mitigation, stemming from recommendations of the Victorian Bushfires Royal Commission (VBRC). These obligations will ultimately be determined by the Victorian Government and will be dealt with under the regulatory framework, including through potential cost pass through events, as they arise.

Figure 2 Victorian DNSP historical and forecast capex comparison ($'m 2010)

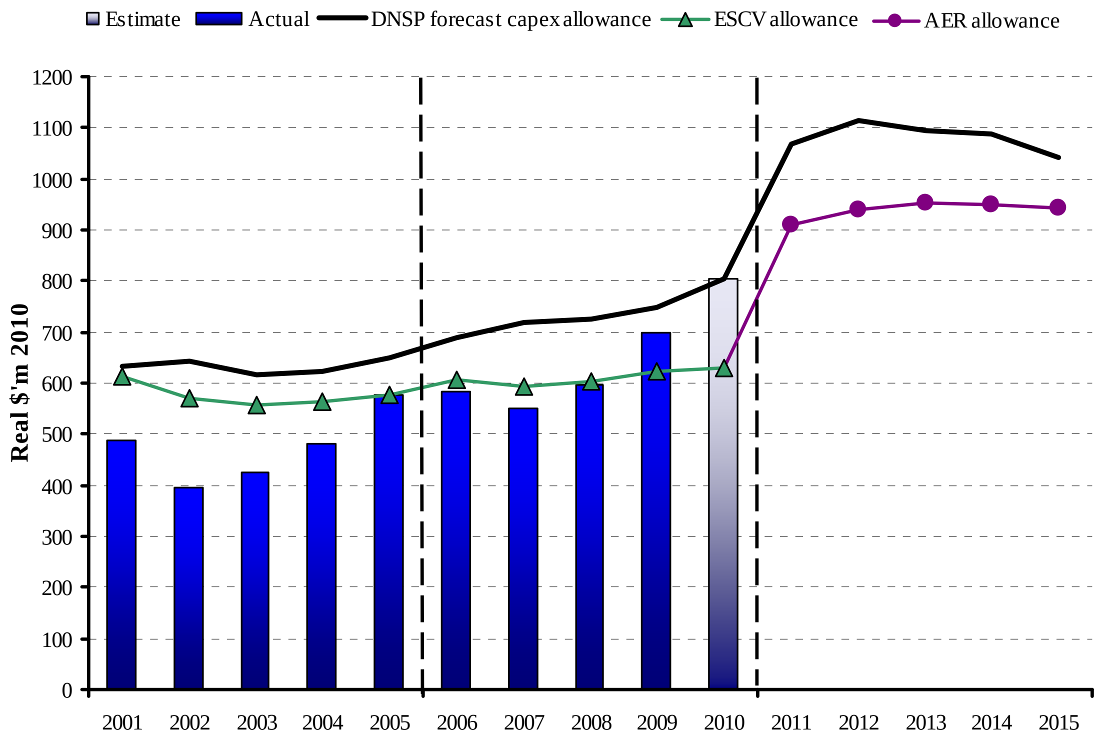


Figure 2 provides an illustration of the Victorian DNSPs' actual and forecast expenditures over the past 10 years as well as their proposed expenditures for the forthcoming regulatory control period. The outcome of the AER's approach in assessing the capex allowance will result in a step increase to the Victorian DNSPs' proposed capex for the forthcoming regulatory control period. A significant component of this initial increase in expenditure is to fund safety related programs which will be closely monitored by the AER and Energy Safe Victoria. Table 2 provides a breakdown of the AER's final decision on capex by expenditure purpose for each DNSP.

Table 2 AER conclusion on DNSP capital expenditure 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Reinforcement	267.6	276.9	98.4	389.3	181.0
Gross demand connections	286.8	672.2	142.3	496.3	249.7
Reliability and quality maintained	163.1	177.1	52.8	202.0	111.0
Environment, safety & legal obligations	34.5	231.3	80.6	220.8	213.4
SCADA & network control	13.9	21.2	2.9	5.0	3.7
Non-network general - IT	48.0	112.3	64.0	147.1	110.9
Non-network general - other	16.5	76.5	32.4	20.8	17.0
Total gross capex	**830.3**	**1567.4**	**473.4**	**1481.2**	**886.8**
Less customer contributions	62.9	243.7	39.5	64.2	134.0
Total net capex	**767.5**	**1323.7**	**433.9**	**1416.9**	**752.8**

Note: Capex in this table includes the AER's final decision on margins, overheads and real cost increases.

Operating expenditure

The AER considered that the underlying level of opex (referred to as base opex) proposed by each Victorian DNSP[4] to be above the efficient level required during the forthcoming regulatory control period. The AER has adjusted the Victorian DNSPs' 'base year level' of opex for a range of factors to ensure that these costs reflect efficient and prudent costs.

The AER has considered the impact on opex from growth in the size of the Victorian DNSPs' distribution networks and customer bases (scale escalation), including any scale efficiencies arising from a larger network over the forthcoming regulatory control period. The AER has allowed an increase in the Victorian DNSPs’ opex allowance in real terms (incorporating changes in real input costs for labour and materials).

The AER has also provided an allowance for costs related to material changes to the Victorian DNSPs' operating environments and changed regulatory obligations, particularly new safety related obligations regarding vegetation management around powerlines.[5] $377.6 million out of a proposed $554.7 for step changes in opex costs represented an efficient increase in the level of operating expenditure for the forthcoming regulatory control period. This includes a total of $206 million for a step change in costs for new electricity safety regulations and a further allowance of $19 million has been provided for new obligations regarding customer communications. Allowances of $41 million and $33 million have been provided for

4 With the exception of United Energy.
5 Electricity Safety (Electric Line Clearance) Regulations 2010 (Vic)

increased information technology and insurance costs respectively while an allowance of $11 million has been provided for demand management activities.

Further, while it is too early to evaluate the precise effect on efficiency from the use of advanced metering infrastructure (AMI), the AER expects that the benefits will develop and will impact on trends in operating and capital costs. The AER will monitor these impacts on costs to ensure that the benefits are returned to customers.

The AER has provided a total opex allowance of $2.7 billion over the forthcoming regulatory control period, an increase of around 32 per cent on actual levels in the current regulatory period. This compares to $3.1 billion of forecast opex sought by the Victorian DNSPs in their revised regulatory proposals.

Figure 3 sets out the Victorian DNSPs' current and forecast opex and the AER's final decision opex allowance.

Figure 3 Victorian DNSP historical and forecast opex comparison ($'m 2010)

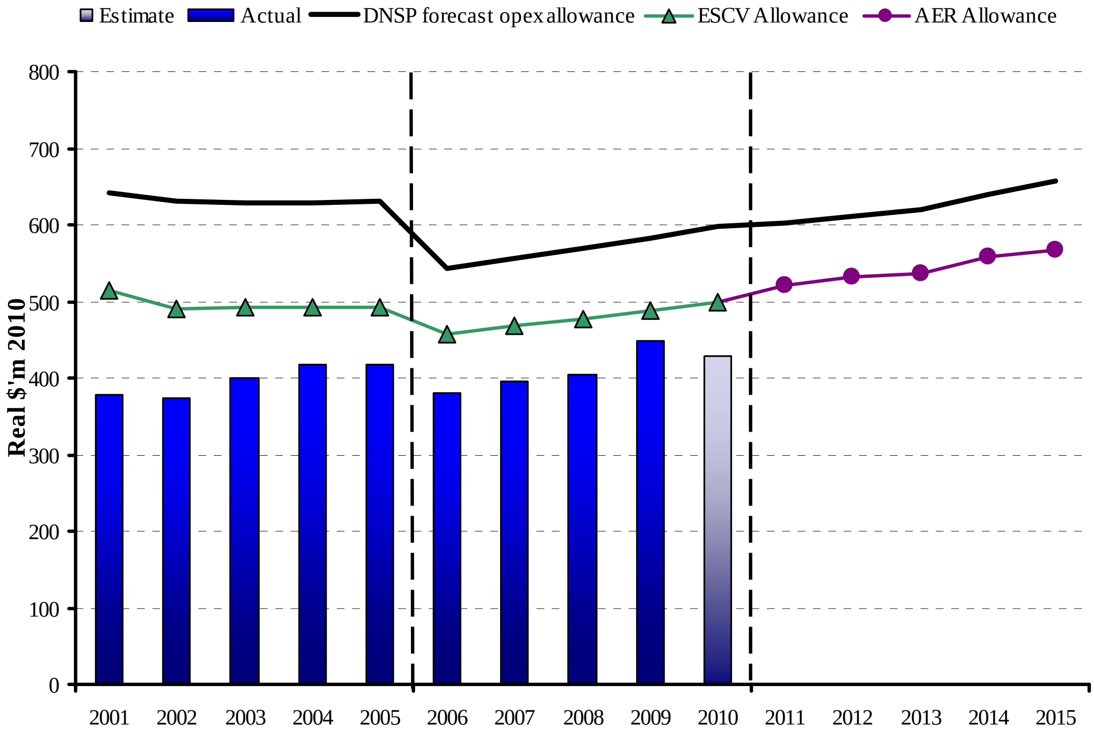


Figure 3 provides an illustration of the Victorian DNSPs' actual and forecast expenditures over the past 10 years as well as their proposed expenditures for the forthcoming regulatory control period.

Cost of capital

The NER provisions require the AER to determine the debt risk premium (DRP), based on an Australian benchmark corporate bond rate with a maturity of 10 years, with a credit rating level as prescribed in the SORI,[6] which is BBB+. Contrasting to the AER's previous determinations, this final decision does not incorporate an

6 In may 2009 the AER released its Final decision on its first electricity industry wide WACC review and accompanying Statement of Regulatory Intent.

examination of the relative merits of Bloomberg and CBASpectrum fair value estimates in setting the DRP, as CBASpectrum not longer publishes relevant information, and the Australian Competition Tribunal recently rejected the approach adopted by the AER to test the merits of Bloomberg and CBASpectrum. In setting the DRP the AER has relied on Bloomberg but also given some weight to the recent issue of a 10 year BBB rated bond by the Australian Pipeline Trust.

The resulting DRP in this final decision is approximately 230 bps higher than that set by the ESCV for the current period, which is reflective of the lingering effects of the global financial crisis on debt markets. This increase is also a key driver for the increase in the cost of capital and required revenues/ prices from 2011 onwards.

The AER has not departed from the MRP value of 6.5 per cent set in the SORI, considering that market conditions have not yet returned to those seen prior to the onset of the GFC.

The cost of capital for the Victorian DNSPs in this decision ranges from 9.40 per cent to 9.95 per cent. This compares with the cost of capital of 8.53 per cent in the current period and this factor alone is a significant driver of increased revenue needs.

Allowance for tax

Following analysis of the payout ratio (a component of gamma), the AER has determined there is persuasive evidence to depart from the SORI gamma value, and determined a value of 0.5 for this final decision.

Monitoring of service levels and cost drivers

The AER intends to establish an outcomes monitoring framework to monitor Victorian DNSPs’ service and financial outcomes against the 2011–15 distribution determinations. The framework is intended to promote transparency and accountability in the DNSPs' investment, expenditure decisions, and the delivery of services to customers. This will result in better information for the AER to assess the DNSPs’ costs and performance for the next Victorian distribution determinations. The areas of monitoring will include:

- service levels delivered by the DNSPs
- actual expenditures compared with the capital and operating expenditure forecasts approved by the AER
- asset condition
- applications of the incentive schemes.

Conclusion

Each of the Victorian DNSPs operate a mature and comparatively reliable network, where asset performance and the operating environment have been relatively stable over past regulatory periods. In looking at the forthcoming period, it is apparent that underlying service performance is being maintained, but some increase in reliability investment is prudent. Further, there is a need to meet new regulatory safety requirements. The result, under a revealed cost approach, is an efficient level of base expenditure consistent with audited actual costs and a path of opex and capex that is expected to grow progressively from current levels to meet expected new needs and higher costs. The decision also incorporates continuing incentives for ongoing operating efficiency as well as maintenance and improvement in service performance where this is valued by customers.

The AER considers that increases in opex and capex are necessary to meet increased costs and new obligations over the next regulatory period as well as higher financing costs (cost of capital). This will result in a range of network price change from an initial increase of 12.8 per cent for SP AusNet to a reduction of 4.0 per cent for Citipower for 2011, and more modest growth in the price of distribution services over the following five years (5.7 to 7.2 per cent) to fund additional expenditure.

Customer impacts

The AER’s final decision will result in an increase in expected revenues across the five DNSPs of 6.0 per cent in 2011 as compared to the preceding year, and further increase of between 5.5 and 8.0 per cent each year thereafter. This steady increase reflects that Victorian DNSPs require additional expenditures to meet capital and operational requirements, as well as a higher cost of capital, when compared to the current regulatory control period. The somewhat larger initial price increases for SP AusNet and JEN also reflect the impact of higher capital expenditure amounts being rolled into their asset bases from 2011, as well as rewards under operational expenditure and service standard incentive mechanisms. For Citipower, network prices will fall in 2011 as its revenues are currently above what the AER has assessed to be the efficient level of costs at the beginning of the new period.

Table 3 Expected revenues ($m, nominal)

	2010	2011	2012	2013	2014	2015
Citipower	213.3	205.8	221.0	235.3	252.8	273.9
Powercor	422.2	440.7	470.0	497.4	529.0	568.8
JEN	168.8	179.8	190.1	199.3	209.1	220.8
SP AusNet	373.9	430.0	458.4	488.4	528.1	575.0
United Energy	291.8	301.9	313.6	324.5	349.5	379.4
Total	**1470.1**	**1558.2**	**1653.2**	**1745.0**	**1868.5**	**2017.8**

As noted in figure one above, growth in energy sales is also expected to moderate during the forthcoming period. This reflects the change to the population growth inputs by the DNSPs, updated economic growth assumptions and a recognition of a modest slowing of total electricity sales growth arising from the use of smart meters and time of use tariffs and energy efficiency measures over the next period. The moderation in sales growth contributes to the need for some increase in prices, particularly in later years, as compared to those set out in the AER's draft decision.

Table 4 Change in network prices (per cent, nominal)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
DNSP revised proposals					
2011	10.0	23.7	19.4	28.3	19.8
Average 2012–15	*6.7*	*3.6*	*5.7*	*4.5*	*6.7*
AER final decision					
2011	–4.0	2.7	7.7	12.8	3.0
Average 2012–15	*7.2*	*6.0*	*5.7*	*7.2*	*6.4*

Table 5 Retail price impacts (per cent, nominal)

	2011	2012 to 2015
DNSP revised proposals		
CitiPower	4.0	2.7
Powercor	9.5	1.4
JEN	7.8	2.3
SP AusNet	11.3	1.8
United Energy	7.9	2.7
Average	*8.1*	*2.2*
AER final decision		
CitiPower	–1.6	2.9
Powercor	1.1	2.5
JEN	3.1	2.3
SP AusNet	5.1	2.9
United Energy	1.2	2.6
Average	*1.8*	*2.6*

The impact on retail prices for residential customers from the AER's final decision is shown in table 5 above. The AER's decision means retail prices will rise on average by 1.8 per cent in the first year and 2.6 per cent per year between 2012 to 2015. For individual businesses, this ranges from an initial reduction of 1.6 per cent for

Citipower to an increase of 5.1 per cent for SP AusNet. Thereafter, annual increases are between 2–3 per cent. These increases are significantly lower than those proposed by the DNSPs.

Chapter summary

This section sets out the key components of the AER's final decision – summarising the AER's draft decision, the Victorian DNSPs' revised proposals and the AER's final decision.

Classification of services

AER draft decision

The AER's draft decision set out the following service classification, in response to the Victorian DNSPs regulatory proposals (which in turn, responded to the service classification set out in the AER's framework and approach paper):

- new connections requiring augmentation works as standard control services
- routine connections as alternative control services
- covering of low voltage mains as an alternative control service (quoted services)
- elective undergrounding where an above ground services exists as an alternative control service (quoted service)
- covering of damage to overhead service cables caused by high load vehicles as alternative control services (quoted services)
- high load escorts—lifting overhead lines as alternative control services (quoted services)
- classification of location of underground cables as a standard control service
- meter investigation as an alternative control service (fee based)
- special meter reading as an alternative control service (fee based)
- PV installation as an alternative control service (fee based)

A full list of services was set out at appendix D of the AER's draft decision.

Victorian DNSP revised regulatory proposals

The Victorian DNSPs generally accepted the AER's draft decision service classification. JEN noted that it did not agree with the AER's classification of routine connection services, but had accepted it for the purposes of drafting its revised regulatory proposal. In its regulatory proposal, JEN also submitted that supply abolishment services should be treated as quoted alternative control services, rather than fee based alternative control services. In support, JEN noted that costs associated with this service are highly variable.

After the submission of its revised regulatory proposal, JEN also submitted that the AER should classify reserve feeder services as negotiated services. SP AusNet, after submission of its revised regulatory proposal, proposed that it's after hours truck by appointment service should be treated as a quoted alternative control service.

AER final decision

The AER maintains its approach to service classification set out in the draft decision, save for:

- treating supply abolishment services as a quoted service, rather than a fee based service
- treating after hours truck by appointment services as a quoted service, rather than a fee based service.

Chapter 2 and appendix B of this final decision set out the full discussion on service classification.

Negotiated distribution services

AER draft decision

The AER's draft decision determined that the proposed negotiating frameworks submitted by CitiPower and Powercor (submitted with their initial regulatory proposals) were compliant with the NER. The AER determined that negotiating frameworks submitted by JEN, SP AusNet and United Energy were not compliant. The AER required several minor amendments to these. These amendments were set out at appendix C of the draft decision.

Victorian DNSP revised regulatory proposals

CitiPower and Powercor did not submit revised negotiating frameworks. JEN, SP AusNet and United Energy each submitted negotiating frameworks which incorporated the amendments required by the AER.

AER final decision

The negotiated distribution services criteria (NDSC) to apply to CitiPower, Powercor, JEN, SP AusNet and United Energy for the forthcoming regulatory control period are set out in appendix D of this final decision.

The AER approves the negotiating frameworks submitted by CitiPower and Powercor in their initial regulatory proposal, and approves the negotiating frameworks submitted by JEN, SP AusNet and United Energy with their revised regulatory proposals.

Chapter 3 and appendices C and D of this final decision set out the full discussion on arrangements for negotiation.

Price control formula for standard control services

AER draft decision

The AER, in its draft decision, set out the weighted average price cap (WAPC) and side constraint formulae that applies to the Victorian DNSPs in the forthcoming regulatory control period.

The AER agreed with SP AusNet's and United Energy's interpretation of the NER, that is, that the NER does not allow DNSPs to recover at the pricing proposal stage connection charges levied upon them by TNSPs. The AER also considered that the NER does not allow DNSPs to recover at the pricing proposal stage inter-DNSP charges and avoided TUOS charges.

The AER’s procedure for assigning and reassigning customers to tariff classes for the Victorian DNSPs was set out in appendix G of the draft decision.

Victorian DNSP revised regulatory proposals

CitiPower, Powercor, JEN and SP AusNet proposed a new specification for the price control formula for standard control services. CitiPower, Powercor and JEN considered that this is necessary to comply with the control formula where there are changes to tariff structures such as when tariff reassignments occur. A similar specification was proposed for the side constraint formula.

United Energy proposed that the side constraint should not constrain movements between tariff classes. JEN proposed that the control formula compliance arrangements in appendix E of the draft decision should be amended to achieve this.

Given the uncertainty regarding the recovery of transmission connection charges, inter-DNSP charges, and avoided TUOS under clause 6.18.7 of the NER the Victorian DNSPs proposed various mechanisms for the recovery of those charges.

AER final decision

The AER consulted with the Victorian DNSPs regarding the specification of the price control formula and does not propose to amend the formula as proposed by the DNSPs. The AER considers that there is sufficient flexibility in the formula to account for changes to tariff structures such as tariff reassignments.

The AER has made amendments to appendix E of the draft decision to address United Energy’s and JEN’s concerns regarding the side constraint’s possible constraining of movements between tariff classes.

The recovery of transmission connection charges, inter-DNSP charges, and avoided TUOS is discussed in chapter 4, chapter 16 and appendix L of this final decision.

The AER’s procedure for assigning and reassigning customers to tariff classes for the Victorian DNSPs is set out in appendix G of this final decision.

Peak demand, energy consumption and customer forecast numbers

AER draft decision

The draft decision stated that the maximum demand forecasts proposed by the Victorian DNSPs were not a realistic expectation of the demand forecast required to achieve the capex and opex objectives and were not appropriate to form amounts, values or inputs to the AER's determination. In place of the Victorian DNSPs' proposed forecasts, the draft decision approved maximum demand forecasts for selected zone substations in each DNSP's network.

The draft decision also considered that the Victorian DNSPs' proposed energy consumption and customer number forecasts were not appropriate to form amounts, values or inputs to the AER's determination under clause 6.12.1(10) of the NER. The AER amended the Victorian DNSPs' demand and energy forecasts to remove assumed policy impacts for standby power, insulation subsidy and time of use (TOU) tariffs. The AER also replaced the Victorian DNSPs' proposed population growth forecasts, which affected their energy forecasts. The draft decision requested that the DNSPs' revised proposal growth forecasts include updated gross state product (GSP) forecasts, population growth forecasts consistent with ABS Series B for Victoria and revised assumptions about the Carbon Pollution Reduction Scheme (CPRS).

The AER's draft decisions on the energy consumption forecasts for the Victorian DNSPs reflected an increase in the average annual growth rate from –1 per cent to 2 per cent. For maximum demand, the AER's draft decision resulted in reductions in the forecasts for selected zone substations for each DNSP, while customer numbers in the draft decision remained unchanged from the initial proposals, noting the request to amend the population growth and economic growth inputs.

Victorian DNSP revised regulatory proposals

In their revised regulatory proposals, the Victorian DNSPs:

- did not accept the AER's adjustments to their forecasts of energy consumption and maximum demand
- re-engaged the National Institute of Economic and Industry Research (NIEIR) to produce revised energy consumption and top down maximum demand forecasts, using updated assumptions for economic growth, population growth forecasts and for the CPRS, consistent with the AER's draft decision recommendations
- each carried out different approaches and analyses with respect to reconciliation between their spatial maximum demand forecasts and NIEIR's revised maximum demand forecasts
- adopted NIEIR's revised customer number and energy forecasts that reflected updated population growth and GSP forecasts, consistent with the AER's draft decision recommendations

- rejected the AER's draft decision on the impact on the growth forecasts of Government policies on MEPs lighting, standby power, insulation target and AMI

- applied several different approaches to estimating the impact of the AMI rollout on energy consumption, based on NIEIR's estimates (CitiPower, Powercor and United Energy), advice from Frontier Economics (JEN) and SP AusNet's in-house model

- adopted NIEIR's revised policy impacts on electricity sales and maximum demand forecasts (aside from JEN and SP AusNet, regarding AMI impacts).

The Victorian DNSPs' revised proposal energy consumption forecasts reflected an annual average growth rate of 0.3 per cent, as compared to the draft decision average annual growth rate of 2 per cent. The DNSPs' revised regulatory proposal sum of zone substation maximum demand forecasts were on average 0.1 per cent higher than the draft decision average, while customer numbers were on average 0.5 per cent higher than the draft decision.

AER final decision

The AER considers that the spatial maximum demand forecasts proposed by Powercor, JEN and United Energy are reasonable and reflect a realistic expectation of the demand forecasts required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER.

The AER considers that the spatial maximum demand forecasts proposed by CitiPower and SP AusNet do not reflect a realistic expectation of the demand forecasts required to achieve the capex and opex objectives in the NER. In place of CitiPower's and SP AusNet's proposed maximum demand forecasts, this final decision approves the forecasts as set out in tables table 1 and 4 below. In replacing the proposed forecasts, the AER has made the minimum necessary amendments to enable the forecasts to be approved in accordance with the NER.

Given the Victorian DNSPs' revised regulatory proposal customer number forecasts reflect reasonable population and economic growth forecasts, the AER considers they are appropriate to form amounts, values or inputs to the AER's determination.

The AER considers that the Victorian DNSPs' revised regulatory proposal energy consumption forecasts reflect unreasonable assumptions about the one-watt standby target policy and the introduction of time of use (TOU) tariffs in Victoria. In particular, the AER considers there is insufficient evidence of a government policy to implement one watt standby targets for all household appliances, that customer behaviour has moved ahead of the 2002 National Standby Strategy and other energy saving schemes include one watt standby targets, negating the need for the policy to be implemented via a mandatory target scheme. As such, the underlying trend energy consumption in Victoria already reflects the move to one-watt standby, and to adjust the forecasts for a mandatory target scheme would be double-counting the impact. Following the extension of the Victorian Government's moratorium on TOU tariffs and its intention to apply constraints to differentials between peak and off-peak prices, the AER considers that NIEIR's assumption on customer response to TOU tariffs by 2015 does not reflect a reasonable expectation of energy consumption. In making this final decision, the AER has made the following amendments to the DNSPs' energy forecasts:

- CitiPower, Powercor and United Energy—removed the one-watt standby target assumption; removed NIEIR's assumed impact of TOU tariffs and replaced it with Frontier's estimated impacts for residential and commercial customers, commencing in 2012
- JEN—removed the one watt standby target assumption; applied JEN's corrected calculation of Frontier's estimated impacts of TOU tariffs for residential and commercial customers, commencing in 2012
- SP AusNet—removed the one watt standby target assumption; applied SP AusNet's own calculation of estimated impacts of TOU tariffs using its TOU tariff model, commencing in 2012.

These amendments to the revised regulatory proposal energy forecasts have been made by requesting the DNSPs to model the AER's final decisions, and are the minimum necessary amendments to enable the forecasts to be approved in accordance with the NER. In place of the Victorian DNSPs' proposed energy consumption forecasts, this final decision approves the forecasts as set out in tables 1 to 5 below.

Table 1 AER conclusion on growth forecasts—CitiPower

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 510	1 552	1 593	1 634	1 677
Energy consumption (GWh)	6 180	6 227	6 218	6 201	6 237
Customer numbers	316 818	322 742	327 190	331 100	337 050

Table 2 AER conclusion on growth forecasts—Powercor

	2011	2012	2013	2014	2015
Sum of coincident zone substations (MW)	2 481	2 557	2 652	2 747	2 848
Energy consumption (GWh)	10 726	10 795	10 781	10 761	10 797
Customer numbers	717 745	731 603	745 570	759 343	772 544

Table 3 AER conclusion on growth forecasts—JEN

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 099	1 130	1 161	1 192	1 212
Energy consumption (GWh)	4 334	4 322	4 271	4 222	4 205
Customer numbers	310 165	315 890	320 889	325 174	329 428

Table 4 AER conclusion on growth forecasts—SP AusNet

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 874	1 959	2 046	2 130	2 219
Energy consumption (GWh)	7 975	7 978	7 961	7 974	8 042
Customer numbers	633 847	646 034	657 240	667 352	677 204

Table 5 AER conclusion on growth forecasts—United Energy

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	2 359	2 424	2 495	2 576	2 591
Energy consumption (GWh)	7 936	7 964	7 905	7 842	7 836
Customer numbers	627 203	633 295	638 757	643 600	648 220

Outsourcing arrangements

AER draft decision

The AER noted that outsourcing to specialist providers of a particular service is a common means by which businesses in the economy are able to gain access to economies of scale and scope and other efficiencies (for example, ‘know-how’). Accordingly, the AER stated services providers should be provided with effective incentives to seek out efficient and prudent outsourcing arrangements.

At the same time, the AER recognised that an incentive exists for a service provider to engage in related party transactions on non-arm’s length terms. The result of this being that the service provider’s reported expenditure might be ‘artificially inflated’, and that the benefits of efficiencies realised by the service provider and its related party contractors might be retained by their shareholders for longer than intended under the regulatory regime (and potentially even indefinitely), rather than being shared with consumers after a period of time. Accordingly, the AER considered outsourcing arrangements should be assessed closely against the requirements of the NEL and NER.

The AER developed a conceptual framework to assist it in assessing the Victorian DNSPs' operating and capital expenditure forecasts against the requirements of the NER. In developing this framework, the AER had regard to the Victorian DNSPs' proposals and the past regulatory debate on this issue.

The first stage of the AER's framework referred to a 'presumption threshold' designed to be an initial filter to determine which contracts it can be reasonably presumed to reflect efficient costs and costs that would be incurred by a prudent operator, and which contracts don't have that presumption. In undertaking this 'presumption threshold' assessment, the AER considered the two relevant considerations were:

- Did the service provider have an incentive to agree to non-arm's length terms at the time the contract was negotiated (or at its most recent re-negotiation)?—the AER considered the most common circumstance where this arises is where the arrangement is with a related party.
- If yes, was a competitive open tender process conducted in a competitive market?

In the absence of an incentive to agree to non-arm's length terms, the AER considered it reasonable to presume the contract price reflects efficient and prudent costs. The AER considered this presumption is also reasonable where an incentive to agree to non-arm's length terms exists, however the contract was subject to a competitive open tender process in a competitive market.

Where an arrangement 'passes' the presumption threshold, the AER considered the starting point for setting future expenditure allowances should be the contract price itself, with limited further examination required. This further examination involved checking whether the contract wholly relates to the relevant services (for example, standard control services) and whether the (efficient) contract price already compensates for risks or costs provided for elsewhere in the building blocks, leading to a 'double-counting' of such risks or costs.

The AER identified some limited concerns with the tendering processes conducted by United Energy in the appointment of its 'turn key service provider' to replace Jemena Asset Management. However, the AER still considered that this arrangement passed the presumption threshold. The AER also considered it was reasonable to presume SP AusNet's arrangement with Tenix Alliance reflects efficient and prudent costs. Both these arrangements are with parties who are not related to the service provider.

Where a contract does not pass the presumption threshold, the AER considered the starting point for setting future expenditure allowances should be the contractor's actual direct costs with a 'margin' above this level permitted only where the service provider is able to establish the efficiency and prudency of such a margin against legitimate economic reasons for the inclusion of the margin (and its quantum).

As the related party arrangements of each of the Victorian DNSPs did not pass the presumption threshold the AER considered whether a margin above the related parties' direct costs is appropriate. The reasons the AER considered legitimate for the inclusion of a margin were:

- to compensate for a share of the contractor's corporate and other indirect costs
- to provide a return on and return of assets owned and utilised by the contractor, but only where those assets are not already contained in the service provider's regulatory asset base (RAB)
- to compensate for asymmetric risks faced by the contractor, but only where the service provider's proposed self insurance allowance has been reduced commensurately with the risks passed on to the contractor that it no longer faces, and
- to retain the benefit of historical efficiencies for a period of time.

As the AER's assessment had already factored in a share of the related party's corporate costs into the expenditure forecasts, no additional 'margin' was required to compensate.

The AER was not aware of the existence of any assets owned and utilised by related party contractors that were not already contained within the Victorian DNSPs' RABs. Additionally, the Victorian DNSPs proposed self insurance allowances related to the risks faced on their network and had not been adjusted to reflect risks passed on to their contractors through their pricing arrangements. Therefore the inclusion of a margin had not been substantiated against these reasons.

Finally, as the AER sought to reward the Victorian DNSPs for the historical efficiencies realised by their related parties through the efficiency carryover mechanism (ECM) allowance, no margin was required for this reason. In this context, the AER did not consider outsourcing arrangements should be assessed against a 'standalone, in-house' cost standard. The Victorian DNSPs' related parties had achieved substantial economies of scale and scope from operating multiple networks. However the AER did not consider it was appropriate under the NER for these benefits to be retained indefinitely by the service provider's and related parties' shareholders. Rather, consistent with the treatment of other efficiencies under the regulatory regime, the AER considered the benefit of operating efficiencies should be retained for six years and the benefit of capital efficiencies retained until the end of the regulatory control period in which they are realised.

Victorian DNSP revised regulatory proposals

The alternative assessment framework proposed by CitiPower and Powercor in their revised regulatory proposals adopted the AER's presumption threshold without modification. SP AusNet did not agree with the presumption threshold where the service provider had minority shareholders who did not have an ownership stake in the related party contractors. JEN and United Energy did not comment on the presumption threshold.

SP AusNet supported the AER's assessment approach of contracts that do not pass the presumption threshold. JEN also supported the AER's legitimate economic reasons in respect of corporate overheads, assets used by the contractor and asymmetric risk. JEN confirmed that its related party contractors did not use any significant assets in providing services to JEN.

However, CitiPower, Powercor and JEN did not agree with the AER’s rejection of a ‘standalone, in-house’ cost standard by which to assess contract prices. The DNSPs have put forward legal and economic reasons to support this standard, including referencing the Tribunal’s support for a ‘standalone’ operator benchmark in Re Optus Mobile Pty Limited & Optus Networks Pty Limited [2006] ACompT 8 (22 November 2006).

Essentially, CitiPower, Powercor and JEN considered it would still be an efficient outcome for their related party contractors to retain the benefit of historical efficiencies indefinitely. Alternatively if these were to be shared with the DNSPs and ultimately consumers, it was an efficient and prudent outcome for this timing to be at the discretion of the related parties.

CitiPower, Powercor and JEN also argued the AER’s approach creates a perverse incentive for DNSPs to internalise activities that are currently outsourced, even where outsourcing is the more efficient option.

AER final decision

The AER has maintained the presumption threshold from its draft decision. Applying this threshold to the Victorian DNSPs outsourcing arrangements has led to the same arrangements passing and not passing this threshold as set out in the draft decision.

The AER reviewed each of the reasons put forward by CitiPower, Powercor and JEN in support of a standalone, in-house cost standard.

The AER considered the decisions of each of the Victorian DNSPs (especially CitiPower, Powercor, JEN and SP AusNet) to outsource significant activities to centralised, specialist operators within their corporate structures appears consistent with good business practice. This is primarily because of the significant economies of scale and scope that each of these operators can achieve through operating multiple networks. The fact that significant economies of scale and scope have been achieved is not in dispute.

Accordingly, the AER's concerns are not over the Victorian DNSPs' corporate structures, per se, but rather over the pricing arrangements agreed to by the Victorian DNSPs and these related party contractors. Specifically, whether these pricing arrangements reflect efficient costs and costs that a prudent operator in each of the Victorian DNSPs' circumstances would occur.

The AER considers that the term 'circumstances' should be given its ordinary meaning which includes both the network operating circumstances and corporate structure and ownership circumstances of the relevant DNSP.

The AER expects that a prudent operator would not agree to continue to pay a contractor standalone, in-house costs (the costs it incurred pre-outsourcing), and would only agree to pay something less than this amount as it would require that it receives a share of the contractor's economies of scale and scope (which it has helped the contractor achieve by virtue of outsourcing its activities to the contractor).

Consequently, the AER considers that the prudency criterion provides guidance that the appropriate cost standard is some amount less than 'standalone, in-house' costs, and that the efficiency criterion provides more precise guidance for how much less than the standalone, in-house costs is appropriate.

It’s accepted by CitiPower, Powercor and JEN that the expected pricing outcomes from a workably competitive market is an appropriate framework to consider the meaning of efficient costs. There is also general acceptance that in a workably competitive market a contractor cannot continue to earn a margin above its full economic costs (that is, earn abnormal profits) for efficiencies it has realised in the past. The issue in contention is over what time period this pass back of historical efficiencies to consumers would be expected to occur in a workably competitive market.

The AER has adopted a retention period of six years for operating efficiencies and until the end of the regulatory control period for capital efficiencies. This is consistent with the regulatory framework set up by the AEMC for the treatment of efficiencies. And in setting up this framework the AEMC acknowledged that the fundamental goal of incentive regulation was to replicate a workably competitive market. The AEMC also stated that in a competitive market historical efficiencies are eventually passed through to consumers.

The AER has reviewed the margin benchmarking submitted by CitiPower, Powercor and JEN. The AER notes that this margin benchmarking does not suggest a particular retention period. The AER also noted three studies referred to by the QCA is setting up its efficiency carryover mechanism which suggest that in commercial reality firms do not retain the benefit of efficiencies for longer than five years. Based on these factors, the AER considers that its proposed retention periods are a reasonable approximation of observed commercial practice.

The AER has also reviewed the ATO guidelines material submitted by CitiPower and Powercor, but considers that the different objectives of the tax and economic regulatory regimes means that related party transactions made under the ATO guidelines should not be assumed to automatically also meet the NER requirements.

Accordingly, while the AER has had regard to the margin benchmarking and ATO material it has not persuaded the AER to depart from the retention periods which are consistent with the treatment of efficiencies realised by DNSPs themselves. The AER considers consistency between the treatment of efficiencies realised by related parties and the DNSPs themselves to be an important consideration. The AER considers these retention periods are consistent with the expected pricing outcomes from a workably competitive market.

The interaction with the EBSS is also important. The AER's approach results in historical operating efficiencies being rewarded through the EBSS. This approach is appropriate because the AER can not reasonably assume that the DNSPs and their related parties will pass back efficiencies to consumers in an appropriate timeframe. The AER also notes that it considers the initial division of the benefit from historical efficiencies between the DNSP and its related party is a matter entirely up for them to decide. The AER is concerned about when consumers share in these benefits, not the dividing up of the benefit between the DNSP and related party before it is passed back to consumers.

Finally, the AER considers the adoption of a standalone cost standard is not consistent with the NEO as while it would promote efficiencies, it would not promote efficiencies in the long term interests of consumers as consumers would not share in these efficiencies. The AER's retention periods ensure DNSPs and related party contractors are provided with effective incentives—in accordance with the relevant revenue and pricing principle—to pursue efficiencies (because they get to keep the benefit for a period of time) while also promoting the NEO because consumers share in the benefit of the efficiencies after a period of time.

Forecast operating expenditure

AER draft decision

In its draft decision, the AER was not satisfied that the total operating expenditure (opex) forecast proposed by each of the Victorian DNSPs reasonably reflected the opex criteria in the NER, taking into account the opex factors.

Based on the AER's analysis of the Victorian DNSPs' regulatory proposals and submissions received, the AER applied a reduction of $763 million ($2010) to the DNSPs' forecast opex. This represents a reduction of around 26 per cent and resulted in a revised total opex forecast for the DNSPs of $2 190 million ($2010). The AER's draft decision conclusion of each Victorian DNSP is set out in table 6.

Table 6 AER draft decision opex allowance for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
DNSP proposed opex	**244.0**	**902.2**	**319.4**	**885.7**	**601.8**	**2 953.2**
AER opex build-up						
AER base year costs	164.5	578.3	220.0	588.2	424.8	1975.7
AER scale escalation	1.4	8.8	2.5	8.4	4.6	25.8
AER real cost escalation	7.6	28.1	9.5	19.5	17.6	82.4
AER step changes	6.0	–8.1	10.7	25.0	10.9	44.5
AER debt raising costs	3.8	6.3	2.2	6.0	4.0	22.2
AER self insurance	–	–	0.5	–	0.1	0.6
AER other[a]	1.1	8.9	1.1	24.7	3.3	39.1
AER total opex	**184.4**	**622.3**	**246.5**	**671.8**	**465.3**	**2 190.3**
Adjustment	**–59.6**	**–280.0**	**–72.9**	**–213.9**	**–136.5**	**–762.9**
Adjustment (per cent)	**–24.4**	**–31.0**	**–22.8**	**–24.2**	**–22.7**	**–25.8**

Source: AER, *Draft decision*, p. 274.
[a]DMIS, GSL

Victorian DNSP revised regulatory proposals

The Victorian DNSPs' revised regulatory proposal total forecast opex amounts for the forthcoming regulatory control period totalled $3 130.7 million ($2010). This represents an increase of $1 075.4 million, or 52 per cent from the Victorian DNSPs' expected actual opex of $2 055.3 million ($2010) in the current regulatory control period.

As in its initial regulatory proposal, United Energy did not adopt the same 'base, step and trend' approach to opex forecasting as the other Victorian DNSPs as it stated the new business model it was adopting in the forthcoming regulatory control period did not suit that forecasting approach.

Table 7 summarises each Victorian DNSP's revised forecast opex for the forthcoming regulatory control period. For further information refer to chapter 7.

Table 7 Victorian DNSP revised proposal opex allowance for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
DNSP opex build-up[a]						
Base year costs	185.7	648.2	243.5	613.0	550.1	2240.5
Scale escalation	6.7	28.7	8.4	20.7	–	64.6
Real cost escalation	14.3	58.0	21.2	34.0	–	127.5
Step changes	32.4	136.8	46.0	285.8	83.1	584.0
Related party margins	15.5	36.1	19.2	–	–	70.8
Debt raising costs	11.0	18.8	2.6	6.5	4.3	43.3
DNSP total opex	**265.7**	**926.6**	**340.8**	**960.1**	**637.5**	**3130.7**

Source: Victorian DNSP revised RINs, revised PTRMs.
[a]Excludes DMIA allowance.

AER final decision

In this final decision, the AER has continued to allow opex for the impact of network growth (scale escalation) including expected productivity improvements, and has allowed the value of the Victorian DNSPs' opex allowance to be maintained in real terms (incorporating changes in real input costs for labour and materials).AER final decision opex allowance for 2011–15 ($'m, 2010).

The AER has also reconsidered its approach to assessing step changes and has decided not to apply the Wilson Cook criteria. As stated in the draft decision and this final decision, the AER has assessed step changes solely against the opex criteria and the opex factors in clause 6.5.6 of the NER, in a manner consistent with the NEO, and which takes into account the revenue and pricing principles.

Despite this, the AER notes that the Victorian DNSPs have received greater opex allowances than in the draft decision, due to new regulatory obligations and changes to the DNSPs’ operating environments, which have resulted in increased opex allowances relating to safety (particularly for line clearance regulations), IT, insurance, customer communications and some DNSP specific step changes.

However, the AER has not provided additional opex for Victorian Bushfire Royal Commission (VBRC) recommendations despite the recommendations being published on 31 July 2010. Consistent with the draft decision, the AER considered that any legislated outcomes following the VBRC may be treated as a pass-through event, subject to the requirements of clause 6.6.1 of the NER.

Consistent with the draft decision, the AER did not provide any step change for opex arising from climate change because the costs associated with extreme wither will be reflected in the actual opex of the Victorian DNSPs in 2009.

As noted in the draft decision, while it is too early to evaluate the expected DNSP efficiencies arising from the AMI (smart meters) rollout, the AER expects that such efficiencies will be evident over time and will impact on operating cost trends over time. Through its annual reporting framework, the AER will monitor AMI impacts on operating costs.

The AER has considered the Victorian DNSPs’ forecast opex and the AER is not satisfied that the total opex forecast proposed by each of the Victorian DNSPs reasonably reflects the opex criteria in clause 6.5.6(c) of the NER.

Based on the AER’s analysis of the Victorian DNSPs’ revised regulatory proposals, submissions received and advice from Nuttall Consulting, the AER has applied a reduction of $417.1 million ($2010) to the Victorian DNSPs’ forecast opex. This represents a reduction of around 13 per cent and results in a revised total opex forecast for the DNSPs of $2 713.6 million ($2010). The AER’s estimate of each DNSP’s required opex for the forthcoming regulatory control period is set out in table 8 below.

The AER did not accept United Energy's opex forecast, and substituted it for an estimate derived from the AER's assessment of required opex derived from a base, step and trend forecasting approach, in the same manner as for the other Victorian DNSPs.

Table 8 AER final decision opex allowance for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
DNSP proposed opex	**265.7**	**926.6**	**340.8**	**960.1**	**637.5**	**3130.7**
AER opex build-up[a]						
AER base year costs	185.7	648.1	231.7	600.4	460.8	2126.7
AER scale escalation	3.9	17.7	3.8	10.8	4.8	41.0
AER real cost escalation	8.7	31.7	9.2	24.9	20.2	94.6
AER step changes[b]	26.4	88.9	36.3	185.9	56.1	393.6
AER debt raising costs	3.9	6.6	2.4	6.5	4.2	23.5
AER self insurance	–	–	0.5	6.5	0.1	7.1
AER other (GSL)	0.1	5.5	0.1	20.1	1.3	27.0
AER total opex	**228.6**	**798.4**	**284.0**	**855.1**	**547.5**	**2713.6**
Adjustment	**–37.1**	**–128.2**	**–56.8**	**–105.0**	**–90.0**	**–417.1**
Adjustment (per cent)	**–13.9**	**–13.8**	**–16.7**	**–10.9**	**–14.1**	**–13.3**

Source: AER analysis.
[a]Excludes DMIA allowance.
[b]Includes real cost escalation.

The AER considers this reduction is the minimum adjustment necessary to ensure the Victorian DNSPs' total opex forecasts reasonably reflect the opex criteria. Chapter 7 contains the AER's final decision on forecast opex for the Victorian DNSPs.

Forecast capital expenditure

AER draft decision

In its draft decision, the AER was not satisfied that the total capex forecast proposed by each of the Victorian DNSPs reasonably reflected the capex criteria in the NER taking into account the capex factors.

Based on the AER's analysis of the Victorian DNSPs' regulatory proposals, submissions received and advice from Nuttall Consulting, the AER applied a reduction of $2 030 million ($2010) to the DNSPs' forecast capex. In aggregate terms, this represented a reduction of around 38 per cent and resulted in a revised total capex forecast for the DNSPs of $3 376 million ($2010).

In the draft decision, a reduction of $491 million, or 46 per cent was applied to CitiPower. For Powercor, a reduction of $578 million, or 36 per cent was applied. A reduction of $285 million or 48 per cent was applied to JEN. For SP AusNet, a reduction of $418 million, or 31 per cent was applied. A reduction of $269 million or

33 per cent was applied to United Energy. The AER's draft decision conclusion for each Victorian DNSP is set out in table 9.

Table 9 AER draft decision conclusion on Victorian DNSPs' capex ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
Total gross capex	**675.8**	**1 300.2**	**371.5**	**1 065.6**	**652.4**	**4 065.5**
Less customer contributions	108.5	291.0	56.9	112.2	120.9	**689.4**
Total net capex	**567.4**	**1 009.2**	**314.6**	**953.3**	**531.5**	**3 376.1**
Adjustments	**–490.7**	**–578.3**	**–285.1**	**–418.2**	**–258.5**	**–2 030.8**
Adjustments (per cent)	**–46.4**	**–36.4**	**–47.5**	**–30.5**	**–32.7**	**–37.6**

Source: AER draft decision, p.xxxii

Victorian DNSP revised regulatory proposals

The Victorian DNSPs' revised regulatory proposals combined total forecast capex for the forthcoming regulatory control period is $5 487 million ($2010). This represents an increase of $2 255 million, or 70 per cent from the Victorian DNSPs' expected actual capex of $3 232 million ($2010) in the current regulatory control period.

Table 10 summarises each Victorian DNSP's forecast capex for the forthcoming regulatory control period. For further information refer to chapter 8.

Table 10 Victorian DNSPs' proposed capex for the forthcoming regulatory control period ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
Total gross capex	**1 004.6**	**1 825.6**	**620.7**	**1 581.5**	**949.4**	**5 981.7**
Less customer contributions	55.4	219.2	38.8	47.7	134.0	495.1
Total net capex	**949.2**	**1 606.4**	**581.9**	**1 533.8**	**815.4**	**5 486.6**

Source: CitiPower, *Revised Regulatory Proposal*, RIN template 2.1, Powercor, *Revised Regulatory Proposal*, RIN template 2.1, JEN, *Revised Regulatory Proposal*, RIN template 2.1, SP AusNet, *Revised Regulatory Proposal*, RIN template 2.1, United Energy, *Revised Regulatory Proposal*, RIN template 2.1.

AER final decision

The AER has considered the Victorian DNSPs' forecast capex and is not satisfied that the total of each of the Victorian DNSP's proposed forecast capex reasonably reflects the capex criteria in accordance with clause 6.5.7(c) of the NER, taking into account the capex factors.

Based on the AER's analysis of the Victorian DNSPs' regulatory proposals, submissions received and advice from Nuttall Consulting, the AER has applied a reduction of $792 million ($2010) to the DNSPs' combined revised forecast capex. This represents a reduction of around 14 per cent from the Victorian DNSPs' revised regulatory proposals, and results in a final decision allowance for total capex of $4 695 million ($2010). The AER considers that this reduction is the minimum adjustment necessary to ensure the Victorian DNSPs capex forecast meets the capex criteria. For CitiPower, the AER has applied a reduction of $182 million ($2010), or 19 per cent. The reduction applied to Powercor was $283 million ($2010), or 18 per cent. A reduction of $148 million ($2010), or 25 per cent was applied to JEN. For SP AusNet, a reduction of $117 million ($2010), or 8 per cent was applied. A reduction of $63 million ($2010), or 8 per cent was applied to United Energy.

Chapter 8 contains the AER's final decision on forecast capex for Victorian DNSPs. The AER's conclusion of each Victorian DNSP's required capex for the forthcoming regulatory control period is set out in table 11 below.

Table 11 AER conclusion on Victorian DNSPs' capex for the forthcoming regulatory control period ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
System assets						
Demand related						
Reinforcement	212.7	230.4	92.4	288.3	172.3	996.1
Gross new customer connections	228.6	574.9	136.6	372.7	238.6	1551.4
Non-demand related						
Reliability and quality maintained	125.1	129.0	47.9	119.6	109.3	530.7
Reliability and quality improved	–	–	–	–	–	–
Environmental, safety and legal obligations	29.4	208.9	76.1	212.2	209.2	735.8
Sub-total system assets	595.8	1143.2	352.9	992.8	729.4	3814.0
Non-system assets						
SCADA and network control	10.8	17.2	2.8	4.8	3.7	39.3
Non-network–IT	43.4	106.4	59.6	143.0	110.9	463.3
Non-network–other	14.9	74.5	30.5	20.7	17.0	157.7
Sub-total non-system assets	69.1	198.1	92.9	168.5	131.7	660.3
Total gross direct capex	664.9	1341.3	445.8	1161.3	861.0	4474.3
Direct overheads	52.7	26.6	8.9	–	–	88.2
Indirect overheads	61.0	106.0	13.4	189.3	–	369.7
Cost changes	51.7	93.5	5.3	130.6	25.7	306.9
Related party margins	–	–	–	–	–	–
Total gross capex	**830.3**	**1567.4**	**473.4**	**1481.2**	**886.8**	**5239.1**
Less customer contributions	62.9	243.7	39.5	64.2	134.0	544.3
Total net capex	**767.5**	**1323.7**	**433.9**	**1416.9**	**752.8**	**4694.8**
Adjustments	**-181.7**	**-282.6**	**-148.0**	**-116.9**	**-62.6**	**-791.8**
Adjustments (per cent)	**-19%**	**-18%**	**-25%**	**-8%**	**-8%**	**-14%**

Opening regulatory asset base

AER draft decision

The AER in the draft decision identified the following issues in relation to the Victorian DNSPs' RAB roll forward models:

- reconciliation of data inputs
- adjustments arising from 2005 expenditure estimates
- inflation methodology for the RAB forward model
- financing cost for JEN's capex overspend
- related party profit margin adjustment
- decision to apply actual or forecast depreciation.

The rolled-forward values for Victorian DNSPs' opening RABs as at 1 January 2011 in the draft decision are summarised in table 12.

Table 12 AER draft decision on Victorian DNSPs' closing RAB ($’m, 2010)

	2006	**2007**	**2008**	**2009**	**2010**
CitiPower	1 194.1	1 197.6	1 206.5	1 233.5	1 286.5
Powercor	1 978.7	2 034.4	2 093.0	2 136.2	2 204.9
JEN	673.9	695.0	691.1	708.3	742.2
SP AusNet	1 631.0	1 676.0	1 775.8	1 935.8	2 094.2
United Energy	1 381.5	1 359.0	1 334.3	1 365.1	1 387.7

Source: AER, Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015, June 2010, p. 455.

Victorian DNSP revised regulatory proposals

Victorian DNSPs' revised RAB roll forward calculations for the 2006–10 regulatory period are summarised at table 13.

Table 13 Victorian DNSP revised RAB roll forward for the 2006–10 regulatory period (closing RAB value, $’m, 2010)

	2006	2007	2008	2009	2010
CitiPower	1 194.3	1 197.8	1 206.7	1 233.4	1 287.6
Powercor	1 980.1	2 035.8	2 094.4	2 137.5	2 214.7
JEN	676.1	698.1	695.1	722.1	766.2
SP AusNet	1 634.3	1 680.4	1 782.0	1 920.7	2 079.6
United Energy	1 381.5	1 359.0	1 334.3	1 358.6	1 381.2

Source: Victorian DNSPs’ revised regulatory proposals, RAB roll forward models, July 2010.

AER final decision

The AER has reviewed (including by cross checks against their regulatory accounts) the Victorian DNSPs’ proposed opening RAB values and the cost inputs to the RFM for the 2006–10 regulatory period. The AER identified the following issues and made adjustments for them accordingly:

- reconciliation of data inputs
- adjustments arising from 2005 expenditure estimates
- inflation methodology for the RAB forward model

In response to concerns raised by stakeholders, the AER re-examined the DNSPs' proposals to capitalise related party margins into their RABs, however considers they fall within the definition of "capital expenditure incurred" under the NER and must be included.

The AER has determined opening RAB values for the Victorian DNSPs as set out in table 14. For this final decision, the AER has applied:

- an opening RAB for Victorian DNSPs as at 1 January 2011 to the PTRM for the purposes of determining the annual revenue requirement during the 2011–15 regulatory control period
- actual depreciation for establishing the RAB for the commencement of the 2016–20 regulatory control period.

Chapter 9 contains the final decision on the opening RAB values for Victorian DNSPs.

Table 14 AER conclusion on Victorian DNSPs' opening RABs ($’m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 176.8	1 194.1	1 197.6	1 206.5	1 233.1
Net capex	93.6	79.1	84.6	97.1	125.8
Depreciation	76.3	75.7	75.6	70.5	72.0
Compound return on 2005 capex difference					0.4
Closing RAB	1 194.1	1 197.6	1 206.5	1 233.1	1 287.3
Difference from proposed RAB					–0.3
Powercor					
Opening RAB	1 916.8	1 978.7	2 034.4	2 093.0	2 136.1
Net capex	182.0	176.5	181.0	168.0	207.2
Depreciation	120.1	120.9	122.4	124.9	126.1
Compound return on 2005 capex difference					–4.3
Closing RAB	1 978.7	2 034.4	2 093.0	2 136.1	2 212.8
Difference from proposed RAB					–1.9
JEN					
Opening RAB	654.4	676.1	698.1	695.1	722.1
Net capex	64.4	66.3	42.2	73.3	91.8
Depreciation	42.7	44.3	45.1	46.3	46.8
Compound return on 2005 capex difference					–10.6
Closing RAB	676.1	698.1	695.1	722.1	756.5
Difference from proposed RAB					–9.7

SP AusNet					
Opening RAB	1 582.8	1 633.0	1 680.4	1 782.6	1 917.4
Net capex	134.1	139.9	200.8	238.4	256.1
Depreciation	84.0	92.5	98.5	103.7	109.2
Compound return on 2005 capex difference					10.6
Closing RAB	1 633.0	1 680.4	1 782.6	1 917.4	2 074.9
Difference from proposed RAB					–4.7

United Energy					
Opening RAB	1 388.6	1 381.5	1 359.0	1 334.3	1 357.6
Net capex	97.7	83.9	85.4	116.8	124.9
Depreciation	104.8	106.4	110.1	93.4	82.6
Compound return on 2005 capex difference					–19.7
Closing RAB	1 381.5	1 359.0	1 334.3	1 357.6	1 380.2
Difference from proposed RAB					–1.0

Depreciation

AER draft decision

The draft decision identified the following issues related to the Victorian DNSPs' proposed regulatory depreciation amounts:

- a minor correction to CitiPower's remaining asset lives for new capex for 'distribution systems assets' and 'non-network general assets-other' to reflect the correct standard asset life
- rejection of United Energy's proposal of $51.6 million ($, 2010) of accelerated depreciation
- increasing the standard life of SP AusNet's 'non-network general assets-other' category to 5 years
- minor amendments to JEN's remaining asset lives to reflect the appropriate expenditure timing assumptions

- changes made to Victorian DNSPs' roll forward calculations, which had indirect impacts on forecast depreciation amounts.

The AER's draft decision determined the Victorian DNSPs' regulatory depreciation allowances for the 2011–15 regulatory control period as set out in table 15.

Table 15 AER draft decision on regulatory depreciation ($’m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	35.2	38.4	41.9	45.6	49.6	**210.6**
Powercor	62.0	68.1	74.6	81.5	88.9	**375.1**
JEN	26.9	30.7	34.7	39.0	32.3	**163.5**
SP AusNet	90.9	47.3	53.8	49.3	40.2	**281.4**
United Energy	36.0	42.7	50.2	57.8	66.2	**252.9**

Source: AER, Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015, June 2010, p. 477.

Victorian DNSP revised regulatory proposals

CitiPower and Powercor accepted the approach set out in the draft decision in relation to the calculation of depreciation and asset lives, except for the AER's minor adjustments and corrections to the RAB roll forward model.

JEN submitted that the average life for a particular asset category is a function of the relative weightings of expenditure on the asset types in the category. JEN argued that the AER needed to recalculate the standard lives of all asset categories to reflect its final determination on capital expenditure.

SP AusNet accepted the asset lives set out in the draft decision. It recalculated its proposed depreciation allowance using the asset lives specified in the draft decision and applying the updated opening RAB value and capex forecasts.

United Energy proposed two additional asset classes, which are, neutral screen services and overloaded transformers, to be included for the calculation of forecast regulatory depreciation. United Energy contended that these assets should be depreciated fully because the existing assets will not be in service at the end of the 2011–15 regulatory control period.

The Victorian DNSPs’ revised regulatory depreciation allowances as calculated by the post-tax revenue model (PTRM) are set out in table 16.

Table 16 Victorian DNSP revised regulatory depreciation ($'m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	34.8	38.6	42.7	46.9	52.5	**215.5**
Powercor	62.2	70.6	79.3	88.1	99.8	**400.0**
JEN	27.0	32.9	39.5	45.4	45.5	**190.2**
SP AusNet	91.9	51.2	62.2	58.2	55.9	**319.3**
United Energy	41.4	49.7	60.8	71.2	79.5	**302.6**

Source: Victorian DNSPs' PTRMs.

The Victorian DNSPs' revised regulatory asset categories and standard lives are set out in table 17.

Table 17 Victorian DNSP revised standard asset lives (years)

Asset category	CitiPower	Powercor	JEN	SP AusNet	United Energy
Sub-transmission	50.0	50.0	44.7	45.0	60.0
Distribution system assets	49.0	51.0	50.0	50.0	35.6
Standard metering	–	–	–	–	–
Public lighting	–	–	–	–	–
SCADA/Network control	13.0	13.0	10.0	5.0	5.0
Non network general assets—IT	6.0	6.0	5.1	5.0	5.0
Non network general assets—other	10.0	15.0	19.9	5.0	7.5
Equity raising costs	46.6	45.2	43.1	46.5	40.7
Neutral Screen Services	–	–	–	–	5.0
Distribution Transformers upgrades	–	–	–	–	5.0

Source: Victorian DNSPs' PTRMs.

AER final decision

The AER has assessed each of the Victorian DNSPs' proposed asset life inputs to the PTRM and considers that the resulting regulatory depreciation calculations are in accordance with clause 6.5.5 of the NER. However the AER has not accepted the resulting values because of changes arising in other parts of this decision, including RAB and capital expenditure.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined the Victorian DNSPs' regulatory depreciation allowances for the 2011–15 regulatory control period, as set out in table 18. Chapter 10 contains the AER’s final decision on the depreciation allowances for the Victorian DNSPs.

Table 18 AER conclusion on regulatory depreciation ($’m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	34.7	38.4	42.3	46.5	51.8	**213.7**
Powercor	62.1	69.9	77.9	86.3	96.8	**393.0**
JEN	26.6	31.7	37.7	43.0	42.9	**181.9**
SP AusNet	91.1	51.2	62.3	58.1	55.1	**317.7**
United Energy	41.0	49.1	59.9	70.1	78.0	**298.0**

Cost of capital

AER draft decision

The draft decision accepted the DNSPs' proposed methods for estimating the WACC with the exception of the market risk premium (MRP) and debt risk premium (DRP).

The Victorian DNSPs all proposed a MRP of 8 per cent. The AER considered the information provided in support of the regulatory proposals but found no persuasive evidence that justified a departure from the MRP of 6.5 per cent set in the SORI.

The AER rejected the DNSPs' proposed method for deriving the DRP, specifically the use of the Bloomberg's 7 year BBB fair value curve extrapolated to 10 years. The AER considered that both Bloomberg and CBASpectrum should be considered in setting the DRP, and tested the accuracy of fair value curves produced by both data services. Consequently, the AER found CBASpectrum's BBB+ fair value curve provided the best available prediction of observed yields for the purpose of determining the yield on a benchmark BBB+ 10 year corporate bond.

Table 19 AER draft decision on WACC parameters

Parameter	DNSP initial proposals	AER draft decision
Nominal risk-free rate	5.47%	5.65%
Real risk-free rate	2.93 - 3.00%	3.00%
Expected inflation rate	2.40 - 2.47%	2.57%
Gearing level (debt/equity)	60%	60%
Market risk premium	8.0%	6.5%
Equity beta	0.8	0.8
Debt risk premium	4.71%	3.25%
Nominal pre-tax return on debt	7.52 - 7.60%	8.90%
Nominal pre-tax return on equity	11.87%	10.85%
Nominal vanilla WACC	10.86%	9.68%

Victorian DNSP revised regulatory proposals

In their revised regulatory proposals, the Victorian DNSPs:

- did not accept the AER’s justification for the MRP, however, the DNSPs all adopted an MRP value of 6.5 per cent for their revised proposals. The DNSPs submitted a report from Officer and Bishop which again proposed a forward looking MRP of 8 per cent and long term MRP of 7 per cent based on implied volatility and glide path approach

- rejected the AER's methodology and proposed DRP estimate. The DNSPs provided additional consultants report from Competition Economists Group (CEG) and PwC, proposing a different methodology to test whether CBASpectrum or Bloomberg produces the more accurate estimate of the DRP. On the basis of these reports they maintain that Bloomberg's fair value estimates provided the most accurate estimation of the DRP

- accepted the AER draft decision for nominal risk free rate, forecast inflation, equity beta and gearing level.

Table 20 DNSPs revised proposal on WACC parameters

Parameter	DNSP revised proposals
Nominal risk-free rate	5.65%
Real risk-free rate	3.00%
Expected inflation rate	2.57%
Gearing level (debt/equity)	60%
Market risk premium	8.0%
Equity beta	0.8
Debt risk premium	4.28%
Nominal pre-tax return on debt	9.93%
Nominal pre-tax return on equity	10.85%
Nominal vanilla WACC	10.29%

Further consultation on the DRP

On 27 September the AER issued a further consultation paper on the DRP to stakeholders who had specifically commented on WACC related matters. This paper proposed changes to the AER's draft decision in light of the following events:

- CBASpectrum ceasing the publication of its fair value yield curve[1]
- the decision by the Australian Competition Tribunal in the ActewAGL matter (ACT 1 of 2010) handed down on 17 September 2010
- A new 10 year BBB rated bond was issued by the Australia Pipeline Trust (APT).

The AER considered CBASpectrum's decision to no longer publish fair value estimates raises concerns around Bloomberg's fair value estimates. As a result, the AER found it imprudent to solely rely on fair value estimates to derive the DRP.

In addition the Tribunal's rejected the AER's approach for setting the DRP for ActewAGL (which was largely identical to the AER's Victorian draft decision), deciding that the DRP should be calculated by taking the average of CBASpectrum and Bloomberg. In its reason the Tribunal also made suggestions to the AER's approach for future determination citing that a lack of data should encourage the AER to investigate other methods to estimate the DRP.

The AER considered that, prima facie, the APT bond represented a useful benchmark corporate bond rate insofar as the yield calculation is transparent, it reflects a 10 year maturity, and it provides an acceptable proxy for the BBB+ credit rating. The AER

1 As communicated in an email from CBASpectrum to AER staff, 19 August 2010.

also commented that its BBB rating means that its yields would be expected to produce a conservative estimate of the DRP.

In response to the AER's consultation paper, the DNSPs contend that the AER's methodology and use of the APT is not legally permissible under clause 6.5.2(b) and 6.5.2(e) of the NER. The DNSPs further submitted consultant's report that provided an analysis of the APT bond, concluding that the AER's method in using this bond is inappropriate and contend that Bloomberg is still a accurate and a reliable source of data to estimate the benchmark 10 year BBB+ yield.

The AER also received submissions stakeholders highlighting the need for the AER to change it methodology considering that there is a lack of 10 year BBB data currently trading in the market. Furthermore, the submissions have urged the AER to consider the DNSPs' actual cost of debt to estimate the DRP for DNSPs.

AER final decision

The AER considered Officer and Bishop's implied volatility approach to estimate the forward MRP but finds it unpersuasive as Officer and Bishop's implied volatility and glide path approach is subject to various limitations.

The AER notes the downward trend of implied volatility since the height of the GFC. In addition, the AER notes that implied volatility has possibly reverted back to pre-GFC levels. Subsequently, the AER considers it may be appropriate to revert back to the long term historic MRP of 6 per cent based on the current outlook of economic conditions and capital markets. However, the AER is aware that the recovery of global economic conditions is still debatable noting recent comments from prominent economic bodies, warning that recovery in the global economy and conditions in global capital markets remain fragile.

Consequently, the AER remains cautious in its view of global market conditions. Accordingly, under current circumstances the AER is unconvinced that there is persuasive evidence to depart from the SORI MRP of 6.5 per cent. A MRP value of 6.5 per cent will be adopted for the current determination.

In regards to the DRP, the AER has considered the DNSPs arguments and agrees with the weight of evidence that suggests Bloomberg's fair value estimates are still reflective of BBB bond yields with a maturity of less than seven years. Given the characteristics of the APT bond, the AER considers it important to place some weight on the yield of this bond in assessing the DRP. However, the AER also acknowledges that the APT bond is only one observation and hence may not be as accurate as Bloomberg fair value estimates as a proxy of the benchmark BBB corporate bond.

Accordingly the AER has applied its judgement and has given the APT bond a weighting of 25 per cent and Bloomberg 75 per cent which the AER considers to be reasonable given current circumstances.

For averaging periods where there are no observations for the APT bond yield (Jemana's averaging period), the AER will use the first 30 observations of APT bond yields in conjunction with Bloomberg's fair value estimates, applying a ratio of 25 per cent and 75 per cent respectively, to estimate the DRP.

The AER agree with the DNSPs that the appropriate method to extrapolate the Bloomberg's 7 year BBB fair value estimates is to use the difference on AAA fair yields from 7 to 10 years.

Table 21 shows the AER's final decision on the DNSPs' WACC parameters.

Table 21 AER conclusion on WACC parameters

Parameter	CitiPower	Powercor	JEN	SP AusNet	United Energy
Nominal risk-free rate	5.08%	5.08%	5.65%	5.14%	5.08%
Real risk-free rate	2.44%	2.44%	2.99%	2.50%	2.44%
Expected inflation rate	2.57%	2.57%	2.57%	2.57%	2.57%
Gearing level (debt/equity)	60%	60%	60%	60%	60%
Market risk premium	6.5	6.5	6.5	6.5	6.5
Equity beta	0.8	0.8	0.8	0.8	0.8
Debt risk premium	3.74%	3.74%	3.70%	4.05%	3.74%
Nominal pre-tax return on debt	8.81%	8.81%	9.35%	9.19%	8.81%
Nominal post-tax return on equity	10.28%	10.28%	10.85%	10.34%	10.28%
Nominal vanilla WACC	9.40%	9.40%	9.95%	9.65%	9.40%

Corporate income tax and imputation credits

The AER's post-tax revenue model (PTRM) calculates required revenue for each DNSP, from which tax expenses (opex, interest payments on debt and total tax depreciation for all assets) are deducted to arrive at the DNSP's taxable income.

Taxable income is multiplied by the corporate income tax rate, then again by one minus the utilisation of imputation credits (gamma) to arrive at the tax building block for the DNSP. Gamma is calculated as the product of the ‘payout ratio’ (i.e. the proportion of imputation credits generated that are paid out) and the ‘utilisation rate’ or ‘theta’ (i.e. the market value of imputation credits distributed as a portion of their face value).

AER draft decision

The AER considered that the Victorian DNSPs did not present persuasive evidence to depart from the gamma value of 0.65 established in the SORI. Specifically, the AER made the following conclusions about the arguments and reports submitted to it:

- Payout ratio — the AER agreed with the advice it received from its experts (Mackenzie and Partington and Handley) that the true value of the payout ratio is between 70 and 100 per cent.
- Use of tax statistics to estimate theta — the methodology provided by the 2008 Handley and Maheswaran study provides a relevant and reliable estimate of theta in the post 2000 period.
- Use of dividend drop off studies to estimate theta — the AER maintained its reliance on the estimate derived from the Beggs and Skeels study, and continued to consider the alternative Strategic Finance Group (SFG) study was unreliable.

In calculating the tax liability building block, the AER amended the DNSPs' tax roll forward calculations to reflect changes in tax legislation affecting the depreciation of assets held on or after 10 May 2006.

The AER also determined a gradual reduction in the corporate income tax rate over the forthcoming regulatory control period to reflect announcements made by the Commonwealth Government in May 2010 arising out of the Henry Review. Specifically, the AER determined the corporate tax rate would reduce from the current 30 per cent to 29 per cent for the 2013–14 financial year and to 28 per cent from the 2014–15 financial year.

Victorian DNSP revised regulatory proposals

All Victorian DNSPs continued to propose a departure from the 0.65 value of gamma established in the SORI. The following table depicts the values for gamma that Victorian DNSPs submitted in their revised regulatory proposals:

Table 22 Revised proposal gamma values

DNSP	Gamma value
CitiPower	0.5
Powercor	0.5
JEN	0.2
SP AusNet	0.5
United Energy	0.2

Source: Victorian DNSPs' revised regulatory proposals

The Victorian DNSPs argued for relatively lower values of theta and the payout ratio. Specifically, Victorian DNSPs have:

- continued to cite empirical evidence from tax statistics used in existing and new reports in support of a payout ratio less than 100 per cent
- argued that the tax study by Handley and Maheswaran was performed using a contrived data series, and should not be relied upon to estimate theta
- dismissed the AER's concerns in relation to SFG's dividend drop-off study and argued for SFG's study to be considered by the AER to estimate the value of theta
- asserted that the AER has made inconsistent assumptions in estimating the grossed-up value of the MRP and the value of imputation credits as calculated in Beggs and Skeel's dividend drop-off study
- argued that taking an average of the results from tax and dividend drop-off studies to estimate a value of theta is methodologically flawed.

SP AusNet, CitiPower and Powercor argued that the AER should take a balanced approach when recognising these arguments and adopt a gamma value of 0.5.[2] United Energy and JEN recommend the AER adopt a gamma of 0.2, which is based on a 70 per cent payout ratio and a theta value of 0.23.[3]

The DNSPs accepted the AER's draft decision with respect to tax depreciation calculations. SP AusNet, United Energy and JEN rejected the AER's corporate tax rate. While this was accepted by CitiPower and Powercor they also proposed corresponding operational expenditure adjustments arising out of the Government's tax policy announcements.

AER final decision

The AER considers that there is now persuasive evidence justifying a departure from the value of 0.65 established in the SORI in respect of the payout ratio aspect of gamma.

The reasons for this are:

- the true value of the payout ratio is within a range of 70 to 100 per cent
- empirical evidence suggests the average payout ratio is approximately 70 per cent, however there are strong theoretical grounds to suggest that retained credits have some value
- given the material currently available, the AER considers that for the Victorian DNSPs, the theta value of 0.65 is still appropriate in consideration of dividend drop-off and tax studies.

2 CitiPower, Revised regulatory proposal *2011 to 2015*, 21 July 2010, p. 368; Powercor, Revised regulatory proposal *2011 to 2015*, 21 July 2010, p. 359; SP AusNet, *Electricity Distribution Price Review* Revised regulatory proposal , July 2010, p. 331.

3 JEN, Revised regulatory proposal *2011–15*, 20 July 2010, p. 267; United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 211.

- when the two extreme values for the payout ratio (70 per cent and 100 per cent) are combined with a theta of 0.65, the range for gamma becomes 0.465 to 0.65

- given the inherent uncertainty in the estimation of theta, the AER considers that a departure from the gamma value of 0.65 established in the SORI and the adoption of a gamma of 0.5 is justified on the basis of the underlying criteria, in particular the need to provide DNSPs with a reasonable opportunity to recover at least their efficient costs.

The AER accepted the DNSPs' revised proposals in relation to tax depreciation calculations as they are in accordance with clause 11.17.2 of the NER.

As it is possible that further changes will be made to the tax reform package in order to have the enabling legislation passed through parliament, it is uncertain whether or when the proposed reduction to the corporate tax rate will be introduced. In light of this, the AER considers that potential changes to the corporate tax rate cannot reasonably be reflected in the expected statutory corporate income tax rate for the forthcoming regulatory control period. The AER has therefore determined that the current corporate income tax rate of 30 per cent will continue to apply for the forthcoming regulatory control period.

The value of the tax building block for this final decision, as presented in table 23, has also been affected by changes arising from other areas of the AER's final decision, particularly in relation to capital expenditure but various other factors affecting forecast taxable income.

Table 23 AER conclusion on corporate income tax liability ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	6.4	6.8	7.5	7.9	8.5
Powercor	21.8	22.0	23.1	23.9	25.1
JEN	3.0	3.5	4.5	5.6	6.0
SP AusNet	11.0	2.7	4.9	3.9	3.7
United Energy	8.7	9.1	10.1	12.0	13.8

Efficiency carryover amounts for 2006–10

AER draft decision

The draft decision stated that in assessing the Victorian DNSPs' proposed carryover amounts from the 2006–10 regulatory period, the AER considered the following issues:

- application of efficiency carryover amounts to United Energy

- treatment of accrued negative carryover amounts arising from 2001–05 regulatory period for Powercor
- ex post adjustments to the benchmark allowance associated with network growth
- consistency in the measurement of actual expenditure with the ESCV benchmark allowance
- treatment of uncontrollable and non-recurrent costs.

The AER in its draft decision calculated and applied the carryover amounts in its determinations for the Victorian DNSPs as set out in table 24.

Table 24 AER draft decision on the Victorian DNSPs' carryover amounts 2011–15 ($'m, 2010)

	2011	2012	2013	2014	Total
CitiPower	5.5	–6.9	–4.5	–4.7	**–10.6**
Powercor	–	15.6	0.3	–6.2	**9.7**
JEN	20.4	14.5	17.3	2.5	**54.8**
SP AusNet	–3.6	–23.3	–9.2	3.3	**–32.9**

Source: AER, Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015, June 2010, p. 598.

Victorian DNSP revised regulatory proposals

The efficiency carryover amounts arising from the 2006–10 regulatory period, proposed by the Victorian DNSPs to be included in the building block revenue requirements for each DNSP, are summarised in table 25.

Table 25 Victorian DNSPs' revised efficiency carryover amounts 2011–15 ($'m, 2010)

	2011	2012	2013	2014	Total
CitiPower	–	–	–	–	**–**
Powercor	25.9	22.5	1.9	–6.6	**43.7**
JEN	16.8	11.7	13.6	–1.4	**40.7**
SP AusNet	14.6	–23.1	–4.3	3.7	**–9.0**
United Energy	–	–	–	–	**–**

Source: CitiPower, *Revised regulatory proposal*, table 14.3, p. 389; Powercor, *Revised regulatory proposal*, table 14.3, p. 387; JEN, *Revised regulatory proposal*, table 13.3, p. 274; SP AusNet, *Revised regulatory proposal*, table 9.3, p. 290. United Energy, *Revised regulatory proposal*, table 11.4, p. 229.

AER final decision

AER has reviewed the Victorian DNSPs' revised efficiency carryover amounts and made adjustments to the proposed carryover amounts in relation to:

- inclusion of the accrued negative carryover amounts arising from the 2001–05 regulatory period for Powercor
- CitiPower's negative carryovers from the current period will be applied in the forthcoming regulatory control period
- ex post adjustments to the benchmark allowance associated with network growth
- adjustments to the benchmark allowance and actual expenditure to ensure comparability between the benchmark allowance and actual expenditure
- other adjustments
- non-recurrent costs that occur in the base year

The AER has not applied the ECM to United Energy. The AER has applied the ECM for Victorian DNSPs as set out in table 26. This value is used as an input to the Post Tax Revenue Model (PTRM) for the purposes of determining the Victorian DNSPs' annual building block revenue requirement during the 2011–15 regulatory control period. Chapter 13 contains the AER's final decision on Victorian DNSPs' proposed carryover amounts.

Table 26 AER conclusion on the Victorian DNSPs' carryover amounts 2011–15 ($'m, 2010)

	2011	2012	2013	2014	Total
CitiPower	4.4	–8.0	–5.7	–4.9	**–14.3**
Powercor	–	1.2	–9.7	–13.1	**–21.7**
JEN	19.9	13.9	15.6	–0.6	**48.7**
SP AusNet	11.1	–23.6	–8.6	1.8	**–19.4**

Efficiency benefit sharing scheme

AER draft decision

The AER's draft decision applied the EBSS in accordance with the framework and approach paper for the Victorian DNSPs.

The AER noted that forecast opex will be adjusted for the actual growth in line length, the number of distribution transformers and zone substations, and customer numbers experienced over the forthcoming regulatory control period, using the network growth escalation method in appendix J.

The following would be excluded from the calculation of EBSS carryover amounts:

- superannuation costs for defined benefits and retirement schemes
- the DMIA
- debt raising costs
- self insurance costs
- GSL payments.

Chapter 14 of the draft decision set out the AER’s draft concussions on the application of the EBSS to Victorian DNSPs.

Victorian DNSP revised regulatory proposals

Between them, the Victorian DNSPs proposed the following additional excluded costs categories from the EBSS:

- costs arising from the transfer of non-price distribution regulatory arrangements to a national regulatory framework
- costs arising from changes to safety regulations introduced by Energy Safe Victoria
- costs arising from the financial failure of a retailer event
- costs arising from changes in exposure limits introduced as part the radiation protection standard for exposure limits to magnetic fields 0Hz, by the Australian Radiation Protection and Nuclear Safety Agency
- fees or charges payable to the Australian Energy Market Operator
- costs arising from recommendation of the Victorian Bushfires Royal Commission
- costs arising from an emissions trading scheme
- a natural disaster event
- an insurance event/legal liability above insurance cap event
- an insurer credit risk event.
- new tariff assignment dispute resolution costs
- Energy Safe Victoria fees
- Ombudsman scheme costs
- costs associated with high voltage injection claims

- superannuation
- changes in classification of a service
- adjustments for changes in regulatory responsibilities
- proposed nominated pass through events not determined by the AER to be pass through events
- expenditure that meets all of the necessary requirements for an approved pass through event other than satisfying the materiality threshold.
- United Energy also proposed amendments to the EBSS formula.

AER final decision

The AER's final decision will apply the EBSS in accordance with the framework and approach paper.

Consistent with the methodology in appendix J, when assessing EBSS carryover amounts to apply in 2016–20, the AER will substitute actual values for customer numbers, the number of distribution transformers and zone substation capacity MVA and line length for the years 2011–14 and a revised forecast for 2015, for the forecasts of these metrics used in this final decision.

The AER concludes that the following will be excluded from calculation of EBSS carryover amount for the forthcoming regulatory period:

- superannuation costs for defined benefits schemes
- DMIA expenditure
- expenditure on non-network alternatives
- recognised pass through events and recognised regulatory change events or service standard events. However the AER clarifies that.
- debt raising costs
- self insurance costs
- GSL payments.

Events which appear to be regulatory change events or service standard events, but do not meet the pass through materiality threshold in the NER will not be excluded from the reported opex when calculating EBSS carryover amounts.

The controllable opex for each Victorian DNSP is set out in chapter 14 of the final decision.

Service target performance incentive scheme

The STPIS provides financial incentives for DNSPs to maintain and improve service performance. This balances the incentive in the regulatory framework for DNSPs to reduce costs at the expense of service quality. Cost reductions are beneficial to both DNSPs and their customers when service performance is maintained or improved. However, cost efficiencies achieved at the expense of service performance are not desirable.

The STPIS establishes targets based on historical performance, and provides financial rewards for DNSPs beating performance targets and financial penalties for DNSPs failing to meet targets. The STPIS has two components, the S factor and the guaranteed service levels (GSL) scheme:

- The S factor component adjusts the revenue that a DNSP earns depending on reliability of supply and customer service performance.

- The GSL scheme sets threshold levels of service for DNSPs to achieve, and requires direct payments to customers who experience service worse than the predetermined level. The national GSL scheme under the STPIS does not apply in a jurisdiction, if a jurisdictional GSL scheme is in existence.

AER draft decision

Section 15.3 provides a summary of the AER's draft decision. Having taken into account the Victorian DNSPs' revised regulatory proposals and stakeholder submissions, the AER has made a final decision regarding the application of the STPIS, which is largely unchanged from the draft decision. Key areas where the final decision differs substantially from the draft decision are set out below.

Victorian DNSP revised regulatory proposals

The Victorian DNSPs adopted most aspects of the AER's application of the STPIS. The key points of contention in each Victorian DNSP's revised regulatory proposal are as follows:

- Both CitiPower and Powercor submitted that the S factor close out term should be added to the control mechanism. They also proposed that their underlying performance for the purpose of the close out of the ESCV S factor scheme should be set at the 2005–09 average reliability performance. [4]

- JEN submitted that:

  - The AER's proposal for a final true up adjustment to the 2016–20 building block revenue requirement at the 2015 price review does not adequately address its concerns regarding fair and accurate true up for the transition to the STPIS. JEN proposed that the best solution is an adjustment to 2013 tariffs. [5]

  - JEN understands the AER's interpretation of the calculation of the MED threshold and in general supports this position as reflective of the intent of the

4 CitiPower, *Revised regulatory proposal*, p. 398; Powercor, *Revised regulatory proposal*, p. 396.
5 JEN, *Revised regulatory proposal*, p. 23.

scheme. JEN requested that the AER amend the STPIS to more clearly reflect the AER's interpretation. Otherwise, JEN proposed that its interpretation should be adopted.[6]

- SP AusNet submitted that:
  - SP AusNet welcomed the AER's draft decision to change the MED threshold from 2.5 beta to 2.8 beta from the mean, but again proposed a threshold of 3.2 beta from the mean because:
    - there is no significant distinction between 2.8 and 3.2 beta from an asset management perspective
    - events smaller than 3.2 beta are within SP AusNet's control, hence there will be a perverse incentive to not respond to such events
    - a higher beta will reduce volatility in performance as action will be taken to reduce infrequent, large events.[7]
  - It disagreed with the draft decision to not exclude supply interruptions due to demand management schemes.[8]
  - The AER misunderstood its climate change analysis. It re-submitted a revised climate change adjustment model.
  - SP AusNet also proposed a variation to clause 3.3 of the STPIS to include an additional exclusion event for supply interruption due to the suppression of auto reclose devices in high bushfire risk areas.[9]
- United Energy submitted that there was no objectively correct mechanism for closing out the ESCV S factor scheme. Therefore, it proposed that the scheme not proceed from 31 December 2010 and that no close out amount be included in the building blocks for the 2011–15 regulatory control period. It also contended that the AER's draft decision was inconsistent with the National Electricity Objective because efficient investment to improve network reliability cannot be achieved if random or arbitrary penalties are imposed unexpectedly on businesses. It believes that the appropriate way to close out the ESCV S factor scheme is through the price control formula.[10]

AER final decision

The AER changed from its draft decision in the following areas.

Close out of the ESCV S factor scheme

Based on submissions received, the AER has modified the assumption of ongoing performance used to close out the ESCV S factor scheme. In its draft decision, the AER assumed ongoing performance would be equal to a DNSP's performance in

6 ibid, p. 283, 284.
7 SP AusNet, *Revised regulatory proposal*, p. 35–43.
8 ibid., p. 43, 44.
9 ibid., p. 48.
10 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 217–221.

2010. In this final decision, the AER has concluded that the appropriate assumption regarding ongoing performance is to use the average of 2005–10 performance, as measured under the ESCV S factor scheme. The AER considers that this assumption provides for a more accurate result for closing out of the ESCV S factor scheme.

Proposed bushfire related exclusion criteria

The AER considers that avoidable supply interruptions due to the suppression of the auto-recloser system under an approved Electricity Safety Management Scheme would meet the exclusion criteria under clause 3.3(a)(7) of the STPIS. In order to ensure that there is no windfall gain, resulting from excluding these supply interruptions, the AER will adjust SP AusNet's MAIFI target down by the amounts outlined in table 15.14 for the 2011–15 regulatory control period.

Performance targets

The performance targets for the Victorian DNSPs, with the exception of SP AusNet, are unchanged from the draft decision. SP AusNet identified some inaccuracies in the calculations it provided to the AER at the time of the draft decision.

Calculation of incentive rates

As foreshadowed in the draft decision the incentive rates for the STPIS have been updated to reflect the growth forecasts approved in the final decision. Additionally, the manner in which the Value of Customer Reliability has been inflated with CPI has been altered to more closely reflect the final decision on the AER's STPIS.

The AER will apply the national STPIS, with the exception of the existing jurisdictional GSL scheme, to the Victorian DNSPs in the forthcoming regulatory control period. The AER's final decision on the application of the STPIS is as follows:

- The AER will apply the SAIDI, SAIFI and MAIFI parameters to the Victorian DNSPs, segmented by network types as set out in the STPIS. For transitional reasons, the AER will apply the ESCV definition of MAIFI discussed at section 15.6.12 of this final decision.

- The AER will apply the telephone answering customer service parameter to the Victorian DNSPs. For all Victorian DNSPs the AER will apply the default cap on revenue at risk, of 0.5 per cent, to the telephone answering customer service parameter.

- The AER will apply the following caps on revenue at risk for the Victorian DNSPs:

  - CitiPower ± 5 %
  - Powercor ± 5 %
  - JEN ± 5 %
  - SP AusNet ± 7 %
  - United Energy ± 5 %

- The AER has determined the following MED threshold to apply to the Victoria DNSPs, in the first year of the 2011–15 regulatory period:
  - CitiPower 2.5 beta from the mean
  - Powercor 2.8 beta from the mean
  - JEN 2.5 beta from the mean
  - SP AusNet 2.8 beta from the mean
  - United Energy 2.5 beta from the mean
- The incentive rates to apply to each applicable parameter are set out in table 15.13 of this final decision.
- The AER will apply the jurisdictional GSL scheme to the Victorian DNSPs as set out in section 15.6.16.
- The AER has developed a methodology to close out the ESCV S factor scheme, by replicating the intended benefits or penalties accrued under the scheme. In the 2016–20 distribution determination, the AER will perform a final reconciliation to account for actual 2010 performance under the ESCV S factor scheme. The methodology used to close out the ESCV S factor scheme is set out in section 15.6.6.

Pass through arrangements

AER draft decision

The Victorian DNSPs initially proposed a total of 26 nominated pass through events. The AER draft decision nominated the following four pass through events for the Victorian DNSPs:

- a declared retailer of last resort
- insurer credit risk
- insurance event (this replaces SP AusNet's legal liability above insurance cap event)
- a natural disaster event.

For these events, the AER's draft decision set out a materiality threshold of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

The AER rejected several events on the grounds that they did not meet assessment criteria for nominated pass through events.[11] Other events (for example, the emissions trading scheme event, VBRC event, and transfer to national customer framework event) were rejected on the grounds that they would likely fall within the NER prescribed pass through events.[12] The AER also rejected the general nominated pass through event, which it had included in previous distribution determinations.

Victorian DNSP revised regulatory proposals

The Victorian DNSPs generally disagreed with the AER's draft decision on pass throughs. In particular, they stated:

- that the AER's materiality threshold was too high[13]
- that the AER should not have rejected the general nominated pass through events and the financial failure of a retailer event. JEN also stated that the AER should not have rejected its asbestos compensation event or its force majeure event
- for the events that were rejected on the grounds that they would likely fall within the NER prescribed events, the AER should either confirm that these would definitely fall within the NER events, or nominate them in the distribution determination.
- SP AusNet and JEN both raised concerns with the AER's amendments to the definition of insurance event. SP AusNet also raised concerns with the AER's definition of insurer credit risk event.

AER final decision

The AER, in its final decision, has maintained the one percent materiality threshold for NER prescribed events. The AER also maintained its list of nominated pass through events, as per the draft decision.

- a insurance event
- an insurer credit risk event
- a natural disaster event
- a declared retailer of last resort event
- a network charge pass through event.

However, the AER:

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[11] The assessment criteria can be found at chapter 16 of this final decision. A full discussion of the AER's considerations in developing that set of criteria can be found at chapter 16 of the draft decision.

[12] These are a regulatory change event, service standard event, tax change event and terrorism event.

[13] JEN further submitted the AER had no power under the NER to set a materiality threshold in the distribution determination.

- amended its definitions of both the insurer credit risk event, and the insurance event
- confirmed that certain events would fall within the NER prescribed pass through events.

Demand management incentive scheme

AER draft decision

The AER's draft decision on the DMIS was to apply both the DMIA and the forgone revenue component of the DMIS to the Victorian DNSPs. The AER rejected United Energy’s submission to increase the DMIA.

The annual capped amount under the DMIA for each Victorian DNSP for the forthcoming regulatory control period was:

- $200 000 for JEN and CitiPower ($1 million over the regulatory control period)
- $400 000 for United Energy ($2 million over the regulatory control period)
- $600 000 for Powercor and SP AusNet ($3 million over the regulatory control period)

Victorian DNSP revised regulatory proposals

The Victorian DNSPs largely accepted the AER's draft decision on the DMIS. United Energy sought to clarify that the additional demand management expenditure proposed in its initial regulatory proposal was intended as opex step changes, rather than an expansion of the DMIS.

AER final decision

The AER's final decision is to maintain the draft decision on the application of the DMIS, as set out above.

Overall revenue requirements and X factors

AER draft decision

The draft decision did not accept the building block revenue requirement proposals by the Victorian DNSPs. The AER calculated each Victorian DNSP's annual revenue requirement and X factors using the PTRM and the AER's substituted amounts (as approved in relevant chapters of its draft decision) on:

- asset base roll forward and indexation
- return on capital
- depreciation and estimated tax payable
- operating and maintenance expenditure

- revenue decrements arising from previous regulatory periods' control mechanisms.

The AER's draft decisions on the revenue requirements and X factors for each Victorian DNSP are set out in tables 27 to 31.

Table 27 AER draft decision on revenue requirements and X factors ($'m, nominal)—CitiPower

	2010	2011	2012	2013	2014	2015
Return on capital		124.5	133.8	142.6	152.0	158.6
Regulatory depreciation		35.2	38.4	41.9	45.6	49.6
Operating expenditure		36.7	37.7	39.5	42.0	43.4
Carryover amounts		5.8	–10.2	–8.5	–5.4	–7.8
Tax allowance		6.0	6.3	6.6	6.6	6.8
Annual revenue requirements		208.2	206.0	222.0	240.8	250.6
Expected revenues	211.8	205.0	215.1	223.2	234.7	248.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		7.27	–	–	–2.00	–2.00

Note: Positive values for X indicate real price decreases under the CPI-X formula

Table 28 AER draft decision on revenue requirements and X factors ($'m, nominal)—Powercor

	2010	2011	2012	2013	2014	2015
Return on capital		213.4	227.2	241.4	255.9	271.0
Regulatory depreciation		62.0	68.1	74.6	81.5	88.9
Operating expenditure		123.0	127.5	133.1	141.9	147.2
Carryover amounts		16.7	8.5	–4.5	–6.0	–32.6
Tax allowance		7.7	8.6	9.2	9.8	10.6
Annual revenue requirements		422.7	439.8	453.8	483.3	485.0
Expected revenues	426.7	413.1	434.8	458.3	481.3	502.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		8.14	–	–	–	–

Note: Positive values for X indicate real price decreases under the CPI-X formula

Table 29 AER draft decision on revenue requirements and X factors ($'m, nominal)—JEN

	2010	2011	2012	2013	2014	2015
Return on capital		71.8	75.0	78.4	81.9	85.3
Regulatory depreciation		26.9	30.7	34.7	39.0	32.3
Operating expenditure		48.9	50.4	52.2	57.0	57.9
Carryover amounts		18.7	15.5	19.5	3.6	0.4
Tax allowance		2.3	2.8	3.3	3.7	3.0
Annual revenue requirements		168.7	174.4	188.1	185.2	178.9
Expected revenues	166.0	165.9	174.7	184.2	187.7	184.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		1.46	–	–	3.00	6.00

Note: Positive values for X indicate real price decreases under the CPI-X formula

Table 30 AER draft decision on revenue requirements and X factors ($'m, nominal)—SP AusNet

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		202.7	212.3	226.9	242.0	258.6
Return on capital		90.9	47.3	53.8	49.3	40.1
Operating expenditure		133.7	138.5	144.6	151.6	157.7
Carryover amounts		16.8	–22.1	–15.5	4.5	–53.1
Tax allowance		8.2	3.5	4.4	4.3	3.8
Annual revenue requirements		452.2	379.4	414.2	451.7	407.1
Expected revenues	379.5	382.2	400.1	422.1	448.7	475.1
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		4.46	–	–	–	–

Note: Positive values for X indicate real price decreases under the CPI-X formula

Table 31 AER draft decision on revenue requirements and X factors ($'m, nominal)—United Energy

	2010	2011	2012	2013	2014	2015
Return on capital		134.3	142.2	149.4	155.6	161.8
Regulatory depreciation		36.0	42.7	50.2	57.9	66.2
Operating expenditure		92.9	95.8	99.7	105.6	108.9
Carryover amounts		–5.1	–19.8	–19.2	–20.1	–47.6
Tax allowance		4.8	5.6	6.7	7.2	7.8
Annual revenue requirements		262.9	266.6	286.8	306.2	297.0
Expected revenues	296.2	249.5	262.1	281.0	303.5	332.2
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		19.57	–	–2.00	–3.00	–5.00

Note: Positive values for X indicate real price decreases under the CPI-X formula

Victorian DNSP revised regulatory proposals

In their revised regulatory proposals, the Victorian DNSPs did not accept the AER’s draft decision on their revenue requirements and X factors because they did not accept the AER's draft decisions on the respective components of the building block model

Table 32 to 36 summarise the Victorian DNSPs' revised regulatory proposals on their revenue requirements and X factors.

Table 32 Revised regulatory proposal on revenue requirements and X factors ($'m, nominal)—CitiPower

	2011	2012	2013	2014	2015
Return on capital	132.6	148.6	165.6	184.7	203.4
Regulatory depreciation	34.8	38.6	42.7	46.9	52.4
Operating expenditure	52.7	54.4	57.6	59.1	63.4
Efficiency carryover amounts	–	–	–	–	–
S-factor amounts	0.2	–2.9	–3.4	–0.2	–7.3
Tax allowance	4.2	4.6	5.5	5.9	6.9
Annual revenue requirement	224.4	243.4	267.9	296.4	318.7
X factor (per cent)	–7.27	–4.00	–4.00	–4.00	–4.00

Source: CitiPower, *Revised regulatory proposal*, pp. 427–428.

Table 33 Revised regulatory proposal on revenue requirements and X factors ($'m, nominal)—Powercor

	2011	2012	2013	2014	2015
Return on capital	228.0	255.0	283.3	312.1	342.2
Regulatory depreciation	62.2	70.6	79.3	88.2	99.8
Operating expenditure	180.1	190.2	197.0	210.7	224.0
Efficiency carryover amounts	26.6	23.7	2.1	–7.4	–
S-factor amounts	8.3	–6.8	–3.6	1.7	–19.3
Tax allowance	3.9	4.8	6.0	7.2	9.0
Annual revenue requirement	509.1	537.5	564.1	612.5	655.7
X factor (per cent)	–20.63	–1.00	–1.00	–1.00	–1.00

Source: Powercor, *Revised regulatory proposal*, pp. 428–429.

Table 34 Revised regulatory proposal on revenue requirements and X factors ($'m, nominal)—JEN

	2011	2012	2013	2014	2015
Return on capital	78.9	88.6	99.3	108.4	116.5
Regulatory depreciation	27.0	32.9	39.5	45.4	45.5
Operating expenditure	70.2	69.6	71.3	78.9	86.4
Efficiency carryover amounts	15.0	11.4	14.2	–2.1	–3.1
S factor true-up	–2.2	–0.9	–0.4	–0.4	–2.8
Tax allowance	2.0	2.7	3.7	5.4	5.4
Annual revenue requirement	190.9	204.3	227.5	235.5	247.9
X factor (per cent)	–6.41	–3.00	–3.00	–3.00	–3.00

Source: JEN, *Revised regulatory proposal*, pp. 315–316.

Table 35 Revised regulatory proposal on revenue requirements and X factors ($'m, nominal)—SP AusNet

	2011	2012	2013	2014	2015
Return on capital	214.1	236.0	266.5	296.7	324.8
Regulatory depreciation	91.9	51.2	62.2	58.2	55.9
Operating expenditure	187.6	200.5	213.5	226.1	237.4
Efficiency carryover amounts	15.0	–24.3	–4.6	4.1	–
S-factor amounts	20.0	2.4	–5.2	0.8	–46.7
Tax allowance	6.0	–	–	–	–
Annual revenue requirement	534.5	465.8	532.4	586.0	571.4
X factor (per cent)	–25.08	–1.9	–1.9	–1.9	–1.9

Source: SP AusNet, *Revised regulatory proposal*, pp. 363–365.

Table 36 Revised regulatory proposal on revenue requirements and X factors ($'m, nominal)—United Energy

	2011	2012	2013	2014	2015
Return on capital	142.9	159.5	175.6	189.7	199.3
Depreciation	41.4	49.7	60.8	71.2	79.5
Operating expenditure	135.3	135.0	136.3	139.1	142.3
Efficiency carry-over amounts	–	–	–	–	–
Tax allowance	11.0	12.8	16.2	21.0	25.6
Annual revenue requirement	330.6	357.0	388.9	421.1	446.6
X factor (per cent)	–16.83	–4.0	–4.0	–4.0	–4.0

Source: United Energy PTRM.

AER final decision

The AER's final decision is in accordance with clause 6.12.1(2) of the NER. The AER has calculated each Victorian DNSP’s revenue requirements and X factors based on its final decisions on:

- asset base roll forward and indexation
- return on capital
- depreciation and estimated tax payable
- operating and maintenance expenditure

- revenue decrements arising from previous regulatory periods' control mechanisms.

The main reasons for the increases relative to the AER's draft decision are due to positive adjustments to the RAB (due to increased amounts for capital expenditure) and operating and maintenance expenditures. A further contributor to price increases relative to the draft decision is the AER's acceptance of slowing energy sales growth, which reflects the DNSPs' updated modelling assumptions for population growth and also the recognition of a moderate impact of time of use tariffs.

This final decision approves the amounts as set out in table 37 to 41 below.

Table 37 AER conclusion on revenue requirements and X factors ($'m, nominal)—CitiPower

	2010	2011	2012	2013	2014	2015
Return on capital		121.0	132.3	143.5	156.3	168.9
Regulatory depreciation		34.7	38.4	42.3	46.5	51.8
Operating expenditure		46.3	47.6	50.1	50.8	53.3
Efficiency carryover amounts		4.5	–8.4	–6.2	–5.5	–
S factor amounts		–2.2	–4.7	–3.6	–0.4	–4.0
Tax allowance		6.3	6.7	7.4	7.7	8.4
Annual revenue requirements		210.6	211.8	233.5	255.4	278.5
Expected revenues	213.3	205.8	221.0	235.3	252.8	273.9
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		6.41	–4.00	–4.00	–5.00	–5.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

Table 38 AER conclusion on revenue requirements and X factors ($'m, nominal)—Powercor

	2010	2011	2012	2013	2014	2015
Return on capital		208.0	227.7	247.1	267.2	288.8
Regulatory depreciation		62.1	69.9	77.9	86.3	96.8
Operating expenditure		160.9	167.8	169.9	179.3	188.2
Efficiency carryover amounts		–	1.2	–10.4	–14.5	–
S factor amounts		–6.1	–22.0	–5.6	–0.3	0.9
Tax allowance		12.5	12.9	14.1	15.0	16.4
Annual revenue requirements		437.4	457.4	492.9	532.9	591.1
Expected revenues	422.2	440.7	470.0	497.4	529.0	568.8
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–0.11	–3.00	–3.00	–3.50	–4.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

Table 39 AER conclusion on revenue requirements and X factors ($'m, nominal)—JEN

	2010	2011	2012	2013	2014	2015
Return on capital		75.2	80.8	87.1	93.2	99.6
Regulatory depreciation		26.6	31.7	37.7	43.0	42.9
Operating expenditure		57.5	57.8	59.4	66.4	67.0
Efficiency carryover amounts		20.4	14.6	16.9	–0.7	–
S factor amounts		5.6	1.0	–0.2	–0.2	–11.1
Tax allowance		2.9	3.4	4.4	5.5	5.9
Annual revenue requirements		188.2	189.3	205.3	207.2	204.3
Expected revenues	168.8	179.8	190.1	199.3	209.1	220.8
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–4.99	–3.00	–3.00	–3.00	–3.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

Table 40 AER conclusion on revenue requirements and X factors ($'m, nominal)—SP AusNet

	2010	2011	2012	2013	2014	2015
Return on capital		200.2	219.9	244.6	270.0	295.7
Regulatory depreciation		91.1	51.2	62.3	58.1	55.1
Operating expenditure		162.9	174.2	184.9	199.2	207.1
Efficiency carryover amounts		11.4	–24.9	–9.3	2.0	–
S factor amounts		41.3	21.3	–7.6	–1.8	–89.6
Tax allowance		11.1	2.9	5.1	4.2	3.9
Annual revenue requirements		518.0	444.5	480.0	531.7	472.3
Expected revenues	373.9	430.0	458.4	488.4	528.1	575.0
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–9.99	–4.00	–4.00	–5.00	–5.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM

Table 41 AER conclusion on revenue requirements and X factors ($'m, nominal)—United Energy

	2010	2011	2012	2013	2014	2015
Return on capital		129.7	142.7	155.6	165.2	173.1
Regulatory depreciation		41.0	49.1	59.9	70.1	78.0
Operating expenditure		108.6	113.6	117.2	124.9	129.8
Efficiency carryover amounts		–	–	–	–	–
S factor amounts		–4.9	–5.1	–6.7	–6.8	–12.3
Tax allowance		8.5	8.8	9.8	11.7	13.5
Annual revenue requirements		282.9	309.2	335.8	365.0	382.1
Expected revenues	291.8	301.9	313.6	324.5	349.5	379.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–0.37	–1.00	–2.00	–6.00	–6.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM

Public Lighting

AER draft decision

The AER reviewed the Victorian DNSPs' forecast opex and capex over the 2011–15 regulatory control period in assessing the efficient costs of providing public lighting services. The AER also assessed each DNSPs' proposed opex and capex inputs, including the costs and forecast volumes of luminaires, poles and brackets to be replaced.

The AER's draft decision rejected the Victorian DNSPs' proposed public lighting charges for 2011–15 on the basis that their opex and capex inputs did not represent the efficient costs of providing public lighting services. The AER also rejected the DNSPs' proposed WACC and SP AusNet and United Energy's forecast capex replacement volumes.

Victorian DNSP revised regulatory proposals

The Victorian DNSPs accepted the AER's draft decision on some cost inputs but rejected the AER's view on several opex and capex inputs, particularly the costs of labour, patrol and elevated platform vehicles, and other public lighting costs. Some DNSPs also submitted revised labour and material cost escalation rates as well as revised failure rates of MV80 and T5 luminaires.

However, not all the Victorian DNSPs contested the same inputs, and variations in costs were often proposed for the same inputs, such as patrol vehicle costs and luminaire costs.

AER final decision

In assessing the Victorian DNSPs' revised proposals and public lighting inputs, the AER accepted revised costs of vehicles and public lighting materials such as luminaires, poles and brackets. The AER considered that these were substantiated by reasonable evidence and documentation.

The AER accepted higher labour rates for some DNSPs which was consistent with the recommendations received from the AER's consultant, Impaq Consulting. The AER also determined that it was appropriate to apply materials cost escalation to public lighting materials (other than poles and brackets), as this was consistent with the AER's approach to other alternative control services and standard control services.

However, the AER's final decision rejected the DNSPs' proposed annual failure rates of T5 luminaires and traffic management costs, as these were not substantiated by reasonable evidence. The AER also considered that these were not representative of the efficient costs of providing public lighting services.

Other alternative control services

AER draft decision

In the draft decision, the AER largely rejected CitiPower's, Powercor's and JEN's proposed prices for fee based services and labour rates for quoted services over the 2011-15 regulatory control period, based on analysis of their labour rates and times within cost build ups for each service. The AER also rejected the DNSPs' proposed profit margins within alternative control services, and applied its own 3 per cent margin to provide a reward for past efficiencies.

The draft decision largely approved the prices proposed by SP AusNet and United Energy, with the exception of the use of cost escalators and inflation above contractor prices, respectively.

The 2011 prices and labour rates for fee based and quoted services approved by the AER in the draft decision drew upon the advice provided by the AER's consultant, Impaq Consulting (Impaq), specifically, the appropriate labour charge out rates and times taken to perform each service. A public version of Impaq's final report was released with the AER's draft decision.

The AER's draft decisions on the Victorian DNSPs' fee based and quoted services prices for 2011 were set out in appendix O of the draft decision. The draft decision stated that compliance with the alternative control services control mechanisms would be demonstrated through an annual pricing proposal process.

Victorian DNSP revised regulatory proposals

CitiPower and Powercor stated that the AER's draft decision prices would not allow for the recovery of the efficient costs of providing fee based alternative control services.[14] CitiPower and Powercor proposed new prices for fee based alternative control services, based on their own internal and contract labour rates, times taken to perform services and profit margins. CitiPower and Powercor raised arguments in relation to the draft decisions on profit margins, contract rates, non-chargeable time and times taken for certain activities.

JEN's revised regulatory proposal raised issues regarding the draft decision on alternative control services profit margins, hourly rates for line workers, after hours rates for line workers, scheduler hourly rates, times taken to perform back office functions, wasted service vehicle visits, contract rates for meter equipment test services, tax liabilities for routine connection services, reserve feeder charges, temporary supply services.[15]

SP AusNet's revised regulatory proposal largely accepted the AER's draft decision for fee based alternative control services. However, SP AusNet raised issues regarding the inclusion of Access Economics' revised labour escalators; the draft decision fee for Multi Phase Overhead—CT connected meter—After hours; the draft decision fee for Overhead supply—Coincident Disconnection (Truck visit)—After hours.[16]

United Energy's revised regulatory proposal largely accepted the AER's draft decision on its fee based alternative control services charges for 2011. However, it raised concerns regarding the AER's rejection of its proposed charges for meter data services for customers consuming more than 160MWh per annum.[17] United Energy submitted

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[14] CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 433; Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 434.

[15] JEN, *Revised regulatory proposal*, pp. 327–347.

[16] SP AusNet, *Electricity Distribution Price Review, Revised Regulatory Proposal*, July 2010, p. 388.

[17] United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 339.

revised proposed charges for the services which the AER identified as being arbitrarily inflated above the winning bidder prices, following further negotiation with its winning bidder.[18]

AER final decision

The AER’s final decision on the Victorian DNSPs’ fee based and quoted services prices for 2011 is set out in appendix Q of this final decision. The AER's final decision is that compliance with the alternative control services control mechanisms will be demonstrated through an annual pricing proposal process, described in detail in chapter 20.

CitiPower and Powercor

In making its decision on the form of control for alternative control services for the 2011-15 regulatory control period, the AER rejects CitiPower's and Powercor's revised proposed 2011 prices for fee based alternative control services, aside from its proposed reserve feeder service fee. The AER accepts CitiPower's and Powercor's proposed prices for reserve feeder services for 2011–15.

In approving all other fee based alternative control service 2011 prices for this final decision, the AER has:

- applied the highest point of the range of revised labour rates recommended by Impaq, adjusted to incorporate vehicle costs and a 3 per cent margin above overheads
- revised the times taken to perform tasks consistent with Impaq's revised advice.

The AER rejects CitiPower's and Powercor's proposed hourly labour rates for quoted services as they are above the benchmark industry rates recommended by Impaq.

The AER rejects CitiPower's and Powercor's proposed X factors for fee based and quoted alternative control services, and instead approves X factors which incorporate the AER's final decision on cost escalators.

JEN

The AER rejects JEN's revised proposed 2011 prices for fee based alternative control services. In approving JEN's fee based alternative control service prices for 2011, the AER has:

- applied the highest point of the range of revised labour rates recommended by Impaq, adjusted to incorporate a 3 per cent margin above overheads
- revised the times taken to perform tasks consistent with Impaq's revised advice.

The AER rejects JEN's proposal for increases in the after hours rate and scheduler hourly rate, and also rejects JEN's proposed reserve feeder charge.

[18] ibid., p. 339.

The AER accepts JEN's proposed Formway contract rate for meter equipment test services and also accepts JEN's proposal for a 7 per cent mark up on routine connection services as a result of JEN's capitalisation of routine connection assets.

The AER accepts JEN's proposed quoted services hourly labour rates for 2011.

The AER rejects JEN's proposed X factors for fee based and quoted alternative control services, and considers that it is appropriate to apply X factors that incorporate cost escalators that are equal to those approved for standard control services. The AER's final decision on JEN's X factors is set out in appendix Q.

SP AusNet

The AER rejects SP AusNet's revised proposed prices for fee based alternative control services. The AER's final decision prices for SP AusNet incorporate the AER's final decisions on cost escalators for standard control services. The approved price for Overhead Supply—Coincident Disconnection (truck visits)—after hours is based on a cost build up using Impaq's revised advice on times and labour rates.

The draft decision accepted SP AusNet's proposed price path for fee based alternative control services, and accordingly the AER maintains its draft decision on SP AusNet's price path for alternative control services.

The AER affirms its draft decision prices for SP AusNet's business hours quoted alternative control services labour rates for 2011, set out in appendix Q. The AER approves SP AusNet's proposed after hours rates for quoted alternative control services, which will be escalated by the approved outsourced labour escalators.

United Energy

The AER accepts United Energy's revised proposed prices for its fee based alternative control services, aside from its proposed charge for meter data services for customers consuming more than 160MWh per annum with a manually read meter. The AER has not set charges for this meter data service as it is a contestable service and is not classified in this final decision. The draft decision accepted United Energy's proposed price path for fee based alternative control services and accordingly the AER affirms its draft decision on United Energy's price path for fee based alternative control services as the final decision.

The AER accepts United Energy's proposed hourly labour rates for quoted services. Consistent with the AER's draft decision, United Energy's labour rates will be escalated over 2012–15 by the AER's approved outsourced labour escalation rate for standard control services.

Outcomes monitoring and compliance

The AER is establishing a framework to monitor the outcomes of the 2011–15 Victorian distribution determinations, and the Victorian DNSPs' service levels delivered to their customers.

It is intended that the monitoring framework will include both financial and customer service measures. The financial measures will include measurements of the effectiveness of opex and capex expenditure through a number of monitoring and performance measures, as well as physical volumes of assets such as the number of new connections. The AER also intends to coordinate with Energy Safe Victoria in monitoring DNSPs' cost and activities arising from safety related capex and opex expenditures.

The customer service outcome measures will include the traditional performance indicators in quality and reliability of supply, providing timely service to customers; as well as the monitoring of low supply reliability areas, and DNSPs’ performance in responding to major network events.

The AER will undertake specific consultation with relevant stakeholders to determine the format in which the AER will be collecting the outcome measures. Chapter 21 outlines the outcomes monitoring framework that the AER is implementing in the forthcoming regulatory control period.

1 Introduction

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the AER is responsible for the economic regulation of electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market (NEM).

In Victoria, the DNSPs are CitiPower, Powercor, Jemena Electricity Networks (JEN), SP AusNet and United Energy Distribution (United Energy). The economic regulation of DNSPs involves, amongst other things, undertaking a distribution determination. In making that determination, the AER must follow chapter 6 of the NER, which sets out the framework for the economic regulation of the distribution network.

This is the first electricity distribution determination made by the AER for CitiPower, Powercor, JEN, SP AusNet and United Energy. The previous price review that applied to these Victorian DNSPs was made by the Essential Services Commission of Victoria (ESCV), from 2006–2010. This price review expires on 31 December 2010. On 1 January 2011, the AER's distribution determinations will take effect. The AER's final decision on those distribution determinations is set out in this document. The AER's distribution determination for each individual DNSP can be found on the AER's website. The determination documents contain the outcomes of the review process—that is, the final decision only. This decision document, however, provides the AER's considerations and conclusions on the DNSPs' revised regulatory proposals.

In making its final decision and distribution determinations, the AER has taken into account the Victorian DNSPs' revised regulatory proposals, submissions from interested parties, advice from consultants and updated economic information and forecasts.

Further explanation of the AER’s decisions and the context in which they were made is provided below, and in greater detail through the chapters of this decision.

1.1.1 National Electricity Law

The NEL sets out the functions and powers of the AER, including its role as the economic regulator of utilities operating in the NEM. Section 16 of the NEL states that when performing or exercising a regulatory function or power, the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective.

The national electricity objective is:[1]

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to–
>
> (a) price, quality, safety, reliability and security of supply of electricity; and

[1] NEL, section 7.

(b) the reliability, safety and security of the national electricity system.

Further, the NEL specifies that in performing or exercising its regulatory functions or powers, the AER must ensure that the regulated DNSP to which the determination applies, and any affected registered participant are, in accordance with the NER: [2]

(i) informed of material issues under consideration by the AER; and

(ii) given a reasonable opportunity to make submissions in respect of that determination before it is made.

Section 7A of the NEL also specifies revenue and pricing principles that the AER must take into account in making a distribution determination in relation to direct control network services. These principles are:

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in–

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes –

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted–

(a) in any previous–

(i) as the case requires, distribution determination or transmission determination; or

(ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or

(b) in the Rules.

2 NEL, section 16.

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

1.1.2 National Electricity Rules

Chapter 6 of the NER sets out provisions that the AER must apply in exercising its regulatory functions and powers for electricity distribution networks. In particular, the AER must make a distribution determination for each Victorian DNSP that includes a:

- building block determination in respect of standard control services
- determination in respect of alternative control services
- determination relating to the negotiating framework for negotiated distribution services
- determination specifying the negotiated distribution service criteria (NDSC) for negotiated distribution services.

A distribution determination is predicated on constituent decisions to be made by the AER, specified in clause 6.12.1 of the NER.

Building block determination

Clause 6.3.2(a) of the NER requires that a building block determination specify for a regulatory control period the following matters:

(1) the Distribution Network Service Provider's annual revenue requirement for each regulatory year of the regulatory control period;

(2) appropriate methods for the indexation of the regulatory asset base;

(3) how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme are to apply to the Distribution Network Service Provider;

(4) the commencement and length of the regulatory control period;

(5) any other amounts, values or inputs on which the building block determination is based (differentiating between those contained in, or inferred from, the service provider's building block proposal and those based on the AER's own estimates or assumptions).

Determination in respect of alternative control services

Clause 6.12.1(12) of the NER requires the AER to make a decision on the control mechanism for alternative control services in accordance with the *Framework and approach paper* for the relevant DNSP. Clause 6.2.6 of the NER requires the control mechanism to have a basis as stated in the distribution determination, and specifies that it may (but need not) utilise elements of the building block determination for standard control services.

Negotiating framework determination

Clause 6.7.3 of the NER requires that:

> The determination specifying requirements relating to the negotiating framework forming part of a distribution determination for a Distribution Network Service Provider is to set out requirements that are to be complied with in respect of the preparation, replacement, application or operation of its negotiating framework.

Clause 6.7.5(a) of the NER requires that:

> A Distribution Network Service Provider must prepare a document (the negotiating framework) setting out the procedure to be followed during negotiations between that provider and any person (the Service Applicant or applicant) who wishes to receive a negotiated distribution service from the provider, as to the terms and conditions of access for the provision of the service.

Negotiated distribution service criteria

Clause 6.7.4 of chapter 6 of the NER requires that:

> (a) The determination by the AER specifying the Negotiated Distribution Service Criteria forming part of a distribution determination for a Distribution Network Service Provider is to set out the criteria that are to be applied:
>
> (1) by the provider in negotiating terms and conditions of access including:
>
> (i) the prices that are to be charged for the provision of negotiated distribution services by the provider for the relevant regulatory control period; or
>
> (ii) any access charges which are negotiated by the provider during that regulatory control period; and
>
> (2) by the AER in resolving an access dispute about terms and conditions of access including:
>
> (i) the price that is to be charged for the provision of a negotiated distribution service by the provider; or
>
> (ii) any access charges that are to be paid to or by the provider.

1.2 Derogations

Chapter 9 of the NER contains Victorian specific derogations.

Clause 9.8.7 specifies provisions regarding the transitional application of the former chapter 6 of the NER to Victorian distribution networks.

Clause 9.8.8 excludes the AER's power to aggregate distribution systems and parts of distribution systems in Victoria.

1.3 Transitional arrangements

Several transitional arrangements have been included in the NER for the AER’s first distribution determination for Victorian DNSPs.

Clause 11.17.2 requires the AER to adopt the same taxation values, asset classification and depreciation method used in the ESCV's 2006 determination when calculating the estimated cost of corporate income tax, with departures allowed in the event of changes in taxation laws or rulings by the Australian Taxation Office.

Clause 11.17.3 regards the assessment of building block proposals submitted in the absence of a statement of regulatory intent (SORI), which did not apply as the AER's SORI was published in early 2009.

Clause 11.17.4 required the AER to formulate Victorian specific cost allocation guidelines which were published on 26 June 2008.[3] As required under clause 11.17.5(a) of the NER, Victorian DNSPs submitted their proposed Cost Allocation Method by the time their building block proposals were submitted to the AER.

Clause 11.17.6 specifies that metering services dealt with under the Advanced Metering Infrastructure (AMI) Order in Council are not subject to regulation under a distribution determination published under chapter 6 of the NER. The AER published a separate budgets and charges determination in relation to AMI in October 2009.[4] The regulatory arrangements relating to the AMI rollout are set out in an August 2007 Order in Council made by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000. An amending Order in Council was made on 25 November 2008 (the ‘revised Order’).[5]

1.4 Review process

The AER has reviewed the Victorian DNSPs’ revised regulatory proposals and revised proposed negotiating frameworks as well as all submissions in accordance with the review process outlined in Part E of chapter 6 of the NER.[6] The AER has

3 AER, *Victorian electricity distribution network service providers - Cost allocation guidelines*, June 2008.

4 AER, *Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications*, October 2009.

5 The revised order is the Order in Council made on 28 August 2007 by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000, as amended on 25 November 2008, 22 January 2009 and 31 March 2009.

6 CitiPower and Powercor did not provide, and the AER did not review, revised negotiating frameworks because the AER's draft decision determined that the initial negotiating frameworks proposed by CitiPower and Powercor were compliant with the NER.

also applied the derogations and transitional arrangements set out above. This process involved:

Pre draft decision

- **Pre-consultation—**the AER consulted with the Victorian DNSPs regarding the development of the regulatory information notice (RIN), regulatory templates and guidelines.

- **Framework and approach—**the AER consulted with Victorian DNSPs and interested stakeholders regarding the development of the Framework and approach paper, with respect to the classification of services, control mechanism, and application of schemes. The Framework and approach paper was published in May 2009, as required under clause 6.8.1 of the NER.

- **Proposal—**the Victorian DNSPs submitted their regulatory proposals and proposed negotiating frameworks to the AER on 30 November 2009. The AER assessed the Victorian DNSPs' proposal against chapter 6 of the NER and the AER's guidelines.

- **Public consultation—**the AER published the Victorian DNSPs' regulatory proposals and the AER's proposed NDSC on 23 December 2009 and called for submissions from interested parties. The AER held a public forum in Melbourne on the Victorian DNSPs' regulatory proposals on 17 December 2009, where the Victorian DNSPs and interested parties gave presentations.

- **Submissions—**the AER received 20 submissions on the Victorian DNSPs' regulatory proposals or the AER's proposed NDSC.

- **Assessment by technical experts—**the AER engaged Nuttall Consulting (Nuttall) as a technical expert to advise it on a number of key aspects of the regulatory proposals.[7] The consultants provided independent advice to the AER on these matters, based on their reviews. The AER considered this advice in making its draft distribution determinations.

- **Assessment by demand forecasting experts—**the AER engaged ACIL Tasman as a technical expert to provide advice in relation to demand forecasts.[8]

- **Other specialist advice—**the AER also engaged Access Economics to provide a forecast of Victorian labour costs relevant to DNSPs.[9] Impaq Consulting was engaged to provide advice on alternative control services.[10]

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[7] Nuttall Consulting is a group of engineering and business consultants with a primary focus on specialised needs and operations in electric power, gas and other allied sectors.

[8] ACIL Tasman is an economic consulting firm providing analysis and advice on economics, policy and strategy to clients in Australia and internationally.

[9] Access Economics is an economic consulting firm that specialises in economic modelling, forecasting and policy analysis.

[10] Impaq Consulting has experience and expertise in the benchmarking of industry charge out rates, reviewing excluded service charges for metering, calculating excluded service costs and charges for DNSPs.

- The AER published its draft distribution determinations and draft decision for the Victorian DNSPs on 4 June 2010.

Post draft decision

- **Revised proposals**—to facilitate the preparation of revised regulatory proposals in response to its draft distribution determinations, the AER further consulted with the Victorian DNSPs regarding the development of a modified RIN, regulatory templates and guidelines which was issued in conjunction with its draft decision. The Victorian DNSPs submitted their revised regulatory proposals to the AER in July 2010.

- **Submissions—**the AER received 27 submissions on the Victorian DNSPs' revised regulatory proposals or the AER's proposed NDSC. The submissions are listed in appendix A of this final decision.

- **Assessment by technical experts—**following Nuttall's engagement during the draft decision stage, the AER reengaged Nuttall as a technical expert to advise it on a number of key aspects of the revised regulatory proposals. The consultants provided independent advice to the AER on these matters. The AER considered this advice in making its final distribution determinations.

- The AER also engaged in consultation with the Victorian technical and safety regulator—Energy Safe Victoria (ESV). The ESV provided the AER with advice in relation to the recommendations arising from the Victorian Bushfire Royal Commission (VBRC). The Victorian DNSPs sought to implement a number of the recommendations from the VBRC, proposing them as part of their capital expenditure program, or as operating expenditure step changes. The AER considered this advice in making its final distribution determinations.

- The AER released it final distribution determinations and decision on 29 October 2010.

Following the receipt of the Victorian DNSPs' revised regulatory proposals and submissions, the AER consulted further with interested parties on some specific areas of this process. The AER consulted further on those areas which it considered that interested parties may not have been afforded an opportunity to comment on new material arising from submissions or the Victorian DNSPs which the AER took into account in making its decision, and in those areas where the AER was considering a departure from its position in the draft decision. Areas where the AER undertook further consultation include the close out of the ESCV S factor and the cost of debt.

The AER's analysis and assessment of the Victorian DNSPs' revised regulatory proposals, submissions and consultants' advice is set out in this final decision. The AER has published all the inputs into its final distribution determinations on its website. The AER notes that all inputs are provided, save for those which are considered confidential or commercially sensitive.

1.5 Structure of this final decision

The AER's consideration of the Victorian DNSPs' revised regulatory proposals, proposed negotiating framework and the negotiated distribution service criteria to apply are set out as follows:

- chapters 2 to 4 address the classification of services, arrangements for negotiation and control mechanisms for standard control services
- chapters 5 to 12 relate to key elements of the building block calculation
- chapters 13 to 17 set out the relevant schemes and pass through arrangements
- chapter 18 sets out the annual building block revenue requirements for the next regulatory control period
- chapters 19 to 20 set out the control mechanism for alternative control services and the AER's review of alternative control services
- chapter 21 sets out the distribution determinations outcomes monitoring framework and compliance.

For convenience, the chapters of the final decision have been published as a separate document to the appendices. Both documents are available at www.aer.gov.au.

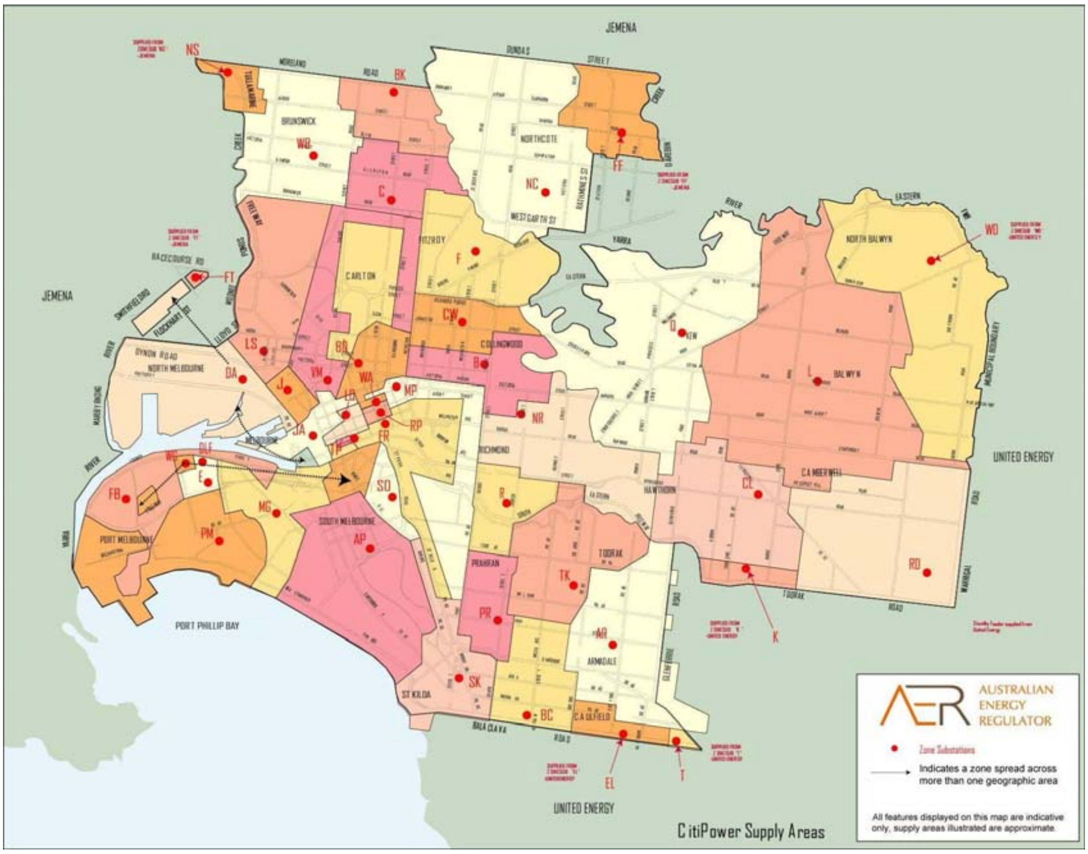
1.6 Overview of the Victorian electricity distribution network

The distribution networks of the five Victorian DNSPs are as follows:

CitiPower

CitiPower supplies over 300 000 customers (about 83 per cent residential) in a 157km² area of Melbourne's CBD, docklands and inner city. Its network includes 6 500 km of power line on 59 000 poles. About 17 per cent (by length) is classed as 'CBD', nearly 90 per cent of CBD lines are underground. It has common ownership and a common management structure with Powercor. Figure 1.1 is a map of CitiPower's distribution network.[11]

Figure 1.1 CitiPower supply area map



Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 106.

11 AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 66.

Powercor

Powercor supplies nearly 690 000 customers (85 per cent residential) in 146 000km² of Victoria. Its network includes part of Melbourne's Docklands precinct, and extends from Williamstown, north to the Murray, west to the South Australian border and south to the coast. Powercor uses 83 000 km of power line (65 per cent classified as 'rural') on 485 000 poles, and approximately 9.5 per cent of its length runs underground. Figure 1.2 is a map of Powercor's distribution network.[12]

Figure 1.2 Powercor supply area map

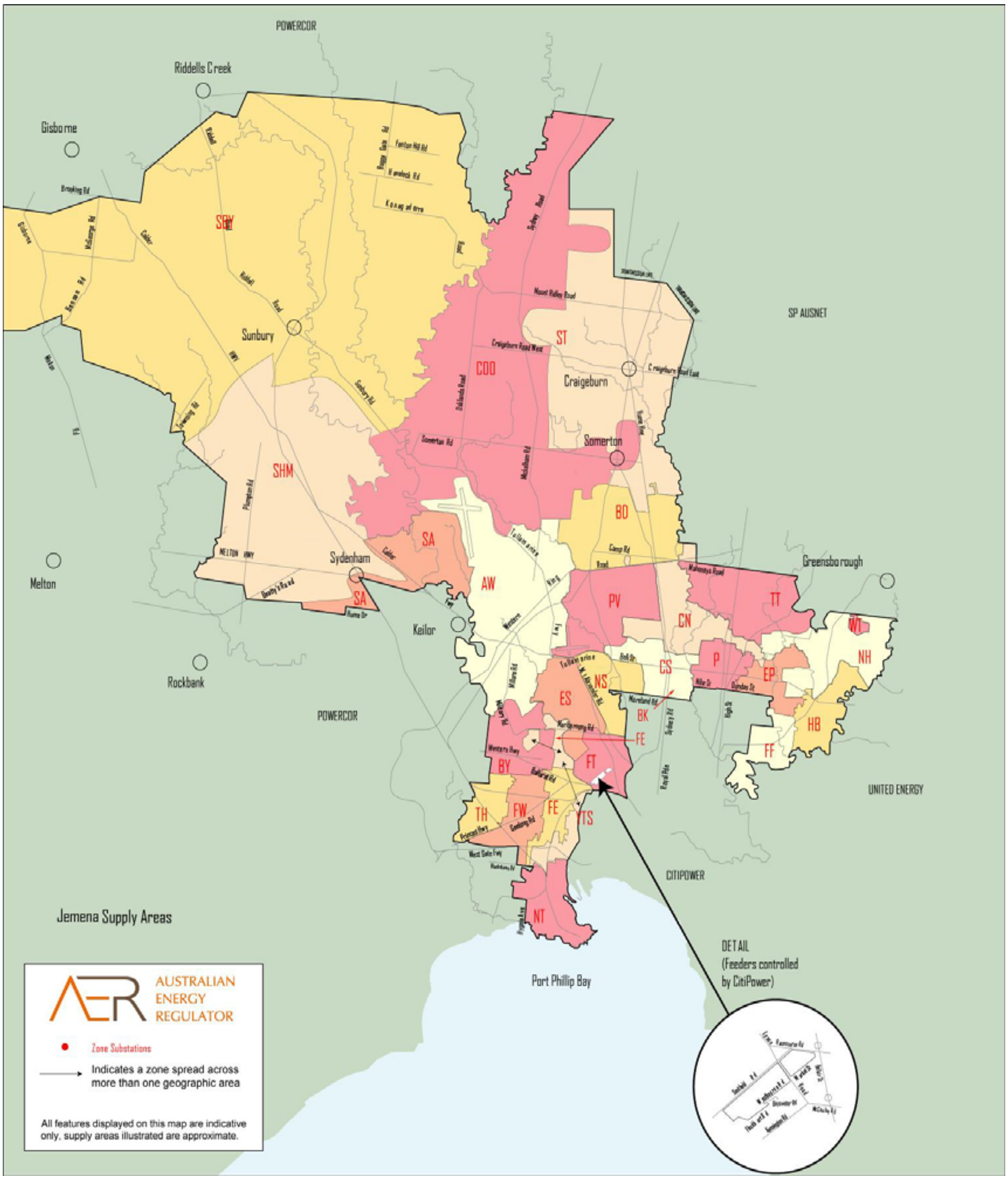
Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 117.

12 AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 66.

JEN

JEN supplies electricity to over 305 000 customers (89 per cent residential) in an 950 km² area. This area covers Melbourne's city and north-western suburbs, with Tullamarine International Airport at the approximate centre.[13] JEN supplies 12 per cent of Victorian customers and is the smallest of the five DNSPs in Victoria.[14] Figure 1.3 is a map of JEN's distribution area.

Figure 1.3 JEN supply area map



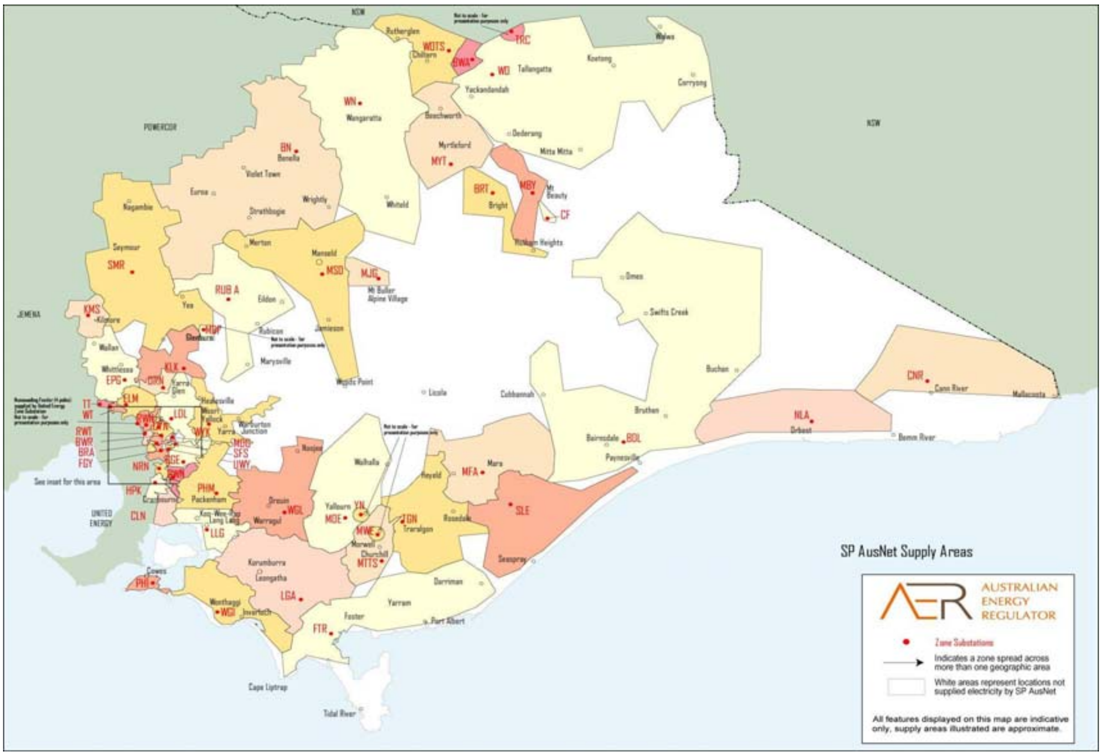
Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 113.

13 JEN, *Regulatory proposal 2011–15*, 30 November 2009, p. 14.
14 ibid, p. 15.

SP AusNet

SP AusNet's distribution network supplies 613 000 customers (88 per cent residential) in an 80 000km² area. This area extends from the fringe of the northern and eastern Melbourne metropolitan area, to the New South Wales border in the North, and to the Victorian coastline in the Southeast.[15] SP AusNet's distribution network assets include 47 66/22kV zone substations, 57 000 distribution substations, 384 000 power poles, 100 000 streetlights and 48 000 km of underground cable and overhead lines.[16] Its related companies also operate the electricity transmission network in Victoria. Figure 1.4 is a map of SP AusNet's distribution area.

Figure 1.4 SP AusNet supply area map



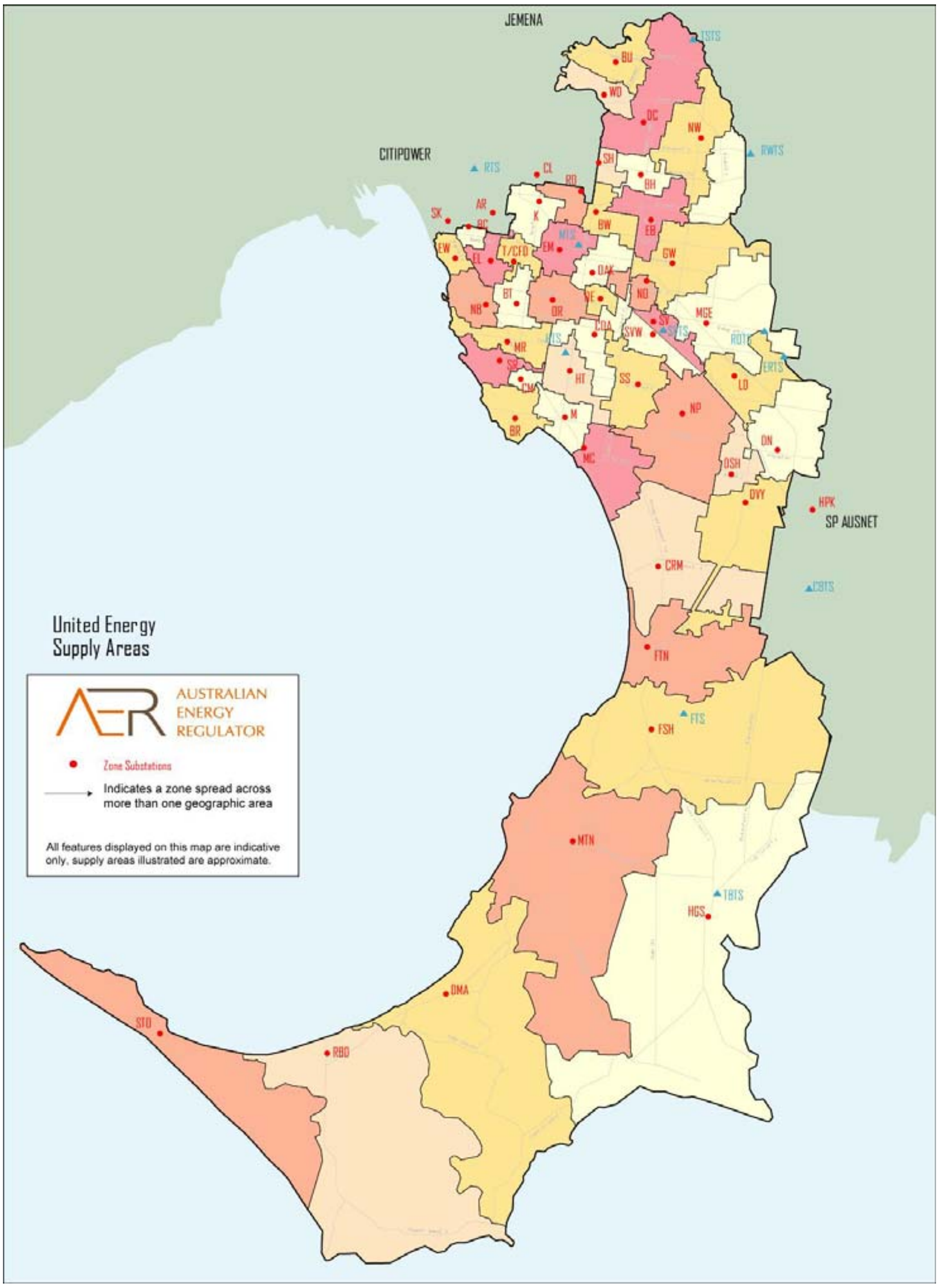
Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 125.

15 SP AusNet, *Electricity Distribution Price Review, Regulatory proposal*, November 2009, p. 21.
16 ibid.

United Energy

United Energy provides services to almost 630 000 end-use customers, located in an area of 1 472 km² in south-east Melbourne and the Mornington Peninsula.[17] Its distribution network comprises of 45 zone substations, approximately 211 000 poles, 11 500 distribution substations, 10 000km of overhead power lines and 2 300km of underground cables. Figure 1.5 is a map of United Energy's distribution area.

Figure 1.5 United Energy supply area map



Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 133.

[17] United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011—December 2015*, November 2009, p. 1.

2 Classification of services

2.1 AER draft decision

A distribution service is defined in the National Electricity Rules (NER) as '[a] service provided by means of, or in connection with, a distribution system.'

Distribution network is, in turn, defined as 'A distribution network, together with connection assets, which is connected to another transmission or distribution system.'[1] In accordance with clause 6.2.1 of the NER, the AER may classify distribution services as either:

- direct control services, or
- negotiated distribution services.

The note to clause 6.2.1 of the NER also makes it clear that the AER can decide against classifying a distribution service. Unclassified services are not subject to economic regulation by the AER.

Direct control services are the most heavily regulated distribution services, and are subject to one of the types of control mechanism in clause 6.2.5 of the NER, which are applied in this distribution determination. Negotiated distribution services are subject to more light handed regulation through the negotiated distribution services criteria (NDSC) and negotiating framework approved by the AER. Negotiated services are not included in the building block model. That is, the costs associated with these services are not included in opex or capex forecasts. Prices are also not set for negotiated services.

In classifying distribution services, the AER must have regard to several factors outlined in the NER. The AER, in its classification of distribution services, has had regard to all of these factors. In particular, clause 6.2.1(d) (1) and (2) of the NER provides that there should be no departure from the previous classification, and where there has been no previous classification, the classification should be consistent with the previous regulatory approach.

In Victoria, distribution services are currently classified in accordance with the Victorian Electricity Supply Industry Tariff Order 2005 (the Tariff Order) and the Essential Services Commission Victoria (ESCV) Electricity Industry Guideline 14 (Guideline 14). Under these instruments, distribution services are classified as either prescribed or excluded. Excluded services are further distinguished under Guideline 14 as either contestable excluded services or non-contestable excluded services.

The AER's draft decision regarding service classification responded to the Victorian distribution network service providers' (DNSPs') initial regulatory proposals. In those proposals, the Victorian DNSPs proposed several changes to the classification of

[1] NER, Chapter 10.

services set out in the AER's Framework and approach paper.[2] The AER's draft decision accepted the following changes to service classification set out in its Framework and approach paper:[3]

- connections requiring augmentation works—changed from negotiated services to standard control services (proposed by all five DNSPs)[4]
- standard/routine connections—changed from negotiated services to alternative control services (proposed by SP AusNet)[5]
- covering of low voltage mains for safety purposes—changed from alternative control service (fee based) to alternative control service (quoted) (proposed by SP AusNet)
- elective undergrounding—changed from alternative control service (fee based) to alternative control service (quoted) (proposed by SP AusNet)
- repair of damage to overhead cables caused by high load vehicles—changed from alternative control service (fee based) to alternative control service (quoted) (proposed by SP AusNet, CitiPower and Powercor)
- high load escorts (lifting overhead lines)—changed from alternative control service (fee based) to alternative control service (quoted) (proposed by SP AusNet, CitiPower and Powercor)
- manual meter investigations/special meter reading—these were not classified in the AER's Framework and approach paper. In the draft decision, they were classified as alternative control service (fee based) (proposed by CitiPower and Powercor)
- special meter manual reading—changed from alternative control service (metering) to alternative control service (fee based) (proposed by CitiPower and Powercor)
- location of underground cables—changed from alternative control service to standard control service (proposed by CitiPower and Powercor)
- energisation of new connections—changed from alternative control service to alternative control service (fee based) (proposed by CitiPower and Powercor)

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2 The AER's Framework and approach paper for the Victorian DNSPs was published in May 2009. This paper set out the AER's proposed classification of distribution services for the forthcoming regulatory period. In that paper, the AER's broad approach to classifying services was to classify prescribed services (as currently classified in the Victorian regulatory regime) as standard control services, excluded services (non contestable) as alternative control services, and excluded services (contestable) as negotiated services. Unregulated services were not classified under the NER. The AER's Framework and approach paper can be found at www.aer.gov.au.

3 The AER considered that there were good reasons for departing from the relevant classifications proposed in its Framework and approach paper in light of the DNSPs' regulatory proposal and the submissions received—see further clause 6.12.3(b) of the NER.

4 This change was also put forward by the Central Victorian Greenhouse Alliance (CVGA).

5 For customers below 100 amps, this is treated as an alternative control service (fee based) and for customers above 100 amps, an alternative control service (quoted service).

- photovoltaic (PV) installation—this service was not classified in the AER's Framework and approach paper. In the draft decision this service was classified as an alternative control service (fee based) (proposed by CitiPower and Powercor).[6]

The AER rejected the following changes to its framework and approach service classification proposed by the DNSPs:

- routine/standard connections—the AER rejected JEN's proposal to classify this as a standard control service and classified this as an alternative control service

- auditing design and construction, and specification and design enquiry—the AER rejected CitiPower's and Powercor's proposals to classify these services as standard control services and classified them as alternative control services

- temporary supply service—the AER rejected CitiPower's and Powercor's proposals to classify this as a standard control service and classified it as an alternative control service

- covering of low voltage mains—the AER rejected CitiPower's and Powercor's proposals to classify this service as a standard control service and classified it as an alternative control service

- elective undergrounding where an above ground service exists—the AER rejected CitiPower's and Powercor's proposals to classify this service as a standard control service and classified it as an alternative control service

- fault level compliance service—the AER rejected CitiPower's and Powercor's proposals to classify this service as a standard control service and classified it as an alternative control service

- reserve feeder—the AER rejected CitiPower's and Powercor's proposals to classify this service as a negotiated service and classified it as an alternative control service

- watchman lights (installation, and repair/maintenance)—the AER rejected CitiPower's and Powercor's proposals to classify these services as negotiated services, and instead did not classify these services

- re-test of type 5 and 6 meters—the AER rejected CitiPower's and Powercor's proposals to classify this service as unregulated and classified it as an alternative control service.[7]

The AER's draft decision regarding service classification was also set out at appendix B of the draft decision.

6 AER, *Victorian distribution determination 2011–15, Draft decision,* June 2010, pp. 36–38.
7 ibid., pp. 36–38.

2.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor both accepted the AER's draft determination on service classification.[8] However, CitiPower noted that it would not be providing the fault level compliance service (which was proposed in its original regulatory proposal as a standard control service).[9] Both CitiPower and Powercor clarified that the 'reserve feeder' service only relates to the operation and maintenance costs associated with the reserve feeder.[10]

JEN broadly accepted the AER's draft determination on service classification.[11] JEN noted that it did not agree with the AER's draft decision reasoning on the classification of routine connections as alternative control services, but accepted this classification in its revised proposal.[12] JEN also reiterated that supply abolishment should be classified as a quoted alternative control service (as opposed to a fee based service).[13] In proposing this, JEN stated that:

> JEN considers that complex supply abolishment of large supplies (underground and overhead), including substation abolishment, are best offered as a quoted service, because the scope of works and costs can vary significantly from one job to another. JEN submits that its proposal to include underground supply and substation abolishment as a quoted service is consistent with long-standing industry practice in Victoria. JEN believes the AER should consider this additional information before making a final decision on the appropriate treatment for supply abolishment services.[14]

SP AusNet accepted the AER's draft determination on service classification.[15]

United Energy also accepted the AER's draft determination on service classification.[16]

2.3 Submissions

The AER received two stakeholder submissions on service classification, from the Property Council of Australia (PCA) and from the Victorian Employers Chamber of Commerce and Industry (VECCI).

The PCA expressed concern with the current arrangements for connection of embedded generators in the Melbourne CBD.[17] The submission discussed the fault level compliance service, proposed by CitiPower.[18]

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8 CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 59; Powercor, *Revised Regulatory Proposal 2011 to 2015, 21 July 2010*, p. 55.

9 ibid., p. 59.

10 ibid.; Powercor, *Revised regulatory proposal*, p. 55.

11 JEN, *Revised Regulatory Proposal 2011–15*, 20 July 2010, p. 15.

12 ibid., p.16. JEN proposed this service as a standard control service in its initial regulatory proposal.

13 ibid., p. 340.

14 ibid., pp. 340–341.

15 SP AusNet, *Electricity Distribution Price Review, Revised Regulatory Proposal*, July 2010, pp. 19–21.

16 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, pp. 231–233.

17 Property Council of Australia (PCA), *Submission to the AER: CitiPower's original regulatory proposal 2011–2015 for the fault level compliance service fee*, 28 August 2010, p. 2.

18 This service was proposed by CitiPower as part of its original regulatory proposal (see p. 28). CitiPower proposed that this be treated as a standard control service, and proposed capex

Specifically, PCA stated:

> We support the fee being set at the minimum level with co generation and tri generation connection proceeding on the CitiPower network. At the level proposed, CitiPower's costs could amount to a cost increase or around 50 per cent for a small installation, making some installation prohibitively expensive… the Property Council would prefer that the fee was collected on an annual based, rather than one up front fee. [19]

PCA also expressed dissatisfaction with the current arrangements for connection of embedded generation in Victoria. It noted that currently, connections of this nature are timely and expensive, and create an inequitable process of 'first in, best dressed' (citing locations with limited fault headroom being treated differently, depending on specific locational characteristics).[20] PCA further submitted that Guideline 14 and ESCV Electricity Industry Guideline 15 (Guideline 15) did not adequately deal with these issues.[21]

VECCI, in its submission, stated that for advanced metering infrastructure (AMI) services, it was inconsistent for the AER to set budgets for the provision of these services, but not to set charges.[22] VECCI stated that this may be based on the expectation that AMI services are potentially contestable and hence 'light handed' regulation is appropriate.[23] VECCI raised concerns with this approach and stated that the AER should reconsider the status of AMI-related services from a regulatory perspective.[24]

In subsequent consultation with the AER, SP AusNet proposed that the service 'after hours truck by appointment' be treated as a quoted service, rather than a fee based service.[25]

2.4 Issues and AER considerations

The AER notes that all the Victorian DNSPs generally accepted the AER's draft determination on service classification.

2.4.1 Supply abolishment

The AER concurs with JEN's revised proposal regarding the treatment of supply abolishment services. This service is classified as an alternative control service in this final decision but is treated as a quoted service rather than as a fee based service. This is to reflect the variability in the costs of providing this service, as noted by JEN in its revised regulatory proposal.[26]

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associated with the provision of this service. The AER's draft decision rejected this as a standard control service, and instead classified this as an alternative control service.

19 PCA, *Submission to the AER*, p. 4.

20 ibid., p. 3.

21 ibid.

22 VECCI, *Submission to the AER draft decision on distribution network tariffs for 2011–15*, 26 August 2010, p. 11.

23 ibid.

24 ibid.

25 SP AusNet, *response to information requested 17 August 2010*, 27 August 2010.

26 JEN, *Revised regulatory proposal*, pp. 340–34.

2.4.2 After hours truck by appointment service

The AER has considered SP AusNet's after hours truck by appointment service. The AER notes that the costs relating to this service are variable according to a number of different factors. Therefore, the AER will treat it as a quoted service for the 2011–15 regulatory control period.

2.4.3 Fault level compliance service

The AER notes the concerns raised by PCA in its submission including its preference for a fault level compliance service fee to be charged annually.

However, CitiPower has stated in its revised regulatory proposal that it will not provide this service during the 2011–15 regulatory control period. Whilst the AER is permitted under the NER to classify this service, it does not have power to compel its provision. Therefore, whilst the AER retains its draft decision position to classify this service as an alternative control service, it cannot compel CitiPower to provide this service. The AER notes that this service has not been provided by CitiPower in the current regulatory control period.

PCA’s submission comments on current regulatory arrangements for customers who wish to connect embedded generators to the distribution network. These arrangements are administered by the AER under Guideline 14 and Guideline 15. However the AER notes that it does not have power to change these instruments which have been established by the ESCV. Issues relating to these instruments can be directed to the ESCV.

2.4.4 AMI services

VECCI's submission noted the potential contestability of AMI services, and the subsequent 'light-handed' regulation of AMI services. The AER notes VECCI's statement that 'in the Draft Decision, these services are deemed to be ‘alternate control services’ or otherwise excluded from direct control'.[27]

The regulatory arrangements relating to the AMI rollout are set out in an August 2007 Order in Council made by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000. An amending Order in Council was made on 25 November 2008 (the revised Order). According to the revised Order, metering provision services and metering data provision services for type 1 to 4 metering installations, metering services provided to customers with annual consumption greater than 160 MWh that have either type 5 manually read interval meters or type 6 manually read accumulation meters are to be considered 'excluded services'. The AER is continuing this approach to classification in this draft determination.

However, these services, despite their title are not entirely 'excluded' from regulation. As VECCI has noted, the AER undertakes an AMI budget approval process. The prices of these services are subject to regulation under ESCV Guideline 14. Guideline 14 provides that charges for services must be fair and reasonable. Where a customer considers that the charge for the service is not fair and reasonable, the customer can seek recourse under the relevant provisions of Guideline 14 from the AER. Moreover,

[27] VECCI, *Submission to the AER*, p. 11.

whilst it is the DNSP that proposes these charges, the charges are ultimately approved by the AER under Guideline 14.

To consider that these services are not 'subject to direct control', as proposed by VECCI, is not correct. Excluded services under the Victorian regulatory regime (and regulated by Guideline 14) are analogous to alternative control services regulated under the NER. Alternative control services are a subset of direct control services.

2.4.5 Reserve feeder service

In their initial regulatory proposals, CitiPower and Powercor both submitted that reserve feeder services should be classified as negotiated services under the NER.[28] In its draft decision, the AER rejected this treatment, and classified this service as an alternative control service. Additionally, the AER stated that this service would be treated as a fee based service for the 2011–15 regulatory control period.[29] CitiPower and Powercor accepted this position in their revised proposals (noting that associated charges for reserve feeder services related only to operation and maintenance costs).[30]

In its revised proposal, JEN provided a cost breakdown of it's operating and maintenance charges for reserve feeder services, as requested by the AER.[31] The operation and maintenance cost of providing this service was \$3.96 per kW.[32] However, in their initial regulatory proposal, JEN proposed a charge of \$17.57 per kW. In subsequent correspondence between AER staff and JEN staff, JEN indicated that additional costs are incurred in the provision of this service (which is the reason for the difference between the operating and maintenance costs and the proposed charge), namely for:

- future asset replacement costs, to be incurred around 20–30 years after the initial assets are installed, depending on the regulatory arrangements at that time

- the financing of deep connection costs, the assets for which are not paid for upfront by the customer (unlike CitiPower and Powercor), although the assets are rolled into JEN’s regulatory asset base (RAB) at the end of the relevant regulatory period.[33]

On the latter issue, JEN acknowledged the associated deep connection costs could be recovered under Guideline 14.[34] The AER considers this to be the correct treatment of cost recovery for deep connection under the Victorian regulatory framework for network connection, as customers would pay the deep connection costs incurred by JEN consistent with the method for calculating those costs under Guideline 14, rather than an estimate of those costs by JEN which is currently factored into JEN's price.

On service classification, JEN noted:

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28 CitiPower, *Regulatory proposal 2011–15*, November 2009, p. 22; Powercor, *Regulatory proposal 2011–15*, November 2009, p. 22.
29 AER, *Draft decision*, p. 33.
30 CitiPower, *Revised regulatory proposal* p. 59; Powercor, *Revised regulatory proposal*, p. 55.
31 JEN, *Revised regulatory proposal*, appendix 20.7.
32 ibid.
33 JEN, *response to information requested 8 September 2010*, 15 September 2010.
34 JEN, *response to information requested 8 September 2010*, 15 September 2010, attachment 2, page 2.

> JEN also notes that, as explained in section 19.23.2 of JEN's original regulatory proposa1, historically, the Essential Services Commission of Victoria (ESC) did not review or approve charges for JEN's reserve feeder service, leaving it to JEN to negotiate the price with the customer on a fair and reasonable basis. This approach is akin, within the National Electricity Rules (NER) framework, to a classification as a negotiated service. Customers that consider the option of enhancing their supply by obtaining a reserve feeder service also have the option of installing their own back up generator instead. One option would therefore be for the AER to maintain the historic approach by classifying reserve feeder as a negotiated service.
>
> Historically, JEN has negotiated with customers in good faith to establish fair and reasonable contracts that provide both JEN and the customer with certainty…There is nothing to suggest that the past classification of reserve feeder services as negotiated services was inappropriate. In light of this, and together with the very small number of these services that JEN provides, there is no proper basis for the AER to reclassify these services. Clause 6.2.1(d) of the NER provides that for services that have previously been subject to regulation, there should be no departure from the previous classification (or if there has been no classification, the classification should be consistent with the previously applicable regulatory approach) unless a different classification is "clearly appropriate". There is no material or evidence before the AER that suggests the previous classification of these services was inappropriate, or that a different classification would be "clearly appropriate".[35]

On this, the AER accepts JEN's assertions on the current ESCV classification of the reserve feeder as being an excluded service. Further, whilst JEN is of the view that its current supply arrangements are analogous to a negotiated service under the NER on the basis that it negotiates with customers in good faith to establish fair and reasonable charges, the AER considers that there are good reasons to retain its draft decision classification of alternative control services.[36]

In reaching this conclusion, the AER has had regard to the form of regulation factors set out in the NEL.[37] Specifically, the AER considers that there is limited information available to customers which may empower them to negotiate charges for this service (section 2F(g) of the NEL). The AER considers that the difference between the operating and maintenance costs outlined by JEN and the proposed price for this service (which is about 25% of the full starting price proposed by JEN) demonstrates this. If information was available to customers, they would be able to negotiate a price that is more cost reflective (that is, have the capital contribution determined under Guideline 14, and pay the operating and maintenance charge as the fixed price component of this service).

The AER further notes that, if a customer has already had a reserve feeder service installed, the additional cost and potential site and regulatory constraints on installing a back up generator (should the customer consider JEN's reserve feeder price too high) are prospective barriers to switching from a reserve feeder to a generator. On

35 ibid., p. 1.

36 Clause 6.2.1(c) and (d) of the NER indicate that the AER should classify services with regard to the form of regulation previously applicable to that service, unless a different classification is clearly more appropriate.

37 See s.2F of the NEL. The AER must consider the form of regulation factors under cl. 6.2.1 (c) (1) of the NER in determining whether or not to classify distribution services as negotiated services or direct control services.

this basis, the AER considers that these services are not direct substitutes for one another.

The AER considers that, because JEN can discern the cost up front (as evidenced by the charge proposed by JEN) and has a set charge for reserve feeder services, it is apparent that there is no 'negotiated' price for this service. The AER further notes that, in a list of customers who receive this service (as provided by JEN), all customers save for one are charged the same price. This is further evidence that a fixed charge can be set and maintained. A negotiated service, as the name suggests indicates that all terms and conditions of that service, including price, can be negotiated on a case by case basis.

Therefore, having regard to the form of regulation factors at section 2F (d) and 2F (e) of the NEL, the AER considers that JEN has strong market power in the provision of its reserve feeders services, which is not mitigated by the presence of direct substitutes for these services.

The AER notes that JEN has advised that it cannot, in advance, calculate the historical deep connection financing costs and future asset replacement costs. JEN's proposed approach involves an arbitrary amount. Also, JEN has not been able to identify any unfunded costs from existing reserve feeder customers.[38] In contrast, calculating a deep connection cost and capital contribution charge in accordance with the methodology in Guideline 14 represents a more cost reflective charge to be incurred by customers. The AER considers that this is preferable to a price that merely contains forecasts or indications of cost.

For the reasons set out above, the AER maintains its draft decision, that is, to classify the reserve feeder service as an alternative control service

2.5 AER conclusion

The AER will apply the service classifications as set out in its draft decision. The only amendments to the draft decision is the treatment of supply abolishment services and after hours truck by appointment services, which are treated as 'quoted' alternative control service in this final decision. This is discussed further in chapter 20, which discusses pricing for alternative control services.

The AER will apply the service classifications as set out at appendix B of the final distribution determination for the forthcoming 2011–15 regulatory control period.

The AER's final decision regarding service classification is also set out at appendix B of this final decision.

[38] JEN, *Response to information requested* 15 September 2010, 30 September 2010

3 Arrangements for negotiation

3.1 AER draft decision

A distribution determination imposes price controls and revenue controls, which are recovered through the distribution network service provider (DNSP) provisions for direct control services.[1] However, services which are classified by the AER as negotiated distribution services do not have their terms and conditions, or their prices, set through a distribution determination. Rather, these services are subject to negotiation, arbitration and dispute resolution under the relevant provisions of the National Electricity Rules (NER).

This is facilitated through a negotiating framework (proposed by the DNSPs, approved by the AER and adhered to throughout the negotiating process) and negotiating distribution service criteria (NDSC), which are determined by the AER.

NDSC

The NDSC is a set of criteria that a DNSP must apply in negotiating the terms and conditions for its negotiated distribution services. The AER also applies the NDSC in resolving disputes over terms and conditions where they arise between the DNSP and the service applicant.

The NDSC sets out the criteria that are to be applied by a DNSP in negotiating terms and conditions of access including:

- the prices that are to be charged for the provision of negotiated distribution services by the provider for the relevant regulatory control period; or

- any access charges which are negotiated by the provider during the regulatory control period.[2]

The NDSC will also be used by the AER in resolving any access dispute about the terms and conditions of access, including:

- the price that is to be charged for the provision of the negotiated distribution service by the provider; or

- any access charges that are to be paid to or by the provider.[3]

The NDSC to apply to the Victorian DNSPs for the forthcoming regulatory control period was set out at appendix D of the AER's draft decision. The NDSC was released for stakeholder consultation with the Victorian DNSPs' original regulatory proposals in December 2009. No submissions were received on the proposed NDSC for the Victorian DNSPs.

[1] National Electricity Rules (NER), cl. 6.2.1 (a)
[2] NER, cl. 6.7.4 (a) (1).
[3] NER, cl. 6.7.4 (a) (2).

Negotiating framework

In reviewing the negotiating framework, the AER must ensure that it is satisfied that the negotiating framework adequately complies with clause 6.7.5 of the NER. This clause sets out that the negotiating framework must comply and be consistent with the applicable requirements of the relevant distribution determination, and the minimum requirements provided under clause 6.7.5(c), which require:

- the service applicant and service provider to negotiate in good faith the terms and conditions of access, and to provide each other with all such commercial information as reasonably required to engage in effective negotiation with the provider:
  - to identify and inform the service applicant of the reasonable costs (and increase or decrease in costs) of providing the service; and to demonstrate that charges for the service are cost reflective
  - to have appropriate arrangements for assessment and review of the charges and the basis on which they are made.
- the arrangements for provision of the service be commenced and finalised within specified periods (and a requirement that each party to the negotiations must make reasonable endeavours to adhere to these)
- a process for dispute resolution under the NER and National Electricity Law (NEL)
- the arrangements for payment of the DNSP's reasonable direct expenses incurred in processing the application to provide the negotiated distribution service
- the DNSP to determine the potential impact on other network users of the provision of the negotiated distribution service; and that the DNSP must notify and consult with any affected network users (ensuring that the provision of service does not result in non compliance with obligations to users under the NER)
- the DNSP to publish the results of negotiations on its website.[4]

A DNSP and a service applicant negotiating for the provision of a negotiated distribution service must comply with the requirements of the negotiating framework in accordance with its terms.[5]

In its draft determination, the AER can refuse to approve a DNSP's proposed negotiating framework.[6] If this occurs, the AER’s determination on a DNSP’s negotiating framework must set out any requirements or amendments that are required in respect of the preparation, replacement, application or operation of the DNSP’s negotiating framework.

[4] NER, cl. 6.7.5 (c).
[5] NER, cl. 6.7.5 (e).
[6] NER, cl. 6.7.3.

As part of their regulatory proposals, CitiPower, Powercor, Jemena Electricity Networks (JEN), SP AusNet and United Energy each provided a proposed negotiating framework. The AER's draft decision assessed those proposed negotiating frameworks in accordance with cl. 6.12.1 (15) of the NER. The AER approved CitiPower's and Powercor's negotiating frameworks in its draft decision, as it deemed they were compliant with the requirements of cl. 6.7.5 of the NER. The AER did not approve the negotiating frameworks proposed by JEN, SP AusNet and United Energy. The required amendments to render these negotiating frameworks compliant with the NER were set out at appendix C of the draft decision.

3.2 Issues and AER considerations

3.2.1.1 Victorian DNSP revised regulatory proposals

JEN, SP AusNet and United Energy each submitted revised negotiating frameworks which incorporated the amendments required by the AER's draft decision.[7] CitiPower and Powercor were not required to make any changes to their negotiating frameworks.[8] CitiPower and Powercor therefore did not submit a revised negotiating framework.[9]

3.2.1.2 Issues and AER considerations

The AER approves JEN's, SP AusNet's and United Energy's revised negotiating frameworks and CitiPower's and Powercor's negotiating frameworks for the 2011–15 regulatory control period as it considers that they are compliant with clause 6.7.5 (a) and 6.7.5 (c). These are set out at appendix C of this final decision.

3.3 AER conclusion

3.3.1.1 NDSC

As set out when the NDSC were first released for consultation, and in the AER's draft decision, the AER considers that the NDSC are consistent and give effect to the negotiated distribution service principles in clause 6.7.1 and 6.7.4 of the NER. The NDSC applying to CitiPower, Powercor, JEN, SP AusNet and United Energy for the forthcoming regulatory control period are unchanged from the draft decision and are set out in appendix D of this final decision. In accordance with clause 6.12.1 (6) of the NER, these NDSC will apply for the forthcoming regulatory control period.

[7] Jemena Electricity Networks (JEN), *Revised Regulatory Proposal 2011–15*, 20 July 2010, pp. 17–18 and Appendix C.3; SP AusNet, *Electricity Distribution Price Review, Revised Regulatory Proposal*, July 2010, p. 392 and Appendix Q; United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011 – December 2015*, July 2010, pp. 337–338.

[8] AER, *Victorian distribution determination 2011–15, Draft decision,* June 2010, p. 46.

[9] CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 50; Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 48.

3.3.1.2 Negotiating frameworks

In accordance with clause 6.12.3(g) and 6.7.3 of the NER, the AER approves the revised negotiating frameworks provided by JEN, SP AusNet and United Energy. These comply with the requirements of Part D of the NER. The approved negotiating frameworks for each of the Victorian DNSPs are set out at appendix C of this final decision. The AER approves these negotiating frameworks in accordance with clause 6.12.1 (15) of the NER.

4 Control mechanism for standard control services

The AER published a Framework and approach paper setting out the control mechanisms it proposes to apply to direct control services provided by the Victorian DNSPs during the forthcoming regulatory control period.[1] For the Victorian DNSPs' standard control services this control mechanism is a weighted average price cap (WAPC).

This chapter discusses how the WAPC control mechanism for standard control services will be applied and sets out how the AER will determine compliance with the control mechanism during the next regulatory control period.[2]

This chapter also discusses the mechanism through which the Victorian DNSPs will recover charges described in clauses 6.18.7 and 6.18.7A of the NER—including adjustments for under or over recovery of those charges—in the forthcoming regulatory control period.[3]

In addition, this chapter discusses the procedures for assigning or reassigning customers to tariff classes.[4] These procedures apply to all direct control services.

4.1 AER draft decision

The AER, in its draft decision, set out the WAPC formula that applies to the Victorian DNSPs in the forthcoming regulatory control period.[5]

The AER did not accept CitiPower's, Powercor's, Jemena Electricity Network's (JEN's) and United Energy's proposal that a factor be included in the WAPC formula to account for actual 2010 performance under the S factor scheme.[6]

The AER agreed with SP AusNet's and United Energy's interpretation of the NER[7], that is, that the NER does not allow DNSPs to recover at the pricing proposal stage connection charges levied upon them by TNSPs. The AER also considered that the NER[8] does not allow DNSPs to recover at the pricing proposal stage inter-DNSP charges and avoided TUOS charges.[9] Further, the AER did not accept CitiPower's, Powercor's and JEN's proposal that costs incurred under the Victorian PFIT scheme also be recovered through the TUOS recovery mechanism in the NER.[10]

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1 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009.
2 Clause 6.12.1(11) and 6.12.1(13), respectively.
3 Clause 6.12.1(19) and 6.12.1(20) respectively.
4 Clause 6.12.1(17).
5 AER, *Victorian distribution determination 2011–2015*, Draft decision, June 2010, p. 69.
6 ibid., pp. 58–59.
7 Clause 6.18.7.
8 Clause 6.18.7.
9 AER, *Draft decision*, pp. 64–66.
10 Clause 6.18.7. See also AER, *Draft decision*, pp. 62–64.

The AER's procedure for assigning and reassigning customers to tariff classes for the Victorian DNSPs was set out in appendix G of the draft decision.[11]

4.2 Victorian DNSP revised regulatory proposals

4.2.1 Weighted average price cap formula

4.2.1.1 Licence fee (L_t) factor

CitiPower and Powercor stated that setting the value of L'_{t-1} to zero in the first two years of the forthcoming regulatory control period as set out in appendix E.2 of the draft decision will result in an incorrect adjustment factor for L. CitiPower and Powercor considered that given that the L factor is already in place, there is no need for this requirement in the final decision. Accordingly, L'_{t-1} should be defined as the 'the value of L'_t determined in the calendar year *t–1*'.[12]

JEN stated that 'the clauses setting L to zero in 2011 and 2012 [in the draft decision] should be removed' to enable the recovery of 2009 and 2010 licence fees.[13]

SP AusNet accepted the Licence Fee factor proposed by the AER.[14]

4.2.1.2 S factor true up

CitiPower and Powercor did not accept the AER's draft decision regarding the S factor true up in the 2016-20 distribution determination. CitiPower and Powercor proposed including a new term in the WAPC and side constraint formulae to address the S factor true up (T_t).[15]

CitiPower and Powercor commented that the interpretation of clause 6.12.3(c) of the NER in the draft decision—that it constrains the AER's ability to amend the WAPC formula—is contrary to the AER's QLD and SA distribution determinations. In those distribution determinations the AER interpreted clause 6.12.3(c) of the NER as preventing the AER from changing the form of control (for example, from a WAPC to a revenue cap) but not preventing amendment of the WAPC formula. CitiPower and Powercor noted that the AER also applied a similar interpretation of clause 6.12.3(c) of the NER in the draft decision for Victorian DNSPs by adding a pass through term to the WAPC formula and amending the definition of CPI and the licence fee factor. CitiPower and Powercor considered that the AER's interpretation of clause 6.12.3(c) of the NER in the SA draft determination is correct and does not prevent the AER from adding new terms such as T_t in the WAPC formula.[16]

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11 AER, *Draft decision*, Appendices, pp. 20–22.

12 CitiPower, *Revised regulatory proposal: 2011 to 2015*, 21 July 2010, pp. 77–78; Powercor, *Revised regulatory proposal: 2011 to 2015*, 21 July 2010, p. 72.

13 JEN, *Revised regulatory proposal*, 20 July 2010, p. 22.

14 SP AusNet, *Electricity distribution price review 2011–2015, Revised regulatory proposal*, July 2010, p. 365.

15 CitiPower, *Revised regulatory proposal*, pp. 60–61 and 74; Powercor, *Revised regulatory proposal*, pp. 56–57 and 68.

16 CitiPower, *Revised regulatory proposal*, pp. 67–69; Powercor, *Revised regulatory proposal*, pp. 63–64.

CitiPower and Powercor did not agree with the AER's proposed method for calculating the S factor true up amount and proposed an alternate methodology.[17]

JEN expressed concern that the AER cannot bind itself or any future regulator to allow for the S factor true-up in the 2016-20 distribution determination. JEN also commented that the AER’s assertion that the NER limits changes to the WAPC formula is at odds with the addition of a pass through parameter. JEN proposed to recover the true up in 2013, and otherwise considered that the 2010 true up should be recovered through the STPIS.[18]

4.2.1.3 S factor specification

JEN stated that the draft decision does not specify how the S factor in the WAPC will be calculated and requested that the AER publish its proposed S factor parameter specification for consultation.[19]

4.2.1.4 WAPC formula specification

CitiPower, Powercor, JEN and SP AusNet proposed a new specification for the left hand side of the WAPC formula. CitiPower, Powercor and JEN considered that this is necessary to comply with appendix E of the draft decision particularly where there are changes to tariff structures such as when tariff reassignments occur.[20] The left hand side of the WAPC formula proposed by CitiPower, Powercor, JEN and SP AusNet is:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_{t-2}^{ij}}{\sum_{g=1}^{n}\sum_{h=1}^{m}\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ghij} q_{t-2}^{ghij}}$$

where

> tariff *i* and component *j* represent the proposed pricing segment in year *t*; tariff *g* and component *h* represent the source pricing segment from year *t–1* that has been mapped to tariff *i* and component *j*. There are *n* tariffs and up to *m* tariff components in total;
>
> p_t^{ij} is the proposed distribution price for component *j* of distribution tariff *i* in regulatory year *t*;
>
> q_{t-2}^{ij} is the audited from regulatory year *t–2* that is mapped to component *j* of distribution tariff *i* in regulatory year *t*. (Note that this quantity may have actually been delivered to other tariffs than *i* and components *j* in year *t–2*);
>
> p_{t-1}^{ghij} is the distribution price that was charged in regulatory year *t–1* for the subset of component *j* of distribution tariff *i* that was mapped from the source component

[17] CitiPower, *Revised regulatory proposal*, p. 74; Powercor, *Revised regulatory proposal*, pp. 68–69.
[18] JEN, *Revised regulatory proposal*, p. 23.
[19] ibid., p. 22.
[20] CitiPower, *Revised regulatory proposal*, p. 75; Powercor, *Revised regulatory proposal*, pp. 70; JEN, *Revised regulatory proposal*, p. 23.

h of source tariff *g*. (Note that $p_{t-1}^{ghij} = p_{t-1}^{gh}$ for all destination tariffs i and components j. If there is no tariff reassignment then *g=I* and *h=j*, and $p_{t-1}^{ghij} = p_{t-1}^{ij}$); and

q_{t-2}^{ghij} is the audited quantity from regulatory year *t–2* for the subset of component *j* of distribution tariff *i* that was mapped from source component *h* of source tariff *g* (If there is no tariff reassignment then *g=i* and *h=j*).[21]

JEN provided a worked example demonstrating how the amended WAPC formula would operate when a tariff reassignment occurs.[22]

United Energy submitted that the WAPC formula should be amended to include a double summation for prices rather than a single sum on quantities as a double summation will accommodate the introduction of new tariffs and allow assignment to those new tariffs within the NER.[23]

4.2.1.5 Pass through parameter

CitiPower and Powercor considered that the definition in the draft decision for the pass through parameter in the WAPC is unworkable, particularly if there is no pass through amount in the previous year. CitiPower and Powercor recommended that the pass through parameter be determined as a portion of the annual revenue entitlement with a mechanism added to perform a true up between actual and estimated amounts. CitiPower and Powercor recommended replacing the pass through parameter in the draft decision's WAPC and side constraint formulae with '$\times(1+P_t)$'.[24]

JEN and SP AusNet proposed the removal of the '$\pm(passthrough_t)$' parameter from the WAPC formula and that this be replaced by the maximum pass through revenue (*MPR*) mechanism. The *MPR* allows the recovery of all pass through costs, including those formerly recovered under the ESCV's maximum transmission revenue (MTR) mechanism. JEN and SP AusNet propose that pass through costs are recovered separately from DUOS tariffs under the *MPR* such that NUOS tariffs comprise of DUOS tariffs plus pass through tariffs derived from the *MPR*.[25]

JEN recommended that if the AER retains the pass through parameter, the '$\pm(passthrough_t)$' term be replaced with a '$\times(1+passthrough_t)$' term to ensure all elements of the WAPC formula are treated consistently.[26] United Energy also

21 These definitions are taken from CitiPower, *Revised regulatory proposal*, p. 76. Similar definitions can be found in: Powercor, *Revised regulatory proposal*, pp. 70–71; JEN, *Revised regulatory proposal*, p. 24; SP AusNet, *Revised regulatory proposal*, pp. 376–377.

22 JEN, *Revised regulatory proposal*, Appendix 4.2, 20 July 2010.

23 United Energy, *Revised regulatory proposal for distribution prices and services January 2011–December 2015*, July 2010, p. 282.

24 CitiPower, *Revised regulatory proposal*, p. 75, appendix 3.1, attachment 18; Powercor, *Revised regulatory proposal*, pp. 69–70, appendix 3.1, attachment 18.

25 JEN, *Revised regulatory proposal*, p. 25; SP AusNet, *Revised regulatory proposal*, pp. 375.

26 JEN, *Revised regulatory proposal*, p. 25.

proposed that the '$\times\left(1+passthrough_t\right)$' term should be included in the WAPC formula in place of the '$\pm\left(passthrough_t\right)$' term.[27]

4.2.1.6 Side constraints

CitiPower, Powercor and JEN proposed amending the side constraints formula to enable compliance with appendix E of the draft decision where there are changes to tariff structures.[28] SP AusNet and United Energy commented that the side constraint formula in section 4.6.2 of the draft decision appears to apply at the tariff component level whereas the stated intention in the draft decision (and as required by clause 6.18.6(a) of the NER) is to apply the side constraint to tariff classes.[29]

CitiPower, Powercor, JEN and SP AusNet proposed the following expression for the left hand side of the side constraints formula:

$$\frac{\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_t^{cij} q_{t-2}^{cij}}{\sum_{g=1}^{n}\sum_{h=1}^{m}\sum_{i=1}^{n^c}\sum_{j=1}^{m^c} p_{t-1}^{ghcij} q_{t-2}^{ghcij}}$$

where:

> *regulatory year t* is the regulatory year in respect of which the calculation is being made;
>
> *regulatory year t–1* is the regulatory year immediately preceding regulatory year *t*;
>
> *regulatory year t–2* is the regulatory year immediately preceding regulatory year *t–1*;

for each tariff class *c*:

> tariff *i* and component *j* represent the proposed pricing segment in year *t*; tariff *g* and component *h* represent the source pricing segment from yeat *t–1* that has been mapped to tariff *i* and component *j*. Each tariff class *c* has n^c tariffs, with up to m^c components. Not that tariff *g* and component *h* are not necessarily of the same tariff class as tariff *i* and component *j*, if tariff reassignment between classes occurs; Note: source tariff *g* and component *h* are summed over all tariff and components from all classes;
>
> p_t^{cij} is the proposed distribution price for component *j* of distribution tariff *i* in regulatory year *t*;

27 United Energy, *Revised regulatory proposal*, pp. 281–282.

28 CitiPower, *Revised regulatory proposal*, p. 76–77; Powercor, *Revised regulatory proposal*, pp. 71–72; JEN, *Revised regulatory proposal*, p. 25.

29 SP AusNet, *Revised regulatory proposal*, pp. 374 and 377; United Energy, *Revised regulatory proposal*, pp. 277–278.

q_{t-2}^{cij} is the audited from regulatory year *t–2* that is mapped to component *j* of distribution tariff *i* in regulatory year *t*. (Note that this quantity may have actually been delivered to other tariffs than *i* and components than *j* in year *t–2*;

p_{t-1}^{ghcij} is the distribution price that was charged in regulatory year *t–1* for the subset of component *j* of distribution tariff *i* that was mapped from the source component *h* of source tariff *g*. (Note that $p_{t-1}^{ghcij} = p_{t-1}^{gh}$ for all destination tariffs I and components j. If there is no tariff reassignment then *g*=*i*, *h*=*j*, and $p_{t-1}^{ghcij} = p_{t-1}^{cij}$. Note also that source tariff *g* and source component *h* are not necessarily of class *c*.); and

q_{t-2}^{ghcij} is the audited quantity from regulatory year *t–2* for the subset of component *j* of distribution tariff *i* that was mapped from source component *h* of source tariff *g*. (If there is no tariff reassignment then *g*=*i* and *h*=*j*). Note that source tariff *g* and source component *h* are not necessarily of the same tariff class *c*.[30]

United Energy submitted that the side constraint formula should use the term 'p' rather than 'd' to avoid confusion and be consistent with the WAPC formula. United Energy also stated that the formula should be modified to ensure tariff class reassignments are not constrained by the side constraint formula.[31]

4.2.1.7 Changes to tariff structures

CitiPower and Powercor considered that appendix E.1 of the draft determination is not workable in relation to determining the values of q_{t-2}^{ij} and p_{t-1}^{ij} for the WAPC and side constraint formulae. CitiPower and Powercor commented that this issue is more significant in Victoria than in other jurisdictions where the AER has applied the formulae because of likely significant reassignment of customers to new tariffs in the forthcoming regulatory control period due to the roll out of AMI meters.[32]

CitiPower, Powercor and SP AusNet expressed concern regarding the requirements in appendix E.1.1 of the draft decision relating to the reasonable estimates of quantities when introducing new tariffs or tariff components. [33] CitiPower and Powercor commented that this will result in estimates that are not realistic if there is a customer response to the change in tariffs which is likely with the introduction of time of use (TOU) tariffs and is inconsistent with the pricing principles set out in clause 6.18.5 of the NER.[34] Similarly SP AusNet commented that the requirement that reasonable estimates of *t–2* quantities equal the actual audited quantities for the origin tariff/tariff components does not enable the Victorian DNSPs to take into account the elasticity of demand impacts of a new tariff in particular TOU tariffs. SP AusNet considered that this leaves the Victorian DNSPs' revenue at risk in relation to tariff reassignments,

30 These definitions are taken from CitiPower, *Revised regulatory proposal*, pp. 76–77. Similar definitions can be found in: Powercor, *Revised regulatory proposal*, pp. 71–72; JEN, *Revised regulatory proposal*, pp. 26–27; SP AusNet, *Revised regulatory proposal*, pp. 377–378.

31 United Energy, *Revised regulatory proposal*, p. 282.

32 CitiPower, *Revised regulatory proposal*, p. 78; Powercor, *Revised regulatory proposal*, p. 72.

33 CitiPower, *Revised regulatory proposal*, p. 78; Powercor, *Revised regulatory proposal*, p. 72; SP AusNet, *Revised regulatory proposal*, pp. 366–368.

34 CitiPower, *Revised regulatory proposal*, p. 78–79; Powercor, *Revised regulatory proposal*, p. 72–73.

particularly when transferring customers from a flat tariff to a TOU tariff. SP AusNet noted that if the lower revenues are not reflected in the demand forecasts for the 2011-15 regulatory control period and the P_0 adjustment, the Victorian DNSPs will be worse off from a revenue perspective.[35] SP AusNet also considered that the reductions in costs due to reduced consumption (due to higher TOU tariffs, for example) will not be commensurate with the reductions in revenue because prices reflect the long run marginal cost for the service.[36]

SP AusNet stated that the AER needs to explicitly state that the requirement in page 9 point 2 of appendix E of the draft decision does not prescribe the use of the origin tariffs' average consumption profile, but rather allows for specific consumption profiles to be developed for those customers expected to transfer from a flat tariff to a TOU tariff. SP AusNet considered that this is necessary because the draft decision as it stands can be misinterpreted as prescribing the use of the origin tariff's average consumption profile in deriving reasonable estimates of q_{t-2}^{ij}, which may affect SP AusNet's revenue particularly when the uptake of the TOU is voluntary.[37]

Given these issues, SP AusNet stated that appendix E of the draft decision only works if:

- SP AusNet is compensated through the P_0 adjustment for customers moving from a flat tariff to a TOU tariff; or
- if appendix E was changed such that the derivation of quantities in year *t–2* for the numerator of the WAPC formula is based on 'reasonable estimates…of the quantities that would have been sold if the new tariff/tariff components had been introduced in year *t–2*'.[38]

SP AusNet proposed that the AER adopt the latter option.[39]

Similarly CitiPower and Powercor proposed amending appendix E.1 such that estimates for q_{t-2}^{ij} reflect the demand response resulting from the tariff reassignment.[40]

CitiPower and Powercor proposed amending appendix E.1 of the draft decision to remove the requirement that the value of p_{t-1}^{ij} be set to zero if the origin tariff and new tariff do not have the same unit of measure as this requirement distorts the application of the WAPC and side constraint formulae. CitiPower and Powercor considered that in such a situation the appendix should provide for the use of an appropriate conversion factor taking into account the expected behavioural response.[41]

35 SP AusNet, *Revised regulatory proposal*, pp. 366–368.
36 ibid., p. 368.
37 ibid., p. 369.
38 ibid., p. 368.
39 ibid., p. 374.
40 CitiPower, *Revised regulatory proposal*, p. 79; Powercor, *Revised regulatory proposal*, p. 73.
41 CitiPower, *Revised regulatory proposal*, p. 79–80; Powercor, *Revised regulatory proposal*, p. 73–74.

SP AusNet also considered that the non-inclusion of 'customers who request to change tariff either voluntarily, or through the actions of a retailer' in the calculation of reasonable estimates of q_{t-2}^{ij} inhibits SP AusNet's ability to provide incentives to customers to transfer off closed tariffs.[42]

4.2.1.8 Rounding

SP AusNet commented that the requirement in the draft decision to round each of the percentage factors in the WAPC and side constraints formulae is inconsistent with common practice. SP AusNet considered there are no demonstrable administrative costs in dealing with actual, as opposed to rounded, input numbers.[43] United Energy proposed that inputs into the WAPC and side constraint formulas be rounded to four decimal places, and that outputs should be rounded so that results are not biased one way or another.[44]

4.2.2 Recovery of transmission tariffs

4.2.2.1 Transmission related payments[45]

CitiPower and Powercor did not accept the AER's draft decision not to include a mechanism to recover transmission related costs. CitiPower and Powercor proposed to include new terms in the WAPC and side constraint formulae to address the recovery of transmission related costs (TRC_t) and a factor to close out the correction factor K_t in the MTR formula specified in the 2006 EDPR (KAY_t).[46] CitiPower and Powercor commented that without this term the Victorian DNSPs will incur costs they cannot recover through any mechanism, which would be inconsistent with the national electricity objective and the revenue and pricing principles in the National Electricity Law (NEL).[47]As discussed above, CitiPower and Powercor also considered that clause 6.12.3(c) of the NER does not prevent the AER from adding new terms such as TRC_t in the WAPC formula.[48]

CitiPower, Powercor and JEN noted United Energy's proposed rule change to the AEMC on 22 June 2010 made on behalf of all Victorian DNSPs. CitiPower, Powercor and JEN commented that there is a high probability that the rule change will not be completed prior to the AER's final decision.[49] CitiPower and Powercor commented that this rule change may not automatically provide a mechanism to recover those transmission related payments.[50] JEN recommended that the AER consult on the

42 SP AusNet, *Revised regulatory proposal*, p. 370.
43 ibid., p. 375.
44 United Energy, *Revised regulatory proposal*, p. 282.
45 'Transmission related payments (or charges)' is used in this final decision as the collective term for transmission use of system (TUOS) payments, transmission connection payments avoided TUOS payments, and inter-DNSP payments.
46 CitiPower, *Revised regulatory proposal*, pp. 60, 61, 69, 73 and 74; Powercor, *Revised regulatory proposal*, pp. 56, 57, 64–65, 68 and 69.
47 CitiPower, *Revised regulatory proposal*, p. 69; Powercor, *Revised regulatory proposal*, pp. 64.
48 CitiPower, *Revised regulatory proposal*, pp. 67–69; Powercor, *Revised regulatory proposal*, pp. 63–64.
49 CitiPower, *Revised regulatory proposal*, pp. 66–67 and 70; Powercor, *Revised regulatory proposal*, pp. 62 and 65; JEN, *Revised regulatory proposal*, p. 34.
50 CitiPower, *Revised regulatory proposal*, pp. 71–72; Powercor, *Revised regulatory proposal*, pp. 66–67

recovery mechanism for transmission connection costs, inter-DNSP charges and avoided TUOS.[51] United Energy commented that the NER and the NEL should be re-examined to determine whether there is a course of action available to the AER to provide certainty regarding the recovery by the Victorian DNSPs of transmission connection charges and inter-DNSP charges.[52]

JEN stated that the maximum transmission revenue (MTR) mechanism specified in the draft decision does not comply with clause 7A(2)(a) of the NEL which provides that DNSPs should be able to recover efficient costs associated with direct control services.[53] JEN and SP AusNet recommended that the AER establish a control mechanism to allow for recovery of pass through amounts from tariffs that are separate to the distribution use of system (DUOS) tariffs. The dedicated pass through control mechanism proposed by JEN and SP AusNet is as follows:

$$MPR_t = PC_t - K_t$$

where

> MPRt (in ¢) is the maximum revenue a distribution business is allowed to receive from its pass through tariffs from all distribution customers for the calendar year *t*;
>
> PCt (in ¢) is the aggregate amount of all positive and negative change events approved for pass through which the distribution business forecasts will be payable or receivable in year *t* where amounts comply with any relevant guidance in force from time to time or are required under any jurisdictional legislation or regulation;
>
> Kt (in ¢) is a correction factor.[54]

Under JEN's and SP AusNet's proposal network use of system (NUOS) tariffs would comprise DUOS tariffs, transmission related tariffs and pass through tariffs according to JEN, or DUOS tariffs and pass through tariffs according to SP AusNet.[55]

SP AusNet considered that there is no impediment to the AER adopting such a MPR control mechanism, that it has several advantages over including the pass through parameter in the WAPC formula (such as the volumetric risk associated with the possible adoption of the VBRC recommendations in the forthcoming regulatory control period), and better supports the objectives of the NER and NEL.[56]

If the AER does not accept these proposals, CitiPower, Powercor and JEN stated that their respective forecasts of transmission related payments (except TUOS) should be included in forecast opex with provision for annual unders and overs pass throughs

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51 JEN, *Revised regulatory proposal*, p. 34.

52 United Energy, *Revised regulatory proposal*, pp. 279 and 281.

53 JEN, *Revised regulatory proposal*, p. 34.

54 JEN, *Revised regulatory proposal*, Appendix 4.4, 20 July 2010; SP AusNet, *Revised regulatory proposal*, pp. 378–381.

55 JEN, *Revised regulatory proposal*, Appendix 4.4, 20 July 2010, p. 3; SP AusNet, *Revised regulatory proposal*, p. 378.

56 SP AusNet, *Revised regulatory proposal*, pp. 375–376.

with no materiality threshold.[57] CitiPower and Powercor stated that a non-zero materiality threshold will reassign risk from customers to DNSPs.[58] SP AusNet stated that the latest estimate of these payments should be reviewed and included in the AER's final decision.[59]

CitiPower and Powercor commented that transmission related costs are incurred in providing direct control network services and complying with regulatory obligations. Accordingly the AER is required by clause 6.5.6(c) of the NER to accept these opex forecasts if the AER rejects CitiPower's and Powercor's proposed WAPC and/or side constraint terms.[60]

United Energy commented that transmission connection charges fall within the definition of ‘direct control services’ under the NER and the NEL.[61] If its proposed rule change is not passed in time for the Victorian DNSPs' pricing proposals, United Energy recommended that the distribution determination allow recovery of transmission related charges, including overs and unders, noting that these charges should not be regulated by the control mechanism set out in the determination (that is, amend the WAPC formula to account for the recovery of transmission connection charges). If this is not accepted, United Energy proposed recovering these charges through a pass through provision with a zero materiality threshold. Otherwise, United Energy proposed recovering these charges as an opex allowance.[62]

4.2.2.2 Premium feed-in tariff

CitiPower and Powercor noted that the new clause 6.18.7A of the NER made by the AEMC on 1 July 2010 will allow CitiPower and Powercor to recover premium feed-in tariff (PFIT) payments. Accordingly an additional term is not required to be introduced to the WAPC formula to address PFIT payment recovery.[63]

JEN considered that the AER's draft decision relating to PFIT payments does not comply with the NEL requirement that DNSPs be provided with an opportunity to recover its efficient costs and that the AER must specify a means to recover these costs. JEN considered that PFIT payments should be recovered through its proposed MPR mechanism, which JEN considered is supported by the 1 July 2010 AEMC rule determination *National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010*.[64]

United Energy noted the Victorian DNSPs' obligations under the Electricity Industry Act in Victoria to pay PFIT in the forthcoming regulatory control period and that regulated network service providers should be provided with a reasonable opportunity to recover at least efficient costs in complying with regulatory obligations under clause 7A of the NEL. United Energy commented that the AER's position in the draft

57 CitiPower, *Revised regulatory proposal*, pp. 60, 70 and 72–73; Powercor, *Revised regulatory proposal*, pp. 56, 65 and 67–68; JEN, *Revised regulatory proposal*, p. 34.
58 CitiPower, *Revised regulatory proposal*, p. 73; Powercor, *Revised regulatory proposal*, p. 68.
59 SP AusNet, *Revised regulatory proposal*, p. 373.
60 CitiPower, *Revised regulatory proposal*, pp. 70–71; Powercor, *Revised regulatory proposal*, p. 66.
61 United Energy, *Revised regulatory proposal*, pp. 279-280.
62 ibid., pp. 280–281.
63 CitiPower, *Revised regulatory proposal*, p. 66; Powercor, *Revised regulatory proposal*, p. 62.
64 JEN, *Revised regulatory proposal*, p. 35.

decision regarding PFIT is at odds with the objective to ensure that businesses are provided the opportunity to recover at least efficient costs incurred.[65]

4.2.2.3 Maximum transmission revenue control correction factor Kz_t

CitiPower and Powercor stated that the reference to TRa_{t-1} in the calculation of Kzt in appendix F.2.5 of the draft decision should be TRa_{t-2}.[66]

4.2.3 Tariff class assignment procedures

4.2.3.1 Issues with notification of tariff assignment for customer connections

Regarding clause 6 of the tariff class assignment procedures (the procedures) CitiPower, Powercor, JEN and SP AusNet considered that there are implementation issues in relation to notification of tariff class assignments (but not reassignment).[67]

CitiPower, Powercor and JEN stated that customers have either implicitly or explicitly agreed to the network tariff where customers are afforded the ability to question and/or dispute the initial assignment. Therefore, there is no need for the DNSP to provide notice of tariff assignment. For example, small business customers seeking new connections generally approach their retailer who bundle network tariffs with their customers' retail tariff. Large customers explicitly agree to their network tariff assignment as they directly negotiate with the DNSP regarding tariff classes. CitiPower, Powercor and JEN further stated that a requirement to notify the customer of assignment may confuse customers given they have notified their retailer to arrange energisation and entered into a retail contract.[68]

SP AusNet stated that this clause would require it to make approximately 130 000 notifications of tariff assignments when customers occupy new premises or there is a change of occupant in an existing premises (on top of the tariff reassignment notifications required in the current regulatory control period).[69]

CitiPower, Powercor, JEN and SP AusNet have included estimates of costs associated with meeting clause 6 of the tariff class assignment procedures (included in the opex step change calculations) if the AER does not amend the clause.

CitiPower and Powercor proposed to amend clause 6 of the procedures as follows:

> (a) A Victorian DNSP must notify the customer concerned in writing of the tariff class to which the customer will be reassigned by it prior to the reassignment occuring.
>
> (b) A customer may apply for reassignment of their tariff class.[70]

JEN proposed to amend clause 6 of the procedures as follows:

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65 United Energy, *Revised regulatory proposal*, p. 281.
66 CitiPower, *Revised regulatory proposal*, p. 78; Powercor, *Revised regulatory proposal*, p. 72.
67 CitiPower, *Revised regulatory proposal*, pp. 61 and 80; Powercor, *Revised regulatory proposal*, pp. 57 and 74.
68 CitiPower, *Revised regulatory proposal*, pp. 80–81; Powercor, *Revised regulatory proposal*, p. 75; JEN, *Revised regulatory proposal*, p. 29.
69 SP AusNet, *Revised regulatory proposal*, p. 370.
70 CitiPower, *Revised regulatory proposal*, p. 82; Powercor, *Revised regulatory proposal*, p. 76.

> (a) A Victorian DNSP must notify the customer concerned in writing of the tariff class to which the customer has been reassigned.
>
> (b) A customer may apply for reassignment of their tariff class.[71]

SP AusNet proposed the following amendment to clause 6 of the procedures:

> A Victorian DNSP must notify the distribution customer's retailer in writing of the distribution tariff to which the distribution customer has been reassigned, prior to the reassignment occuring.[72]

4.2.3.2 Dispute resolution through the EWOV

CitiPower, Powercor, JEN and SP AusNet stated that the involvement of the Energy and Water Ombudsman (Victoria) (EWOV) in clause 7.b. of the procedures is unnecessary and costly and suggested that it be removed.[73] CitiPower, Powercor and SP AusNet noted the arrangements under the 2006 EDPR in which tariff reassignment disputes were referred to the ESCV or the AER.[74]

CitiPower and Powercor stated that the EWOV is not resourced to handle network tariff assignment complaints.[75]

JEN stated that if the AER retains EWOV involvement in the procedures, DNSPs must be compensated for the costs incurred and has included these costs in calculating step changes.[76]

SP AusNet has not included these costs as a step change as 'it strongly considers that it is unreasonable for the AER to include this step into the process' and proposed an amendment to the procedures such that the AER is the dispute resolution body. SP AusNet commented that many objections of a frivolous nature would be raised in the forthcoming regulatory period because of reassignments following the rollout of AMI.[77] However, SP AusNet stated that if EWOV involvement is retained in the procedures, then it should be given the efficient costs relating to this obligation in the final decision.[78]

4.2.3.3 Customer notification for AMI time of use tariff reassignments

In the draft decision, clause 15 of the procedures required the Victorian DNSPs to notify customers with an interval meter of reassignment to a TOU tariffs prior to reassignment. JEN considered that the prime responsibility for informing customers about assignment and reassignments must sit with retailers as it is up to the retailer as to how and to what extent the impact of moving to a given distribution tariff

71 JEN, *Revised regulatory proposal*, p. 31.
72 SP AusNet, *Revised regulatory proposal*, p. 371.
73 CitiPower, *Revised regulatory proposal*, pp. 61 and 82–83; Powercor, *Revised regulatory proposal*, pp. 57 and 76–77; JEN, *Revised regulatory proposal*, p. 32; SP AusNet, *Revised regulatory proposal*, p. 371.
74 CitiPower, *Revised regulatory proposal*, pp. 61 and 82–83; Powercor, *Revised regulatory proposal*, pp. 57 and 76–77; SP AusNet, *Revised regulatory proposal*, p. 371.
75 CitiPower, *Revised regulatory proposal*, p. 83; Powercor, *Revised regulatory proposal*, p. 77.
76 JEN, *Revised regulatory proposal*, p. 32.
77 SP AusNet, *Revised regulatory proposal*, p. 371.
78 ibid., p. 371.

(including TOU) is reflected in the retail price. Therefore this obligation should be amended to specify notification of a customer's retailer.[79]

4.2.3.4 Tariff reassignment

Citing clauses 1 and 5 of the procedures, SP AusNet stated that the procedures do not have the flexibility to enable DNSPs to adopt innovative tariffs and may lock in sub-optimal tariffs. SP AusNet referred to the example of reassignment to its proposed Critical Peak Demand tariff as not being able to be justified due to a change in a customer's load and/or connection characteristics. Further, SP AusNet commented that there is no exception to the requirement that customers must retain exactly the same tariff they are on as at 1 January 2011. SP proposed including flexibility in the procedures to better reflect the pricing principles in clause 6.18.5 of the NER.[80]

4.2.3.5 Tariff reassignment assumptions and price path calculation

JEN has incorporated the draft decision requirement to apply the net present value price path calculation in the PTRM assuming no tariff reassignments. JEN understands that the draft decision does not intend this requirement to constrain a DNSP's ability to reassign customers or to recover their allowed revenue requirements given future reassignments. JEN submitted a model showing how it understands foregone revenues associated with tariff reassignments are recovered using JEN's proposed amendments to the WAPC and side constraint formulae.[81]

4.3 Submissions

4.3.1 Weight average price cap

4.3.1.1 Tariff setting and approval process

Origin Energy Electricity Limited (Origin) commented that the assumptions each DNSP makes regarding TOU tariffs and the WAPC will have an impact on revenue and on price outcomes relative to X factors. Origin stated that the pricing approval process is not transparent so retailers are unable to assess these assumptions. Origin asked whether the AER could gather information from DNSPs regarding assumptions behind substitute values in the WAPC and TOU tariffs and if the AER could share this information with retailers.[82]

The Consumer Utilities Advocacy Centre (CUAC) commented that there is limited time available for the network tariff approval process. The CUAC proposed a more collaborative process to tariff approvals involving cooperation and consultation between DNSPs, consumer groups and the AER.[83]

The Energy Users Association of Australia (EUAA) raised similar concerns and noted that the AER previously wrote to the CEOs of network businesses concerned asking

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79 JEN, *Revised regulatory proposal*, p. 33.

80 SP AusNet, *Revised regulatory proposal*, pp. 372–373.

81 JEN, *Revised regulatory proposal*, p. 33; JEN, *Revised regulatory proposal*, Appendix 4.2, 20 July 2010.

82 Origin, *Victorian electricity distribution draft determination and revised proposals,* 19 August 2010, p. 4.

83 CUAC, *Submission in response to the AER draft electricity distribution determination for Victoria and the distribution businesses revised revenue proposals*, 19 August 2010, pp. 2–3.

them to improve their consultation with users on tariff changes and begin this process earlier. The EUAA noted that it is unaware of such consultation having been undertaken with the Victorian DNSPs.[84]

4.3.1.2 Side constraints

The Victorian Minister for Energy and Resources (the Minister) sought confirmation that side constraints will apply to distribution tariffs in 2011. The Minister noted that side constraints applied to distribution tariffs for the first year of the current regulatory control period and stated that clause 6.18.6(b) of the NER did not prevent the application of side constraints in the first year of a regulatory control period.[85]

4.3.2 Recovery of transmission tariffs

4.3.2.1 Transmission related payments

EnergyAustralia commented that the approach to the recovery of transmission related payments for the Victorian DNSPs should be consistent with the approach applied in New South Wales in which the AER allowed the recovery of TUOS charges as well as transmission connection charges, inter-DNSP charges and avoided TUOS charges in making its constituent decision under clause 6.12.1(19) of the NER.[86]

4.3.2.2 Premium feed-in tariffs (PFIT)

The Minister noted the AEMC's rule change relating to PFIT payments which considered that the administration costs relating to PFIT schemes would be within the requirements for operating expenditure under the NER.[87]

4.3.3 Tariff class assignment procedures

Origin commented that appendix G of the draft decision addresses a situation where a customer's circumstances dictate that their network tariff must change, but not a situation where the distributor (DNSP) is offering premium services or other arrangements to a customer or to seek a return in excess of the regulated return. The latter scenarios would require the customer's consent, the full set of customer protection arrangements and arrangements to modify the final bundled tariff.[88]

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84 EUAA, *AER draft determination on Victorian electricity distribution prices for the period 2011–2015 and distributors' revised proposals*, 19 August 2010, pp. 11–12.

85 Minister for Energy and Resources (Victoria), *Submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–15*, 20 August 2010, p. 10.

86 EnergyAustralia, *EnergyAustralia submission on AER draft regulatory determination for Victorian distributors*, 19 August 2010, p.19.

87 Minister for Energy and Resources (Victoria), *Submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–15*, 20 August 2010, p. 11; AEMC, *Rule determination National electricity amendments (Payments under feed-in schemes and climate change funds) rule 2010*, 1 July 2010, p. 15.

88 Origin, *Submission to the AER*, p. 5.

4.4 Issues and AER considerations

4.4.1 Weighted average price cap formula

4.4.1.1 Licence fee (L_t) factor

The AER notes that page 57 of the draft decision contains the statement "[a]s previously mentioned, the AER will carry over adjustments arising from the licence fee factor" and recognises that this statement may have been the cause of some confusion regarding the AER's approach on this matter. In this final decision, the AER clarifies that licence fees paid in 2010 will be recovered in 2011 under the price control.

The AER has clarified the operation of the L_t factor in the draft decision with JEN, CitiPower and Powercor.[89] JEN, CitiPower and Powercor have agreed with the specification of the L_t factor in the draft decision.[90]

AER conclusion

The calculation of L_t for the forthcoming regulatory control period is set out in appendix E of this final decision.

4.4.1.2 S factor true up

The AER's consideration of the S factor true up is in chapter 15 of this final decision.

Regarding the AER's ability to amend the specification of the control mechanism under clause 6.12.3(c) of the NER, CitiPower and Powercor noted the following statement from the SA draft decision:

> Clause 6.8.1, in conjunction with clause 6.12.3(c), of the NER does not allow the form of control mechanism that applies to ETSA Utilities to be varied from that specified in the framework and approach (that is a WAPC cannot be changed to a revenue cap). However, the AER considers that the WAPC formula can be amended where this would reflect (or better reflect) the reasoning set out in the framework and approach.[91]

The AER points to the Victorian Framework and approach paper which stated:

> …the AER notes that benefits and penalties accrued in the current regulatory control period under the ESCV scheme will not be incorporated in the price cap formula. Rather, financial carryover amounts from the current regulatory control period will be included as a building block element in the calculation of allowed revenue for the next regulatory control period.[92]

89 AER, *Licence fee factor specification*, email to JEN, CitiPower and Powercor, 18 August 2010.

90 CitiPower and Powercor, *RE: Licence fee factor specification*, email to AER, 23 August 2010; JEN, *JEN 2011–15 regulatory proposal: Weighted average price control and L factor*, email to AER, 26 August 2010.

91 AER, *South Australia draft distribution determination 2010–11 to 2014–15*, Draft decision, 25 November 2009, pp. 42–43.

92 AER, *Framework and approach paper*, p. 94.

The AER considers that the inclusion of the S factor true up in the WAPC formula is not consistent with the reasoning set out in the Framework and approach paper and with the requirements of clause 6.12.3(c).

CitiPower and Powercor noted several differences between the WAPC specification in the draft decision and the Framework and approach.[93] Regarding these changes the AER notes the following:

- The AER considers that the control mechanism for standard control services is the appropriate (and only) mechanism for the recovery of pass through costs under the NER, hence the AER added the $\pm\ passthrough_t$ parameter which was not included in the WAPC formula in the Framework and approach paper (see section 4.4.1.5 below). If the AER did not do this, cost pass through could not, as is envisaged in the NER, comprise an adjustment to the building block determination for standard control services. The pass through parameter must be contained in the control mechanism.

- The AER amended the definition of CPI because the definition contained in the Framework and approach was incomplete.[94] The correct definition which appeared in the draft decision and appears in section 4.5.1 of this final decision reflects the reasoning set out (what was intended) in the Framework and approach paper.

- The AER considers that the definition of the licence fee factor set out in the draft decision is consistent with the definition set out in the Framework and approach paper.

AER conclusion

As discussed in chapter 15 of this final decision, the AER considers that it is appropriate for the Victorian DNSPs to recover the true up for actual 2010 performance under the ESCV S factor scheme in the 2016–20 regulatory control period.

4.4.1.3 S factor specification

Victorian DNSP revised regulatory proposals

The AER's consideration of the S factor specification is in chapter 15 of this final decision.

AER conclusion

As discussed in chapter 15 of this final decision, consistent with the AER's previous distribution determinations the specification of the S factor for the control mechanism for standard control services is provided for in the AER's STPIS.[95]

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93 CitiPower, *Revised regulatory proposal*, p. 68; Powercor, *Revised regulatory proposal*, pp. 63–64.

94 AER, *Draft decision*, pp. 61–62.

95 AER, *Electricity distribution network service providers Service target performance incentive scheme*, November 2009.

4.4.1.4 WAPC formula specification

The AER has considered the left hand side of the WAPC formula proposed by the Victorian DNSPs and has further consulted with the DNSPs to gain a better understanding of the application of the proposed formula. The AER notes that the amendment proposed by the DNSPs to the left hand side of the WAPC formula is intended to provide greater clarity when accounting for changes to tariff structures such as tariff reassignment.

However the AER notes that clause 6.12.3(c) of the NER states that the control mechanism to apply to the Victorian DNSPs for the forthcoming regulatory period 'must be as set out in the relevant framework and approach paper.'

Further the AER considers that the left hand side of the WAPC formula as set out in the Framework and approach paper and the draft decision is sufficiently flexible to account for changes to tariff structures including tariff reassignments. The left hand side of the WAPC formulae in the most recent price resets of jurisdictional regulators in Victoria and NSW are identical to the left hand side of the WAPC in the draft decision.[96] The AER has also adopted this formula in its distribution determinations for NSW and SA. It does not appear that the left hand side of the WAPC formula in the draft decision has been an impediment to the calculation of the WAPC in the regulatory periods in which the ESCV and IPART have been the jurisdictional regulators, nor in the ongoing regulatory control periods under the AER's distribution determinations for NSW and SA, when changes to tariff structures including tariff reassignments occur.

AER conclusion

The WAPC and side constraint formulae to apply to the Victorian DNSPs in the forthcoming regulatory control period are specified in sections 4.5.1 and 4.5.2 of this final decision

4.4.1.5 Pass through parameter

Victorian DNSP revised regulatory proposals

In relation to the MPR mechanism proposed by JEN and SP AusNet, chapter 6 of the NER provides for a DNSP to recover costs through the distribution determination process under Part C, where the AER determines the annual revenue requirement for each regulatory year of the regulatory control period. Part C of chapter 6 of the NER provides for the recovery of pass through costs as adjustments that may be made to a building block determination. The AER considers that cost pass throughs are intended to be an adjustment to a building block determination under chapter 6 of the NER and are therefore to be recovered through the control mechanism for direct control services.

[96] ESCV, *Electricity distribution price review 2006–10*, Final decision volume 2, December 2008, p. 12; IPART, *NSW electricity distribution pricing 2004/05 to 2008/09*, Final determination, June 2004, p. 6.
Note that the left hand side of IPART's WAPC formula differs only in form to the ESCV's and the draft decision's WAPC formula, e.g. the year "t" is depicted in IPART's formula as "t+1". The calculations of the formulae are otherwise identical.

Part I of chapter 6 of the NER considers the distribution pricing rules. Clause 6.18.1 of the NER provides that Part I applies to tariffs and tariff classes related to direct control services. For example, clauses 6.18.7 and 6.18.7A allow for the recovery of TUOS charges and jurisdictional scheme amounts. As the pass through provisions and the distribution pricing rules appear in different Parts of the NER, the AER considers that the NER does not allow for the recovery of general pass through amounts through a dedicated mechanism such as the MPR proposed by JEN and SP AusNet.

The AER has considered the use of the multiplicative pass through factor proposed by the Victorian DNSPs.

However the AER considers that the additive pass through factor outlined in the draft decision simplifies the application and analysis of the WAPC and side constraint formulae compared to a multiplicative term. The pass through term is additive so that the distributor can demonstrate how the pass through allowance is to be recovered across the tariff classes and components. This is done by converting the total pass through amount to incremental charges, using forecast quantities for year *t*.

This avoids a complex conversion of dollar amounts into percentage terms, and the effects of a pass through amount in one year do not need to be removed in the next year. This reduces administrative costs and the regulatory burden on Victorian DNSPs and the AER.

The additive pass through parameter is also consistent with the approach used in the AER's distribution determinations for NSW/ACT and SA/QLD.

JEN and SP AusNet considered that pass through costs should be subject to a true up mechanism with SP AusNet referring to the requirement in clause 6.6.1(j)(5) of the NER that the DNSP 'only recovers any actual or likely increment in costs…to the extent that such increment is solely as a consequence of a pass through event.'[97] As stated above approved pass through amounts are converted into incremental charges using forecast quantities in a Victorian DNSP's pricing proposal. This leads to the possibility that the DNSP could over-recover or under-recover its costs relative to the approved pass through amount. The AER therefore considers that a true up mechanism for pass through costs is appropriate to ensure that the DNSP recover only the pass through amounts approved by the AER. The mechanism to calculate the pass through incremental charges including the true up is included in appendix E of this final decision.

AER conclusion

The AER has amended the definition of the $passthrough_t$ parameter in sections 4.5.1 and 4.5.2 of this final decision to clarify its application in the WAPC and side constraint formulae.

[97] JEN, *RE: Pass through parameter in WAPC and side constraint formulae*, email to AER, 6 October 2010; SP AusNet, *Re: Fw: Pass through parameter in WAPC and side constraint formulae*, email to AER, 5 October 2010.

4.4.1.6 Side constraints

Victorian DNSP revised regulatory proposals

The AER has considered the left hand side to the side constraint formula proposed by the Victorian DNSPs. The AER notes that the amendment proposed by the DNSPs to the left hand side of the side constraint formula is intended to provide greater clarity when accounting for changes to tariff structures such as tariff reassignment. The AER notes that the amendment to the left hand side of the side constraint formula as proposed by the Victorian DNSPs is consistent in form with their proposed amendment to the left hand side of the WAPC formula.

As discussed in section 4.4.1.4 the AER has not adopted the left hand side of the WAPC formula proposed by the Victorian DNSPs. To ensure consistency between the WAPC and side constraint formulae and to avoid confusion, the AER has not adopted the side constraint formula proposed by the Victorian DNSPs and has instead adopted a formula that is consistent with the WAPC formula. This is discussed further below.

The AER notes the comment from SP AusNet and United Energy that the side constraint in section 4.6.2 of the draft decision appears to apply at the tariff level whereas clause 6.18.6 of the NER requires the side constraint to apply at the tariff *class* level.

The AER considers that the side constraint set out in section 4.6.2 of the draft decision can apply at the tariff class level. The AER understands that a tariff class in practice can contain several tariffs with their associated components (where different customers within the same tariff class may be assigned to different tariffs). Using the side constraint the AER applied for South Australia, each tariff class contains *m* distribution tariff components summed over all tariffs.[98] The AER notes that the side constraint formula for the South Australian distribution determination does not require that a tariff component be associated with a tariff and this does not affect the operation of the side constraint.

For greater clarity however the AER has amended the side constraint formula as set out in section 4.5.2 of this final decision to ensure greater transparency regarding the tariffs (and their components) in a tariff class.

The AER notes United Energy's comment that the side constraint formula should use 'p' rather than 'd' to avoid confusion and be consistent with the WAPC formula. The AER has adopted this approach in the side constraint in section 4.5.2 of this final decision.

JEN proposed that where customer reassignments occur across tariff classes there should be an adjustment to the application of the side constraint. JEN stated that not doing so would constrain movements between tariff classes because in some cases this would result in the need to change the price faced by existing customers on the tariff to which the customers are reassigned even where these tariffs are already set at an efficient level.[99] The example JEN gave was where a small customer becomes a

98 AER, *South Australian distribution determination 2010–11 to 2014–15, Final decision*, p. 27.

99 JEN, *100915 JEN response to AER request on price control and side constraint*, Attachment 3, 15 September 2010, p. 3.

large customer and is reassigned (subject to the customer classification provisions) to a large customer tariff class. In such circumstances, the lower origin tariff associated with the customer's previous small scale operation would mean that the prices for existing large customers may have to be reduced to remain within the side constraint, other things being equal. To prevent such an outcome JEN proposed that when a tariff class reassignment occurs, the p_{t-1}^{ij} term associated with the customer being reassigned should be set equal to:

- for the WAPC, the origin tariff in year *t–1*
- for the side constraint, the tariff in year *t–1* of the tariff class the customer is being reassigned to, except for reassignment to a newly created tariff class
- for a new tariff class, the origin tariff in year *t–1*.[100]

JEN considered that its approach regarding side constraints would avoid inefficient limits on tariff rebalancing across tariff classes.

The AER agrees with JEN that the movement of customers across tariff classes should not result in it having to alter tariffs faced by existing customers where those tariffs reflect efficient pricing. The AER notes that a tariff reassignment can occur within a tariff class. However, such reassignments do not require the origin tariff to be redefined as such customer movements remain with the bundle of tariffs to which the side constraint applies. The AER therefore considers that, where a tariff reassignment occurs across tariff classes, p_{t-1}^{ij} in the side constraint should equal the tariff in year *t–1* of the tariff class to which the customer has been assigned. An exception exists where the reassignment is to a new tariff across tariff classes. In this case, p_{t-1}^{ij} in the side constraint should equal the origin tariff price in year *t–1*. The AER has amended appendix E.1.2 of the draft decision to reflect this.

The AER considers that this amendment to the draft decision is consistent with clause 6.18.6 of the NER, which requires the AER to compare the weighted average price the DNSP proposes to raise from a particular tariff class for the forthcoming regulatory year, against the corresponding weighted average price raised from that tariff class for the previous regulatory year. The AER considers that setting p_{t-1}^{ij} to equal the tariff in year *t–1* of the tariff class the customer is being reassigned to is an appropriate method to make this comparison.

In the draft decision the AER requested that the Victorian DNSPs remove the impact of assumed tariff reassignments, in particular those related to the introduction of AMI, in the calculation of X factors. The AER considered that tariff reassignments are more appropriately considered in the Victorian DNSPs' pricing proposals. The AER has maintained this approach for this final decision (see chapter 18). As discussed in chapter 5, the impact of AMI has been incorporated in the energy forecasts.

The AER notes that prices proposed by the Victorian DNSPs in regulatory year *t* in the forthcoming regulatory control period must meet the constraints of both the

[100] JEN, *Response to AER information request of 8 October 2010*, Attachment 2, 12 October 2010, p. 5.

control mechanism for standard control services (the WAPC) and the side constraint under clause 6.18.6 of the NER and this final decision.

Submissions

In relation to the Minister's submission, the AER considers that the side constraints as set out in clause 6.18.6 of the NER do not apply in 2011 because the 2006–10 regulatory period was under a different regulatory regime. Clause 6.18.6(b) of the NER provides that '[t]he expected weighted average revenue to be raised from a tariff class for a particular regulatory year of a regulatory control period must not exceed the corresponding expected weighted average revenue for the preceding regulatory year by more than the permissible percentage.' Regulatory year is defined, in essence, in chapter 10 of the NER as being in a regulatory control period. The term, regulatory control period, also defined in Chapter 10 of the NER, is 'a period of not less than 5 regulatory years for which the provider is subject to a control mechanism imposed by a distribution determination.' Distribution determination is relevantly defined in s. 2 of the NEL as a determination of the AER. As this is the first distribution determination of the AER for Victorian DNSPs, there is no previous regulatory control period or regulatory year that allows for the application of side constraints in accordance with clause 6.18.6(b) of the NER. Therefore, the AER does not have the authority under the NER to apply side constraints to distribution tariffs in 2011. Further, the AER notes that the side constraints under the 2006 EDPR applied at the tariff level, whereas clause 6.18.6 of the NER requires that side constraints apply at the tariff class level.[101]

AER conclusions

The side constraints formula to apply to tariff classes related to the provision of standard control services is outlined in section 4.5.2 of this final decision.

4.4.1.7 Changes to tariff structures

Victorian DNSP revised regulatory proposals

Chapter 5 of this final decision details the AER's consideration of the impact of TOU tariffs on energy consumption as raised by CitiPower, Powercor and SP AusNet. As explained in chapter 5 the AER will account for the demand response to the introduction of TOU tariffs in the demand forecasts and not through the control mechanism and side constraint for standard control services.

In response to CitiPower's and Powercor's respective revised regulatory proposals, the AER has amended clause E.1.1.2 of the draft decision to allow for the use of a conversion factor when the origin tariff and the new tariff do not have the same unit of measure. This is limited to instances where a conversion factor can be derived, for example where the origin tariff is measured in kW and the new tariff is measured in kVa. Where no conversion factor can be derived, the AER has retained the requirement that p_{t-1}^{ij} be set to zero consistent with the distribution determinations for NSW, ACT and SA.

Regarding the constraint that "customers who request to change tariff either voluntarily, or through the actions of a retailer" in appendix E, SP AusNet did not

[101] ESCV, *EDPR 2006–10*, vol. 2, December 2008, pp. 24–27.

provide any evidence that this would inhibit its ability to incentivise customers to transfer off closed tariffs. The AER notes that SP AusNet did not provide any quantification of the magnitude of lower revenues that would be incurred through customers transferring from closed tariffs to lower revenue generating tariffs. Further, the AER notes that the constraint is consistent with constraints relating to the introduction of new tariffs or tariff components in the 2006–10 regulatory period. The AER also notes that the incentives and risks of the WAPC are widely recognised and were noted in the AER's Framework and approach paper and related stakeholder consultation.[102]

Based on this the AER considers that the revenue risks of customers voluntarily transferring from closed tariffs to lower revenue tariffs are not new and are consistent with the incentives and risks that a DNSP encounters when regulated by a WAPC. The AER therefore considers it appropriate to exclude customers who request to change their tariff either voluntarily or through the actions of a retailer from the calculation of reasonable estimates.

JEN proposed that q_{t-2}^{ij} in the numerator and denominator of the WAPC formula should be allowed to differ for capacity charges such as minimum booked/chargeable demand. JEN provided an example in which the movement of a customer to a different tariff with a different chargeable demand results in a revenue loss for the DNSP.[103] However, the AER does not consider that the intention of the WAPC is 'to compensate the DNSPs for the revenue loss caused by the reduction in chargeable demand as a consequence of customer's [sic] movement from one tariff to another' as JEN stated but rather is intended to incentivise DNSPs to structure their tariffs efficiently.[104] As stated above, the incentives and risks of the WAPC are widely recognised and were noted in the AER's Framework and approach paper and related stakeholder consultation.[105] The AER considers that allowing q_{t-2}^{ij} to vary as JEN suggests would distort the functioning of the weights in the WAPC formula. Further, the WAPC and side constraint provide the Victorian DNSPs with flexibility to restructure their tariffs. The AER therefore considers that JEN's proposal regarding q_{t-2}^{ij} in the WAPC for tariff reassignments involving capacity charges is not required.

AER conclusions

Appendix E of this final decision provides the principles on how new tariffs or tariff components are to be incorporated into the WAPC formula and side constraints.

4.4.1.8 Rounding

Victorian DNSP revised regulatory proposals

The AER has considered SP AusNet's and United Energy's revised regulatory proposals. The AER agrees with SP AusNet that using actual, as opposed to rounded, input figures poses no demonstrable administrative costs. This also addresses United Energy's concern that the output numbers may be biased one way or the other.

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102 AER, *Framework and approach*, p. 71.

103 JEN, *Response to AER information request on WAPC and side constraint of 31 August 2010*, Attachment 3, 15 September 2010, pp. 4–5.

104 ibid., p. 5.

105 AER, *Framework and approach*, p. 71.

The AER has therefore removed the requirement to round the percentage factors for the WAPC and side constraint formulae.

AER conclusions

Section 4.5 of this final decision sets out how the relevant percentage factors to the WAPC and side constraint formulae are to be rounded.

4.4.2 Recovery of transmission tariffs

4.4.2.1 Transmission related payments

Victorian DNSP revised regulatory proposals

The AER does not consider appropriate CitiPower's, Powercor's and United Energy's proposal to recover transmission related payments through additional parameters in the WAPC and side constraint formulae. As discussed in the draft decision, the AER is constrained by the NER in amending the control mechanisms from those specified in the Framework and approach paper.[106] Most notably, clause 6.12.3(c) of the NER provides that the control mechanism must be as set out in the relevant framework and approach paper. Contrary to the assertions made by CitiPower and Powercor, the AER has no power to depart from what is set out in the Framework and approach paper.[107]

In the draft decision, the AER did not consider that transmission connection, inter-DNSP and avoided TUOS costs, among other things, could be recovered through clause 6.18.7 of the NER. In the draft decision the AER agreed with SP AusNet's and United Energy's interpretation that TUOS is defined under the NER so as to exclude transmission connection costs. The AER also considered that inter-DNSP and avoided TUOS costs were excluded. These matters are currently under consideration by the AEMC in the context of a proposed Rule change and the AER considers that it is not appropriate for it to make a decision regarding the recovery of transmission connection, inter-DNSP and avoided TUOS costs in a distribution determination while the Rule change process is underway. [108] The AEMC is also considering savings and transitional requirements in the rule change process.[109]

The AER therefore considers it appropriate to adopt the position stated in the draft decision. The AER has informed the Victorian DNSPs of this. The AER has also made a public submission to the rule change process supporting a rule change. The AER stated that given the timing of the rule change process, it anticipates that the AER's final decision for the 2011-15 Victorian electricity distribution determinations will be consistent with its draft decision in respect of the TUOS costs that can be recovered through clause 6.18.7 of the NER and that consequently Victorian distribution tariffs for 2011 will include only those TUOS costs that can be recovered through clause 6.18.7 of the NER.

Chapter 16 of this final decision considers JEN's, SP AusNet's and United Energy's proposal to recover transmission related payments through the pass through

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106 AER, *Draft decision*, p. 58.

107 Section 4.4.1.2 further discusses these constraints.

108 AEMC, *National electricity amendment (DNSP recovery of transmission-related charges) rule 2010*, Consultation paper, 2 September 2010.

109 ibid., p.9.

mechanism. Appendix L of this final decision considers the Victorian DNSPs' proposals that transmission related payments be included as an opex allowance.

Regarding JEN's comments concerning the MTR, the AER notes the MTR as set out in appendix F of the draft decision addresses the AER's constituent decision under clause 6.12.1(19) of the NER.

Appendix F of this final decision sets out the approach to the recovery of charges set out in clause 6.18.7 of the NER for the forthcoming regulatory control period.

Submissions

In relation to EnergyAustralia's submission, the AER notes that the potential deficiency in clause 6.18.7 of the NER was brought to the AER's attention in SP AusNet's and United Energy's initial regulatory proposals. Prior to this it appeared that clause 6.18.7 of the NER was the appropriate mechanism for the recovery of transmission related payments. This is probably due to the term TUOS having both a narrow meaning (use of the transmission system) and a more general meaning (transmission related payments) in the electricity industry.[110] Hence, the AER included transmission related payments (including TUOS) as part of the recovery mechanism under clause 6.18.7 of the NER in previous distribution determinations. For the above reasons, the AER cannot, contrary to EnergyAustralia's submission, adopt an approach consistent with that applied for the AER's NSW determination. The AER considers that the current rule change process is the appropriate mechanism to clarify the policy intent behind clause 6.18.7 of the NER.

AER conclusions

As discussed above, the AER does not consider it appropriate that transmission related payments are recovered via the WAPC and side constraint formulae or through the MPR_t mechanism.

Appendix F of this final decision sets out the approach to the recovery of charges set out in clauses 6.18.7 of the NER for the forthcoming regulatory control period.

4.4.2.2 Premium feed in tariffs (PFIT)

Victorian DNSP revised regulatory proposals

In the draft decision the AER noted the Victorian DNSPs' proposals for mechanisms to recover PFIT payments. Specifically, CitiPower, Powercor and JEN proposed that PFIT payments be recovered through a mechanism similar to the 'G component' of the maximum transmission revenue (MTR) mechanism of clause 3.3 of the 2006 EDPR. SP AusNet proposed that PFIT payments be recovered as a pass through while United Energy proposed the addition of a factor to the WAPC formula.[111] The draft decision detailed the reasons for not accepting the Victorian DNSPs' proposals regarding the recovery of PFIT payments.[112]

The AER notes that on 7 October 2009, ETSA Utilities made a request to the AEMC to make a Rule change regarding the way in which DNSPs may recover payments

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110 IPART, *NSW electricity distribution pricing 2004/05 to 2008/09*, Final report, June 2004, p. 141.
111 AER, *Draft decision*, p. 52.
112 ibid., pp. 62–64.

they make under feed-in tariff schemes and climate change funds. The Rule Change Request included proposed amendments to chapter 6 of the NER.[113] The draft rule was subsequently published on 8 April 2010[114] prior to the AER's draft decision for Victoria and the final rule was published on 1 July 2010.

Given the expected timing for the rule change process, the AER considered in its draft decision that it would be appropriate to take into account the outcome of the rule change process in coming to its final decision regarding the recovery of PFIT payments by Victorian DNSPs in the forthcoming regulatory control period.

Clause 6.18.7A of the NER, which commenced on 1 July 2010, provides for the recovery of PFIT costs.[115] Appendix F of this final decision sets out the approach to the recovery of charges set out in clause 6.18.7A of the NER for the forthcoming regulatory control period. The maximum Jurisdictional scheme revenue (MJR) mechanism is similar in application to the MTR mechanism outlined in appendix F of the draft decision.

The AER considers that the inclusion of the MJR mechanism addresses the concerns raised by JEN and United Energy in their revised regulatory proposals.

Submissions

In relation to the Minister's submission, the AER notes the guidance provided by the AEMC regarding the recovery of administration costs relating to PFIT as opex under the NER. Appendix L of this final decision considers United Energy's proposed opex step change for administration costs relating to PFIT.

AER conclusions

Appendix F of this final decision sets out the approach to the recovery of charges set out in clause 6.18.7A of the NER for the forthcoming regulatory control period.

4.4.2.3 Maximum transmission revenue control correction factor Kzt

The AER has corrected the reference to TRa_{t-1} in the calculation of Kz_t to TRa_{t-2} as raised by CitiPower and Powercor.

AER conclusions

Appendix F of this final decision sets out the approach to the recovery of charges set out in clauses 6.18.7 and 6.18.7A of the NER for the forthcoming regulatory control period.

4.4.3 Tariff class assignment procedures

4.4.3.1 Issues with notification of tariff assignment for customer connections

Victorian DNSP revised regulatory proposals

The AER considers reasonable the comments made by CitiPower, Powercor and JEN that customers have either implicitly or explicitly agreed to the tariff class to which

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113 AEMC, *National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010*, Final determination, 1 July 2010, p. 1.

114 www.aemc.gov.au

115 ibid.

they have been assigned when they voluntarily enter into a contract with a retailer or distributor as the case may be. The AER has amended clause 6 of appendix G of the draft decision to reflect the approach proposed by CitiPower, Powercor, JEN and SP AusNet in their revised regulatory proposals.

Clause 6.18.4(a)(4) of the NER requires that a DNSP's decision to *assign* and reassign a customer to another tariff class should be subject to a system for assessment and review. The AER has amended clause 7.a. of the procedures in appendix G to ensure consistency with clause 6.18.4(a)(4). This is discussed further in section 4.4.3.2.

The tariff class assignment procedures for NSW, QLD and SA require DNSPs to notify customers of tariff class assignments (in addition to reassignments). The AER will monitor this issue across the NEM in the first round of distribution determinations under the NER. This will inform the AER's future approach in the transition towards a nationally consistent framework.

AER conclusion

The AER has amended clause 6 of appendix G in this final decision. Under this clause the Victorian DNSPs are not required to notify customers of tariff class assignments in the forthcoming regulatory control period. Victorian DNSPs are required to notify customers of tariff class reassignments in the forthcoming regulatory control period.

4.4.3.2 Dispute resolution through EWOV

Victorian DNSP revised regulatory proposals

Regarding CitiPower's, Powercor's, JEN's and SP AusNet's revised regulatory proposals, the AER notes that under the 2006 EDPR tariff reassignment disputes are referred to the ESCV. Clause 7 of appendix G of the draft decision sets out the dispute resolution options available for tariff *class* assignment and reassignment disputes (tariff class disputes). In the first instance a tariff class dispute is to be resolved through the Victorian DNSP's internal review system. If the tariff class dispute is not resolved, the matter may be escalated to EWOV then the AER.

In general, each customer is charged a tariff or tariffs and each tariff may contain a number of individual components. Each tariff belongs to a larger grouping known as a tariff class. Under clause 6.18.4(a) of the NER the AER considers that tariff *class* reassignments must meet significantly higher thresholds than tariff reassignments because the former entails a significant change in the customer's characteristics (this is not necessarily the case when a customer is reassigned to a different tariff within the same tariff class). The AER therefore does not consider that the tariff reassignment dispute resolution procedures in the 2006 EDPR can be automatically adopted for tariff class assignment and reassignment disputes.

In addition clause 7.a. of appendix G of the draft decision requires that tariff assignment and reassignment disputes are reviewed under the DNSP's internal review system as a first step.

The AER considers that the inclusion of EWOV in clause 7.b. of the tariff class assignment and reassignment procedures is consistent with current arrangements regarding the EWOV's role in tariff reassignment disputes and provides incentives to the Victorian DNSPs to adopt best practices and procedures to:

- assign or reassign customers to the appropriate tariff class
- ensure that appropriate outcomes are reached through the DNSP's internal review systems.

The AER considers that the costs associated with tariff class assignment or reassignment dispute resolution through EWOV to be avoidable costs and not a step change in the Victorian DNSPs' opex.

The AER notes that the escalation of frivolous objections to EWOV can be minimised through appropriate tariff class assignment procedures and effective internal review systems implemented by DNSPs. The AER also notes clause 6.3(a) of the EWOV charter which states that EWOV has the discretionary power to decline to investigate a complaint if the complaint is frivolous, vexatious or not made in good faith in the opinion of the Ombudsman.[116]

EWOV has informed the AER that it considers the wording of clause 7.b. in appendix G of the draft decision to be appropriate and that such disputes are currently within its jurisdiction and will continue to be.[117]

The AER therefore considers that the inclusion of EWOV in the tariff class assignment and reassignment procedures is appropriate.

Clause 10.1.2 of the Electricity Distribution Code (EDC) sets out procedures for complaints and dispute resolution applicable to the Victorian DNSPs as follows:

> When a distributor responds to a customer's complaint, the distributor must inform the customer:
>
> (a) that the customer has a right to raise the complaint to a higher level within the distributor's management structure; and
>
> (b) if, after raising the complaint to a higher level the customer is still not satisfied with the distributor's response, the customer has a right to refer the complaint to the Energy and Water Ombudsman (Victoria) Ltd. or other relevant external dispute resolution body. This information must be given in writing.[118]

The AER considers that clause 7 of appendix G of the draft decision does not conflict with the requirements of clause 10.1.2 of the EDC.[119] Clause 7 of appendix G of this final decision has been amended for further clarification.

The AER notes that United Energy's proposed opex relating to dispute resolution by EWOV relates to tariff reassignments and not tariff class reassignments.[120] JEN noted that its estimated costs for EWOV relate to tariff class assignments.[121] However for the reasons set out above, and noting in particular that tariff and tariff class

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116 EWOV, *Energy and water ombudsman charter*, 30 May 2006, p. 7.
117 EWOV, *AER email re DB issues*, email to AER, 29 September 2010.
118 ESCV, *Electricity distribution code*, Version 4, February 2010, p. 30.
119 Clause 22.1 of each Victorian DNSP's licence requires that the licensee apply with the EDC.
120 UED, *RE: TRIM: FW: Information request - opex step changes*, email to AER, 20 September 2010.
121 JEN, *RE: Tariff assignment step changes*, email to AER, 23 September 2010.

assignment and reassignment disputes are currently within the EWOV's jurisdiction and will continue to be, the AER does not consider these proposed costs to be opex step changes. This issue is also discussed in appendix L which considers opex step changes.

AER conclusion

The AER’s procedures for assigning and reassigning customers to tariff classes for the Victorian DNSPs are set out in appendix G of this final decision.

4.4.3.3 Customer notification for AMI time of use tariff reassignments

Victorian DNSP revised regulatory proposals

Clauses 14 and 15 of appendix G of the draft decision reiterate a requirement for Victorian DNSPs under clause 9.1.14 of the EDC. The AER has combined clauses 14 and 15 of appendix G of the draft decision because of their similarity. However the AER considers it inappropriate to amend this clause to specify notification of a customer's retailer as suggested by JEN because this would conflict with a jurisdictional code where the onus is on distributors to notify customers regarding TOU tariffs prior to the meter exchange.

AER conclusion

The AER’s procedures for assigning and reassigning customers to tariff classes for the Victorian DNSPs are set out in appendix G of this final decision.

4.4.3.4 Tariff reassignments

Victorian DNSP revised regulatory proposals

Regarding SP AusNet's comment on clause 1 of appendix G of the draft decision, the AER refers to clause 5 of appendix G of the draft decision which allows the Victorian DNSPs to reassign customers to a different tariff class if their load characteristics or connection characteristics (or both) have changed.

Regarding SP AusNet's comment on clause 5 of appendix G of the draft decision, the AER notes that clause 6.18.4(a) of the NER sets out the principles that the Victorian DNSPs must adhere to when assigning or reassigning customers to tariff classes. The AER considers that clause 5 of appendix G of the draft decision is consistent with clause 6.18.4(a) of the NER. SP AusNet stated that reassignment to the proposed Critical Peak Pricing could not be justified as resulting from a change in a customer's load and/or connection characteristics. The AER notes that SP AusNet may reassign customers to the Critical Peak Pricing tariffs (a tariff reassignment) even if there is no change in the customers' load and/or connection characteristics as long as the reassignment occurs within the same tariff class.

Regarding SP AusNet's example of the proposed Critical Peak Demand tariff, the AER considers that in the example provided by SP AusNet customers whose load characteristics or connection characteristics (or both) have not changed could be reassigned to the Critical Peak Demand tariff (tariff reassignment) provided this does not require a tariff *class* reassignment.

The AER therefore does not consider it necessary to amend clauses 1 and 5 of appendix G of the draft decision.

Submissions

Regarding Origin's submission, appendix G of the draft decision and this final decision sets out the procedures for tariff class assignments and reassignments consistent with clause 6.18.4 of the NER. The AER considers that these procedures encompass the situations outlined by Origin (such as an offer for premium services by a DNSP) where they relate to tariff class assignments and reassignments. For example a DNSP may offer premium services to customers then reassign them to the corresponding tariffs (a tariff reassignment) even if there is no change in the customers' load and/or connection characteristics as long as the reassignment occurs within the same tariff class.

AER conclusion

The AER's procedures for assigning and reassigning customers to tariff classes for the Victorian DNSPs are set out in appendix G of this final decision.

4.4.3.5 Tariff reassignment assumptions and price path calculations

Victorian DNSP revised regulatory proposals

The application of the net present value price path calculation in the PTRM is discussed in chapter 18 of this final decision.

Regarding appendix 4.2 of JEN's revised regulatory proposal, the AER notes that the WAPC and side constraint formulae for the forthcoming regulatory control period are specified in sections 4.5.1 and 4.5.2 below with discussion in sections 4.4.1.4 and 4.4.1.6 of this chapter.

AER conclusion

The WAPC and side constraint formulae for the provision of standard control services are specified in sections 4.5.1 and 4.5.2 of this chapter.

4.4.4 Other issues

4.4.4.1 Tariff setting and approval process

Submissions

Regarding the submissions from Origin, the CUAC and the EUAA, the AER notes that in July 2010 it requested that the Victorian DNSPs provide draft pricing proposals to the AER's Consumer Consultative Forum for Victoria to enable greater consultation with customer stakeholders in relation to the pricing proposal process.[122] United Energy and SP AusNet subsequently participated in this process.

The AER further notes, however, that the submission of such draft pricing proposals is at the discretion of each DNSP and are not a requirement under the NER.

[122] AER, *Electricity pricing proposal for 2011*, Letter to CitiPower and Powercor, 22 July 2010; AER, *Electricity pricing proposal for 2011*, Letter to JEN, 22 July 2010; AER, *Electricity pricing proposal for 2011*, Letter to SP AusNet, 22 July 2010; AER, *Electricity pricing proposal for 2011*, Letter to United Energy, 22 July 2010.

AER conclusion

The AER notes that clause 6.18 of the NER outlines the processes and timing for the assessment of pricing proposals.

4.5 AER conclusion

As part of their pricing proposals, the Victorian DNSPs must submit to the AER proposed tariffs and charging parameters which correspond to the price terms contained in the WAPC and side constraint equations set out below.

In accordance with clause 6.12.1(11) of the NER, the AER's WAPC formula is set out below. In accordance with clause 6.12.1 (13), compliance with the WAPC formula will be monitored consistent with the requirements in appendix E of this final decision. In accordance with clause 6.12.1 (17) and (19) of the NER, the procedures for assigning tariffs, and for reporting the recovery of the charges described in clause 6.18.7 of the NER are set out in appendices G and F respectively of this final decision. Appendix F also contains the procedures for reporting the recovery of charges described in clause 6.18.7A of the NER in accordance with clause 6.12.1(20) of the NER.

The AER's WAPC formula and side constraints are also set out in the final determination documents for CitiPower, Powercor, JEN, SP AusNet and United Energy.

4.5.1 Weighted average price cap

The WAPC formula to apply to the Victorian DNSPs for the forthcoming regulatory control period is:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\pm(passthrough_t)$$

where a DNSP has *n* distribution tariffs, which each have up to *m* distribution tariff components, and where:

regulatory year "t" is the regulatory year in respect of which the calculation is being made;

regulatory year "t-1" is the regulatory year immediately preceding regulatory year "*t*";

regulatory year "t-2" is the regulatory year immediately preceding regulatory year "*t-1*";

p_t^{ij} is the proposed distribution tariff for component *j* of distribution tariff *i* in regulatory year *t*;

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year *t-1* for component *j* of distribution tariff *i*;

q_{t-2}^{ij} is the quantity of component *j* of distribution tariff *i* that was delivered in regulatory year *t-2*;

CPI_t is calculated as follows:

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year *t*;
>
> **divided by**
>
> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year *t-1*;
>
> **minus one**.

X_t is the value of *X* for year *t* of the regulatory control period as determined by the AER in chapter 18 of this final decision;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*;

L_t is the licence fee pass through adjustment to be applied in regulatory year *t* in accordance with appendix E of this final decision; and

$passthrough_t$ represents approved pass through amounts with respect to regulatory year *t* as determined by the AER under clause 6.6 of the NER and chapter 16 and appendix E of this final decision.

4.5.2 Side constraints

The side constraints formula to apply to the Victorian DNSPs for the forthcoming regulatory control period is:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+L_t)\times(1+2\%)\pm(passthrough_t)$$

Where for each tariff class a DNSP has *n* distribution tariffs, which each have up to *m* distribution tariff components, and where:

regulatory year "t" is the regulatory year in respect of which the calculation is being made;

regulatory year "t-1" is the regulatory year immediately preceding regulatory year "*t*";

regulatory year "t-2" is the regulatory year immediately preceding regulatory year *"t-1"*;

p_t^{ij} is the proposed distribution tariff for component *j* of distribution tariff *i* in regulatory year *t* ;

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year *t-1* for component *j* of distribution tariff *i*;

q_{t-2}^{ij} is the quantity of component *j* of distribution tariff *i* that was delivered in regulatory year *t-2*;

CPI_t is defined as set out in section 4.5.1 of this final decision;

X_t is the value of *X* for year *t* of the regulatory control period as determined by the AER in chapter 18 of this final decision. If $X>0$, then *X* will be set equal to zero for the purposes of the side constraint formula;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*;

L_t is the licence fee pass through adjustment to be applied in regulatory year *t* in accordance with appendix E of this final decision; and

$passthrough_t$ represents approved pass through amounts with respect to regulatory year *t* as determined by the AER under clause 6.6 of the NER and chapter 16 and appendix E of this final decision.

4.5.3 Ring fencing

Ring fencing guidelines form an integral part of a regulatory regime. Clause 11.14.5(b)(3) of the NER states that ring fencing guidelines in force in a participating jurisdiction immediately before the AER's assumption of regulatory responsibility (transitional guidelines) continue in force for that jurisdiction. The ESCV's ring fencing guidelines are therefore applicable transitional guidelines for Victoria.[123] Consistent with clause 11.14.5(c) of the NER these transitional guidelines will be regarded as the AER's guidelines and any reference to the jurisdictional regulator will be considered a reference to the AER until amended, revoked or otherwise replaced by the AER.

The transitional guidelines set out specific requirements in regard to:

- non-discriminatory conduct by DNSPs
- provision of information by DNSPs to retail businesses
- separation of organisational units
- branding, marketing and customer communications

[123] ESCV, *Electricity industry guideline no.17: Electricity ring-fencing Issue 1*, October 2004.

- outsourcing.

The ESCV did not include any specific compliance measures in the electricity ring fencing guideline. Instead, it relied on its general approach to compliance, including investigating complaints and conducting periodic compliance audits, to assess compliance with the guideline.[124] The AER will continue with this approach in the forthcoming regulatory control period.

To the extent that the ESCV's reporting guidelines do not cover additional matters addressed in this final decision, such as the incentive schemes discussed in chapters 14, 15 and 17, chapter 21 of this final decision sets out monitoring and compliance requirements.

[124] ESCV, *Final decision: Ring-fencing in the Victorian electricity industry*, October 2004, p. 24.

5 Growth forecasts

This chapter outlines the AER's final decision on the Victorian DNSPs' maximum demand, energy sales and customer numbers forecasts (collectively, 'growth forecasts') for the forthcoming regulatory control period.

Maximum demand (measured in MW or MVa) is the highest level of network capacity required to supply electricity at a single point in time and is a key driver of load driven capital expenditure (capex) requirements.

Energy sales forecasts (measured in GWh) are used to determine the expected revenue of the DNSP and are a key input to the post-tax revenue model (PTRM) where X factors are set to equate building block requirements to expected revenues under the weighted average price cap (WAPC) form of control mechanism.

Customer number forecasts are similarly important in determining expected revenues and are also a driver of connection related capex.

This chapter details the AER's assessment of the Victorian DNSPs' revised regulatory proposals, including:

- summarising the draft decision on growth forecasts
- providing a general overview of the revised regulatory proposals and stakeholder submissions on the growth forecasts
- comparing of the revised regulatory proposal growth forecasts against historical data, other forecasts and the Victorian DNSPs' previous forecasts
- updating the methodological assessment in the draft decision for new information submitted by the Victorian DNSPs and their consultants
- detailing the AER's assessment of the major inputs into the growth forecasts, and the post-model policy adjustments
- detailing the AER's assessment of the Victorian DNSPs' revised spatial maximum demand forecasts, including assessment of selected zone substations (ZSS) and the DNSPs' approaches to reconciliation between bottom-up and top-down forecasts
- analysing the arguments surrounding the likely impact of time of use tariffs on growth forecasts
- outlines the AER's response to CitiPower's and Powercor's comments on the National Electricity Rules (NER) requirements relating to growth forecasts.

5.1 Regulatory requirements

Clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER require the AER to assess whether a DNSP's forecast of operating expenditure (opex) and capex reasonably reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex/capex objectives. The opex and capex objectives are set out in clauses 6.5.6(a) and 6.5.7(a) of the NER, respectively. Clauses 6.5.7(a)(1) and 6.5.6(a)(1) of the NER state that a building block proposal must contain forecasts of total opex and capex respectively that the DNSP considers are required, inter alia, to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

Clause 6.12.1(10) of the NER requires the AER to make a decision on appropriate amounts, values or inputs. These include forecasts of energy consumption and customer numbers which are inputs to the AER's calculation of expected revenues in the PTRM.

5.2 AER draft decision

The draft decision rejected each of the Victorian DNSPs' proposed maximum demand, energy and customer number forecasts for the forthcoming regulatory control period. In reaching its conclusions, the AER was informed by the analysis and recommendations of its consultant, ACIL Tasman, which was generally requested to review the reasonableness of the forecasts. The following sections briefly summarise the AER's reasons for rejecting the proposed forecasts, and provide the replacement forecasts approved in the draft decision.

5.2.1 Maximum demand

The AER and ACIL Tasman found certain flaws in the methods applied by the Victorian DNSPs in generating their maximum demand forecasts, in particular in the lack of reconciliation between independently generated top-down (network level) forecasts and network planner produced bottom up (ZSS level) forecasts.

As a result of the lack of reconciliation, the AER considered that the DNSPs' forecasts did not properly account for economic growth and the impact of government policies. The AER also noted the lack of transparency and repeatability in the methods applied by most of the DNSPs.

The AER also disagreed with the DNSPs' assumptions about the impacts of particular government policies on maximum demand, including standby power, insulation subsidy and time of use (TOU) tariffs on the network level forecasts.

For the draft decision, the AER used data on the historical diversity between network and ZSS level maximum demands for each DNSP to properly reconcile the bottom up forecasts to the top down forecasts, which were themselves adjusted to reflect a more realistic expectation of policy impacts, as recommended by ACIL Tasman. The reconciliation was used to calculate a total required reduction in each DNSPs' summed ZSS maximum demand forecast, which was then allocated among the forecasts for a selected number of individual ZSS for the purposes of informing the AER's assessment of reinforcement capex.[1]

The AER considered the Victorian economic growth forecasts, population growth forecasts and Carbon Pollution Reduction Scheme (CPRS) assumptions underpinning

[1] The draft decision zone substation forecasts were provided in AER, *Draft decision*, June 2010, pp. 134–142.

the demand forecasts needed to be updated within the DNSPs' revised regulatory proposal forecasts. Table 5.1 sets out the draft decision approved maximum demand forecasts, being the sum of the approved ZSS forecasts.

Table 5.1 Draft decision conclusions on maximum demand forecasts—sum of non-coincident ZSSs (MW)

	2011	2012	2013	2014	2015
CitiPower	1 465	1 509	1 573	1 603	1 627
Powercor[(a)]	2 327	2 437	2 569	2 669	2 747
Jemena Electricity Networks (JEN)	1 067	1 096	1 134	1 168	1 184
SP AusNet	1 858	1 928	2 032	2 125	2 212
United Energy	2 266	2 352	2 406	2 509	2 558

(a) Sum of coincident ZSSs.

5.2.2 Energy consumption

Similar to the DNSPs' maximum demand forecasts, the AER considered that the DNSPs' proposed energy consumption forecasts reflected inappropriate assumptions regarding a number of government policies. In particular, the AER removed the impact of standby power, insulation subsidy and time of use pricing from the DNSPs' proposed energy forecasts.

The AER and ACIL Tasman also disagreed with the DNSPs' assumed impact of the Minimum Energy Performance (MEPs) for Lighting on energy consumption, and constrained the impact to an Australian Government estimate within the draft decision approved forecasts.[2]

The draft decision also stated the AER's expectation that the DNSPs' revised regulatory proposal energy forecasts would incorporate updated impacts of gross state product (GSP), revised population growth forecasts and revised assumptions about the CPRS following recent policy developments.[3]

Table 5.2 sets out the draft decision energy consumption figures for each DNSP.

2 AER, *Draft decision*, pp. 111–115.
3 AER, *Draft decision*, p. 156.

Table 5.2 Draft decision conclusions on energy consumption (GWh)

	2011	2012	2013	2014	2015
CitiPower	6 246	6 430	6 544	6 595	6 678
Powercor	11 163	11 463	11 764	11 994	12 151
JEN	4 439	4 544	4 647	4 725	4 783
SP AusNet	8 187	8 345	8 543	8 796	9 039
United Energy	8 193	8 444	8 710	8 921	9 072

5.2.3 Customer numbers

The draft decision noted that the DNSPs' customer number forecasts were largely consistent with growth trends over the current regulatory control period. The draft decision stated the AER's expectation that the DNSPs would revise their proposed customer number forecasts within their revised regulatory proposals for updated GSP and population growth inputs.[4] Table 5.3 sets out the draft decision customer number forecasts for each DNSP.

Table 5.3 Draft decision conclusions on customer number forecasts

	2011	2012	2013	2014	2015
CitiPower	316 243	321 189	324 686	328 584	334 914
Powercor	715 541	727 610	739 714	752 719	766 214
JEN	308 296	313 257	317 334	320 907	325 049
SP AusNet	634 191	644 900	654 309	663 159	672 912
United Energy	630 196	634 300	637 565	641 377	646 461

5.3 Victorian DNSP revised regulatory proposals

In their revised regulatory proposals, the Victorian DNSPs:

- did not accept the AER's adjustments to their forecasts of energy consumption and maximum demand
- engaged NIEIR to produce revised energy consumption and top down maximum demand forecasts, using updated assumptions for economic growth, population growth forecasts and for the CPRS, consistent with the AER's draft decision recommendations[5]

4 AER, *Draft decision*, p. 99.

5 NIEIR, *Electricity sales and customer number projections for the CitiPower region to 2019 — Class and network tariff groups*, June 2010; NIEIR, *Maximum summer demand forecasts for*

- carried out different approaches to reconcile each of their own spatial maximum demand forecasts to NIEIR's revised maximum demand forecasts, which was also in direct response to the AER's criticisms of their methodologies

- adopted NIEIR's revised customer number forecasts that reflect updated population growth forecasts, consistent with the AER's draft decision recommendations

- rejected the AER’s draft decision on the impact on the growth forecasts of Government policies on MEPs lighting, standby power, insulation target and AMI

- adopted NIEIR’s revised policy impacts on electricity sales and maximum demand forecasts (aside from JEN and SP AusNet, both of which applied different assumptions regarding the impact of the AMI rollout)

CitiPower and Powercor also engaged Frontier Economics (Frontier) to provide expert reports in support of NIEIR’s policy adjustments in updating their respective energy sales forecasts.[6]

JEN adopted NIEIR’s revised energy consumption forecast, but amended it to incorporate Frontier Economics' estimate of the impact of the AMI rollout on electricity sales.[7]

Similarly, SP AusNet requested that NIEIR remove any assumed impact of the AMI rollout from its revised energy consumption and maximum demand forecasts. Its revised energy and maximum demand forecasts did not include any assumed impact of TOU tariffs for 2011–15, although did include the impact of customers that have moved to TOU tariffs in 2010.

Tables 5.4 to 5.8 summarise the Victorian DNSPs' revised regulatory proposal growth forecasts.

CitiPower to 2020, June 2010; NIEIR, *Electricity sales and customer number projections for the Powercor Australia region to 2019 —Class and network tariff groups*, June 2010; NIEIR, *Maximum summer demand forecasts for Powercor Australia to 2020*, June 2010; NIEIR, *Electricity sales and customer number forecasts to 2019 for the JEN electricity region*, June 2010; NIEIR, *Maximum summer demand forecasts for Jemena Electricity Networks to 2020*, June 2010; NIEIR, *Electricity sales and customer number forecasts for the SP AusNet distribution region to 2019 (class and network tariff)*, June 2010; NIEIR, *Maximum demand forecasts for SP AusNet terminal stations to 2020—Summer and winter and coincident and non-coincident*, June 2010; NIEIR, *Electricity sales and customer number forecasts for the United Energy region to 2019 (class and network tariff)*, June 2010; NIEIR, *Maximum summer demand forecasts for United Energy to 2020*, June 2010. The AER notes that NIEIR prepared individual reports for each DNSP's maximum demand and energy and customer number forecasts, however the areas discussing methodology, impact of economic growth and Government policies are largely identical in each DNSP's reports. Accordingly, when referring to the NIEIR reports, this final decision will refer to the reports prepared for JEN, however the reference can be inferred to be identical for each DNSP, unless stated otherwise.

6 Frontier Economics, *Review of policy adjustments–a report prepared for CitiPower*, July 2010; Frontier Economics, *Review of policy adjustments–a report prepared for Powercor*, July 2010; Frontier Economics, *Review of ACIL Tasman recommendations: A report for CitiPower*, July 2010.

7 Jemena Electricity Networks (Vic) Ltd, *Revised Regulatory Proposal 2011–15*, 20 July 2010, p. 37.

Table 5.4 Summary CitiPower revised regulatory proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW)[a]	1515	1557	1598	1639	1682	2.9
Energy (GWh)	6 177	6 210	6 182	6 148	6 177	0.2
Customer numbers	316 818	322 742	327 190	331 100	337 050	1.7

(a) Summation of demand at non-coincident ZSS and 22kV terminal station points of supply, based on a 50 per cent PoE forecast.

Source: CitiPower, *Revised Regulatory Proposal*, p. 120; CitiPower revised RIN template 6.3, sum table 21.

Table 5.5 Summary of Powercor proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW)[a]	2 481	2 557	2 652	2 747	2 848	3.2
Energy (GWh)	10 718	10 763	10 712	10 666	10 691	0.2
Customer numbers	717 745	731 603	745 570	759 343	772 544	1.9

(a) Summation of demand at non-coincident ZSS and 22kV terminal station points of supply, based on a 50 per cent PoE forecast.

Source: Powercor, *Revised Regulatory Proposal*, p. 112; CitiPower revised RIN template 6.3, sum table 21.

Table 5.6 Summary of JEN proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW)[a]	1 099	1 130	1 162	1 192	1 213	2.1
Energy (GWh)	4 331	4 312	4 254	4 200	4181	–0.8
Customer numbers[b]	313 164	318 616	323 161	327 188	331 669	1.5

(a) Summation of demand at non-coincident ZSS and 22kV terminal station points of supply, based on a 50 per cent PoE forecast.

(b) Customer numbers are as at year end, while numbers in table 5.25 are average customer numbers.

Source: JEN, *Revised Regulatory Proposal*, pp. 58–59; JEN revised RIN template 6.3, sum table 21.

Table 5.7 Summary of SP AusNet proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW) [a]	1 876	1 960	2 048	2 133	2 221	5.1
Energy (GWh)	7 969	8 016	8 002	8 007	8 051	0.6
Customer numbers	633 847	646 034	657 240	667 352	677 204	1.7

(a) Summation of demand at non-coincident ZSS and 22kV terminal station points of supply, based on a 50 per cent PoE forecast.

Source: SP AusNet, *Revised Regulatory Proposal*, pp. 67–68; SP AusNet revised RIN template 6.3, sum table 21.

Table 5.8 Summary of United Energy proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW) [a]	2 359	2 424	2 495	2 576	2 591	2.2
Energy (GWh)	7 929	7 936	7 868	7 801	7 800	–0.2
Customer numbers [b]	630 635	636 421	641 506	646 067	650 752	0.8

(a) Summation of demand at non-coincident ZSS and 22kV terminal station points of supply, based on a 10 per cent PoE forecast.

(b) Customer numbers are as at year end, while numbers in table 5.25 are average customer numbers.

Source: United Energy, *Revised Regulatory Proposal*, p. 273; United Energy revised RIN template 6.3, sum table 21.

5.4 Submissions

The AER received submissions from the following parties:

- Consumer Utilities Advocacy Centre (CUAC)
- EnergyAustralia
- Energy Users Association of Australia (EUAA)
- Energy Users Coalition of Victoria (EUCV)
- Grid Australia
- Origin Energy (Origin)
- Total Environment Centre (TEC)

- TRUenergy
- Visy Industries Australia (Visy)
- Victorian Employers' Chamber of Commerce and Industry (VECCI).

Various submissions considered that the Victorian DNSPs’ forecasts could not be relied upon to set efficient revenue levels in the forthcoming regulatory control period, noting the historical trend of under-forecasting energy consumption.[8] Many submissions also endorsed the AER’s draft decision approach to reviewing the DNSPs' growth forecasts.[9]

Some stakeholders also suggested that the Victorian DNSPs' energy forecasts should be adjusted in line with forecasts within AEMO’s Statement of Opportunities (SOO) and 2010 Annual Planning Report (VAPR).[10]

EnergyAustralia expressed concern regarding the AER’s use of VENCorp’s 2009 state-wide forecasts to form its view on the DNSPs’ forecast growth. It was also noted VENCorp’s forecasts were developed for different purposes to those of the DNSPs.[11]

Grid Australia considered that the AER had not given sufficient weight to forecast demand growth in other jurisdictions outside Victoria, or the increased penetration of air conditioners in Victoria.[12]

Origin also raised concerns regarding the DNSPs' assumed impact of TOU tariffs on demand and energy forecasts.[13] The Victorian Employers' Chamber of Commerce and Industry (VECCI) raised issues around the ability of businesses to respond to TOU tariffs, and transferring benefits of the AMI rollout to customers.[14]

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8 Consumer Utilities Advocacy Centre (CUAC), *Submission in response to the AER draft electricity distribution determination for Victoria and the distribution businesses revised revenue proposals*,19 August 2010; Energy Users Coalition of Victoria (EUCV), Submission *to the AER - 2010 AER review of Victorian Electricity DBs, EUCV response to AER Draft Decision*, August 2010; Energy Users Association of Australia (EUAA), *Submission to the AER - AER Draft Determination on Victorian electricity distribution prices for the period 2011-2015 and distributors revised proposals*, 19 August 2010; TRU Energy, *Submission to the AER - Victorian electricity distribution network service providers distribution determination 2011-2015: Draft decision*, 16 August 2010, pp. 3–4; Total Environment Centre, *Submission to the AER on Draft decision Victorian electricity distribution network service providers 2011–2015*, 24 August 2010, p. 2.

9 Origin, *Submission to the AER – Victorian Electricity Distribution Draft Determination and Revised Proposals*, 19 August 2010, p. 1; CUAC, *Submission to the AER*, August 2010, p. 2; EUAA, *Submission to the AER*, August 2010, pp. 18–19; TRUenergy, *Submission to the AER*, August 2010, p. 1; Total Environment Centre, *Submission to the AER*, August 2010, p. 2.

10 TRUenergy, *Submission to the AER*, August 2010, pp. 3–4; EUCV, *Submission to the AER*, August 2010, pp. 59–62.

11 EnergyAustralia, *Submission to the AER – EnergyAustralia submission on AER draft regulatory determination for Victorian distributors*, 19 August 2010, p. 17.

12 Grid Australia, *Submission to the AER – Victorian Electricity Distribution Draft Decision 2011–15*, 19 August 2010, pp. 4–5.

13 Origin, *Submission to the AER*, August 2010, pp. 1–6.

14 The Victorian Employers' Chamber of Commerce and Industry (VECCI), *Submission to the AER – AER draft decision on Distribution Network Tariffs for 2011–15*, 26 August 2010.

Visy noted JEN's forecasts for a fall in consumption may be at odds with Visy's projection of a relatively flat demand growth over the forthcoming regulatory control period.[15]

JEN provided a further submission in late September which responded to a number of issues raised in stakeholder submissions, including Origin's comments on JEN's 2006 maximum demand forecasts as compared to actual maximum demand.[16]

5.5 Consultant review

The AER re-engaged ACIL Tasman to provide expert advice and inform its review of the Victorian DNSPs' revised growth forecasts. The areas where ACIL Tasman concentrated its assessment included:

- for maximum demand:
  - the reasonableness of the updated economic growth and CPRS inputs into the revised forecasts
  - the process of reconciliation of top down and bottom up forecasts applied by each DNSP
  - the reasonableness of the revised spatial maximum demand forecasts, including a close review of a sample of ZSS for each DNSP, as selected by the AER
- for energy and customer numbers:
  - the reasonableness of the revised economic growth, CPRS and population forecast inputs into the revised forecasts
  - the reasonableness of the DNSPs' and NIEIR's assumptions on the impact of various Government policies, including the AMI rollout
  - consistency of the forecasts with historical data.

In the report it submitted to the AER prior to the draft decision, ACIL Tasman noted that it was provided with limited information in relation to NIEIR's core forecasting models, which made it difficult to draw concrete conclusions about the reasonableness of the underlying forecasts.[17]

However, ACIL Tasman concluded that, based on the information available, the methodologies applied by NIEIR exhibited features of good forecasting practice and

15 Visy, *Submission to the AER – AER draft determination on regulatory proposal submitted by Jemena Electricity Networks (Vic) Ltd (JEN)*, 19 August 2010, p. 2.

16 JEN, *JEN 2011–15 regulatory proposal: Response to stakeholder submissions*, 24 September 2010, Attachment 3.

17 ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of maximum demand forecasts, Report prepared for the AER*, 19 April 2010, p. 12.

were likely to be generally sound and capable of producing reasonable forecasts, subject to the relevant economic, population and CPRS inputs being updated.[18]

In its review of the DNSPs' revised forecasts, ACIL Tasman found that NIEIR's updated economic growth, population growth and CPRS assumptions were reasonable and addressed the issues raised in the AER's draft decision.[19]

With regard to customer numbers forecasts, ACIL Tasman considered it was not provided with sufficient evidence to reach a conclusion on the reasonableness of the methodology applied by NIEIR. However, ACIL Tasman noted that the forecasts are reasonably consistent with historic trends in customer number growth, which suggested that the forecasts were not unreasonable.[20]

ACIL Tasman also considered that, other than the one watt standby policy and NIEIR's assumed AMI impact, NIEIR's revised post model adjustments for Government policy measures were reasonable. ACIL Tasman concluded the assumed impacts of AMI adopted by JEN and calculated by SP AusNet were not unreasonable, however noted the high degree of uncertainty surrounding the implementation of time of use tariffs in Victoria.[21] It also concluded that NIEIR's estimated impact of the VEET scheme on Victorian electricity consumption may be too low.[22]

Further details on ACIL Tasman's advice are provided in the following sections. ACIL Tasman's reports have been published by the AER along with this final decision.

5.6 Issues and AER considerations

5.6.1 General trends and historic comparisons

5.6.1.1 AER draft decision

The draft decision compared the Victorian DNSPs' maximum demand, energy and customer number forecasts for 2011–15 with recent growth trends, previous regulatory forecasts prepared by the DNSPs and the ESCV, and forecasts prepared by VENCorp (now AEMO) for its 2009 VAPR.[23]

The maximum demand comparisons showed that the Victorian DNSPs were collectively forecasting much stronger growth than VENCorp, such that by 2014 the DNSPs' forecasts were higher than VENCorp's forecast, despite the latter including transmission connected customer forecasts.[24]

The draft decision also demonstrated that the Victorian DNSPs' forecasts in their 2006 regulatory proposals to the ESCV were above actual maximum demands reported over 2006–08. This was contrary to expectations given the unseasonably hot summers

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18 ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of revised growth forecasts–draft report, Report prepared for the AER*, 14 October 2010, pp. 3–4.
19 ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 11–20.
20 ibid., p. 10.
21 ibid., pp. 46–50.
22 ibid., pp. 38–39.
23 AER, *Draft decision*, June 2010, pp. 79–85.
24 ibid., p. 80.

in these years, however the draft decision noted that lower than forecast demands could have been the result of economic slowdown during the global financial crisis.[25]

The energy consumption comparisons demonstrated that the Victorian DNSPs' forecasts for the forthcoming regulatory control period depicted a significant departure from recent history, driven by customer responses to high electricity prices, energy efficiency policies and low economic growth.[26]

The draft decision demonstrated the difference in growth rates between VENCorp's 2009 VAPR energy forecast (an average annual increase of 0.9 per cent over 2011–15) and the DNSPs' forecasts (–0.7 per cent per year over the same period).[27] The draft decision stated that these comparisons were consistent with the incentives of the weighted average price cap, and suggested that the proposed forecasts were likely understating forecast energy consumption.[28]

The customer number comparisons demonstrated that the Victorian DNSPs were forecasting similar growth as seen in recent years, with the exception of JEN, which anticipated stronger customer number growth than in the current regulatory control period. The draft decision also showed that there was no systematic under or over forecasting of customer numbers in the Victorian DNSPs' 2006 customer number forecasts to the ESCV.[29]

5.6.1.2 Victorian DNSP revised regulatory proposals

NIEIR

The NIEIR reports submitted by each DNSP as part of their revised regulatory proposals provide some comments on the AER's comparison of the VENCorp 2009 VAPR with the Victorian DNSPs' energy forecasts.[30] NIEIR stated that the energy forecast comparison is not valid because:

- the VENCorp forecast was prepared in April 2009, and based on economic profiles of 3 per cent growth per annum over 2011–15, as compared to NIEIR's economic growth forecast of 1 per cent over the same period
- the VENCorp forecast includes direct transmission customers, who are large customers and have a big impact on the forecast
- the policy assumptions differed between VENCorp and NIEIR, in particular around the impact of AMI. VENCorp excluded any commercial policy impacts.[31]

JEN's and United Energy's revised regulatory proposals restated NIEIR's comments on the VENCorp comparison.[32]

25 ibid., pp. 80–81.
26 ibid., p. 81.
27 ibid., p. 82.
28 ibid., pp. 84–85.
29 AER, *Draft decision*, June 2010, pp. 83–84.
30 For example see NIEIR, *Electricity sales and customer number forecasts for the JEN electricity region*, June 2010, p. 8.
31 ibid.

CitiPower and Powercor

CitiPower's and Powercor's revised regulatory proposals stated that VENCorp's 2009 VAPR energy forecasts are now significantly out of date and do not reflect recent economic conditions. CitiPower and Powercor also noted that methodological issues would arise in trying to split VENCorp's state wide forecasts across the Victorian DNSPs.[33]

CitiPower and Powercor pointed out that in making comparisons between 2006–10 forecasts and actual maximum demand, the AER relied on information within the ESCV's 2006 EDPR which was incorrectly labelled. Rather than being non-coincident ZSS level forecasts as cited by the ESCV, CitiPower and Powercor submitted that the forecasts were the sum of feeder level maximum demand forecasts, to which the AER compared actual unadjusted maximum demand. CitiPower and Powercor submitted that the sum of the feeder level maximum demands will always be greater than the sum of the ZSS maximum demands, as the feeders do not always peak at the same time.[34]

CitiPower and Powercor submitted that their actual 2006–08 ZSS maximum demand was on average, 97.6 per cent of their regulatory forecast. CitiPower and Powercor also submitted that their forecasts of 2010 maximum demand were very close to actual recorded maximum demands, being 95 and 103 per cent of the forecasts respectively.[35]

United Energy

United Energy's revised regulatory proposal discussed the general uncertainty associated with forecasting customer numbers, energy and maximum demand, and the risk that incorrect forecasting poses to its business.[36] United Energy provided diagrams comparing its own previous regulatory forecasts, forecasts approved by the Office of the Regulator General, the ESCV and the AER's draft decision, and the outcomes to date as reported by United Energy as part of its regulatory information notices.[37]

United Energy submitted that its actual customer numbers have fluctuated between –7 and 3 per cent of the approved forecasts over 2001–10, due to unexpected migration and economic growth in Victoria. United Energy submitted that its actual energy consumption has been between –4.5 and 2.8 per cent of NIEIR's previous forecasts, which it considers demonstrates the strength of NIEIR's model.[38]

For maximum demand, United Energy's revised regulatory proposal outlined actual and NIEIR forecast data, presented on a number of different bases, including

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32 JEN, *Revised regulatory proposal*, July 2010, pp. 57–58; United Energy, *Revised regulatory proposal*, July 2010, p. 271–272.

33 CitiPower, *Revised regulatory proposal*, July 2010, p. 108; Powercor, *Revised regulatory proposal*, July 2010, p. 101.

34 CitiPower, *Revised regulatory proposal*, July 2010, p. 111; Powercor, *Revised regulatory proposal*, July 2010, pp. 103–104.

35 CitiPower, *Revised regulatory proposal*, July 2010, p. 112; Powercor, *Revised regulatory proposal*, July 2010, pp. 103–105.

36 United Energy, *Revised regulatory proposal*, July 2010, pp. 242–247.

37 ibid.

38 ibid., pp. 243–244.

coincident network peak, feeder peak and ZSS peak.[39] It stated that NIEIR's modelling output requires considerable 'interpretation' to derive peak demand forecasts, and that top down maximum demand forecasts are of little use in developing coherent business plans.

United Energy suggested that the AER's and ACIL Tasman's review of NIEIR's maximum demand forecasts was of little value.[40] United Energy suggested that the AER review its latest 2009 Distribution Planning System Report, which shows that the majority of United Energy's ZSS are in need of system reinforcement, and that maximum demand is only relevant for critically loaded network assets, where peaks often occur at different times over the summer period.[41]

United Energy compared the AER's approach to reviewing and adjusting growth forecasts in the draft decision to the approaches applied by the Office of the Regulator General (ORG) and the ESCV in the current and previous regulatory control periods, as well as the approach adopted by the AER in reviewing the NSW and Queensland DNSPs' growth forecasts for their respective current regulatory control periods.[42] United Energy stated:

> In comparison, the views and opinions expressed by the AER in the Draft Decision suggest a bias at odds with the regulatory precedent established by the ORG and the ESC.[43]

United Energy stated that the AER must only not accept United Energy's forecasts if those forecasts are not a 'realistic expectation,' and submitted that its forecasts are realistic.[44]

5.6.1.3 Submissions

A number of stakeholders compared the Victorian DNSPs' growth forecasts to other key forecasts, and commented on the general growth trends exhibited in the forecasts.

Grid Australia submitted that demand growth in Victoria is comparable to that in other jurisdictions, and that in its draft decision, the AER had not given sufficient weight to peak demand growth and air conditioning penetration as compared to its distribution determinations for other jurisdictions.[45]

TRUenergy submitted that the Victorian DNSPs' energy forecasts should be in line with AEMO's energy forecasts, noting that AEMO incorporated the same critical policy variables as NIEIR's forecasts.[46]

VISY submitted that JEN's energy forecast does not reflect its own relatively stable, flat load at two of its largest plants, which is not expected to change over 2011–15.[47]

[39] ibid. p. 245, figure 13.4.
[40] ibid., p. 245.
[41] ibid., p. 246.
[42] ibid., p. 247.
[43] ibid., p. 247.
[44] ibid., p. 247.
[45] Grid Australia, Submission to the AER, August 2010, pp. 4–5.
[46] TRUenergy, Submission to the AER, August 2010, pp. 3–4.
[47] VISY, Submission to the AER, August 2010, pp. 1–2.

EnergyAustralia stated that the AER had placed considerable weight on the variance between the DNSPs' and VENCorp's forecasts in the draft decision. EnergyAustralia cautioned the AER against:

> …any approach which dogmatically substitutes a business's own forecasts with other forecasts which have been developed for different purposes.[48]

It suggested that the AER should undertake the same rigorous analysis of the VENCorp forecasts as that applied to the Victorian DNSPs' forecasts, and noted that the VENCorp 2010 VAPR energy forecasts are lower than previous forecasts. EnergyAustralia also submitted that the VENCorp 2009 VAPR forecasts imply that energy efficiency policies will be ineffective in reducing future electricity consumption.[49]

Origin Energy stated that the global economic downturn was moderate in Australia, and question this as a reason for the Victorian DNSPs' over forecasting of maximum demand in the current regulatory control period, noting particularly United Energy's assertion that the ORG and the ESCV's approaches to assessing maximum demand were appropriately 'conservative'.[50] Origin submitted that there should be correlation between the DNSPs' forecasts of maximum demand, energy consumption and customer numbers, noting that increased penetration of air conditioning should drive energy consumption higher, offsetting the impact of government energy efficiency policies.[51]

The Energy Users Association of Australia (EUAA) provided a comparison of the Victorian DNSPs' previous regulatory proposal energy forecasts submitted to the ORG, the ESCV and the AER, the regulators' decisions, and actual energy consumption. This comparison showed that the regulators' approved forecasts were closer to actual consumption than the DNSPs' proposals, and that the revised proposed energy forecasts for 2011–15 diverge greatly from recent history and from the AER's draft decision.[52]

The Energy Users Coalition of Victoria (EUCV) also provided a comparison of DNSP forecasts, regulator forecasts and actual consumption.[53] It submitted that AEMO's 2010 VAPR demonstrates that NIEIR, and even ACIL Tasman's, assumptions on growth may be too pessimistic, and that the 2010 VAPR forecast is for increasing consumption over the 2011–15 regulatory control period, in stark contrast to the Victorian DNSPs' forecasts for declining consumption.[54] It noted that in forecasting maximum demand AEMO took into account many of the same policies as NIEIR.

The EUCV also noted the potential for conflict between AEMO's role as both the market operator and the operator of the Victorian transmission system, which might affect the growth forecasts it prepares.[55] In relation to maximum demand, the EUCV

48 EnergyAustralia, Submission to the AER, August 2010, p. 17.
49 ibid.
50 Origin Energy, Submission to the AER, August 2010, pp. 1–2.
51 ibid., p. 2.
52 EUAA, Submission to the AER, August 2010, p. 17.
53 EUCV, Submission to the AER, August 2010, p. 58.
54 ibid., pp. 57–58.
55 ibid., pp. 59–60.

noted that the 2008–09 Victorian peak demand reflected a mix of high production before the onset of the GFC and very hot summer weather.[56]

As noted above, JEN made a late submission in September which addressed the AER's comparison of its 2006 maximum demand forecasts with the actual maximum demand.[57]

5.6.1.4 Consultant review

ACIL Tasman commented on CitiPower's and Powercor's statements that the AER should not compare the sum of their proposed spatial level maximum demand forecasts to system level forecasts.[58] ACIL Tasman stated that as system level forecasts are more capable of accounting for macro factors than spatial forecasts, reconciliation of the spatial forecasts to the system level forecasts is necessary.[59] This issue is discussed further in section 5.6.6.

ACIL Tasman also commented on Powercor's comparison of its 2006 forecasts with actual maximum demand over 2006–10. ACIL Tasman considered that it was unsurprising that actual maximum demand in 2009 was above Powercor's forecast, given that the weather at the time of the 2009 maximum demand was well above the 50 PoE level.[60]

5.6.1.5 Issues and AER considerations

Comparisons with AEMO forecasts

In late July 2010, AEMO (previously VENCorp) released its 2010 VAPR, which included revised maximum demand and consumption forecasts for 2010–11 to 2019–20.[61] The 2010 VAPR maximum demand forecasts reflect updated economic growth forecasts prepared by KPMG in March 2010, and revised population growth and air-conditioning sales assumptions.[62] The AER's consideration of the DNSPs' updated economic growth forecasts is detailed in section 5.6.3.

The AER has considered comments on the appropriateness of comparisons between AEMO and DNSP forecasts, given the differing purposes for which the forecasts are prepared, and the differing methodologies used in generating them. In preparing its 2009 and 2010 Victorian electricity consumption and maximum demand forecasts (which are consistent between the VAPR and the Electricity Statement of Opportunities), AEMO engaged both NIEIR and KPMG Econtech.

56 ibid., p. 60.
57 JEN, *JEN 2011–15 regulatory proposal: Response to stakeholder submissions*, September 2010, Attachment 3.
58 ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 62.
59 ibid., p. 62.
60 ibid., p. 84.
61 AEMO, *Victorian Annual Planning Report—Victoria's Electricity and Gas Transmission Network Planning Document*, July 2010.
62 ibid., p. 241.

NIEIR forecast the impact of energy and environment policy measures on energy and maximum demand, while KPMG prepared the economic scenario and electricity market inputs to the forecasts.[63]

NIEIR uses its 'PeakSim' model to prepare maximum demand forecasts for both AEMO and the Victorian DNSPs, and also uses a similar methodology when forecasting energy for AEMO and the Victorian DNSPs.[64]

The AER has reviewed the documented methodology applied by AEMO in forecasting maximum demand and energy, and considers its forecasts provide a valuable independent cross check of the forecasts submitted by the DNSPs. Ultimately the AER's draft decision identified issues with the DNSPs' forecasts which may explain some of the inconsistencies observed with AEMO's forecasts. However, they were not used to justify the rejection of or adjustments to the Victorian DNSPs' forecasts as implied by EnergyAustralia. In addition, the AER notes that it did not 'dogmatically substitute' the Victorian DNSPs' proposed forecasts with those prepared for other purposes. Rather, the AER took the DNSPs' forecasts as a starting point, and adjusted them only to the extent necessary to enable them to be approved in accordance with the NER.

Correlation between maximum demand and energy forecasts

Origin submitted that there shouldn't be a significant divergence between growth in maximum demand and energy consumption, noting that air conditioner penetration should drive energy consumption higher, similar to maximum demand. The AER agrees that the divergence between the Victorian DNSPs' consumption and maximum demand growth forecasts is significant. However, the major driver of the divergence is a change in average customer consumption behaviour, driven by various energy efficiency policies.

The divergence is also evident in the past few years of actual energy sales and maximum demand data. When comparing the forecasts on a policy free basis, as is done by ACIL Tasman for each DNSP, the difference between energy and maximum demand is eroded.[65] The AER has carefully considered the DNSPs' and NIEIR's assumptions on the impacts of each policy, detailed in section 5.6.4.

Maximum demand

The AER agrees that differences between the AEMO and Victorian DNSP forecasts could be explained by differences in the economic growth and policy impact assumptions (given KPMG Econtech prepared the economic forecasts underpinning the AEMO forecasts, and NIEIR notes it has differed from the AEMO forecasts in the policy assumptions applied to the Victorian DNSPs), and the timing in which the forecasts are prepared.

However, as demonstrated in figure 5.1 below, historically the sum of the Victorian DNSPs' terminal station maximum demands exhibits a clear and stable relationship to AEMO's native maximum demand. The AER considers that reviewing the

63 AEMO, *Victorian Annual Planning Report—Victoria's Electricity and Gas Transmission Network Planning Document*, July 2010, p. 93; VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009, p. 63.

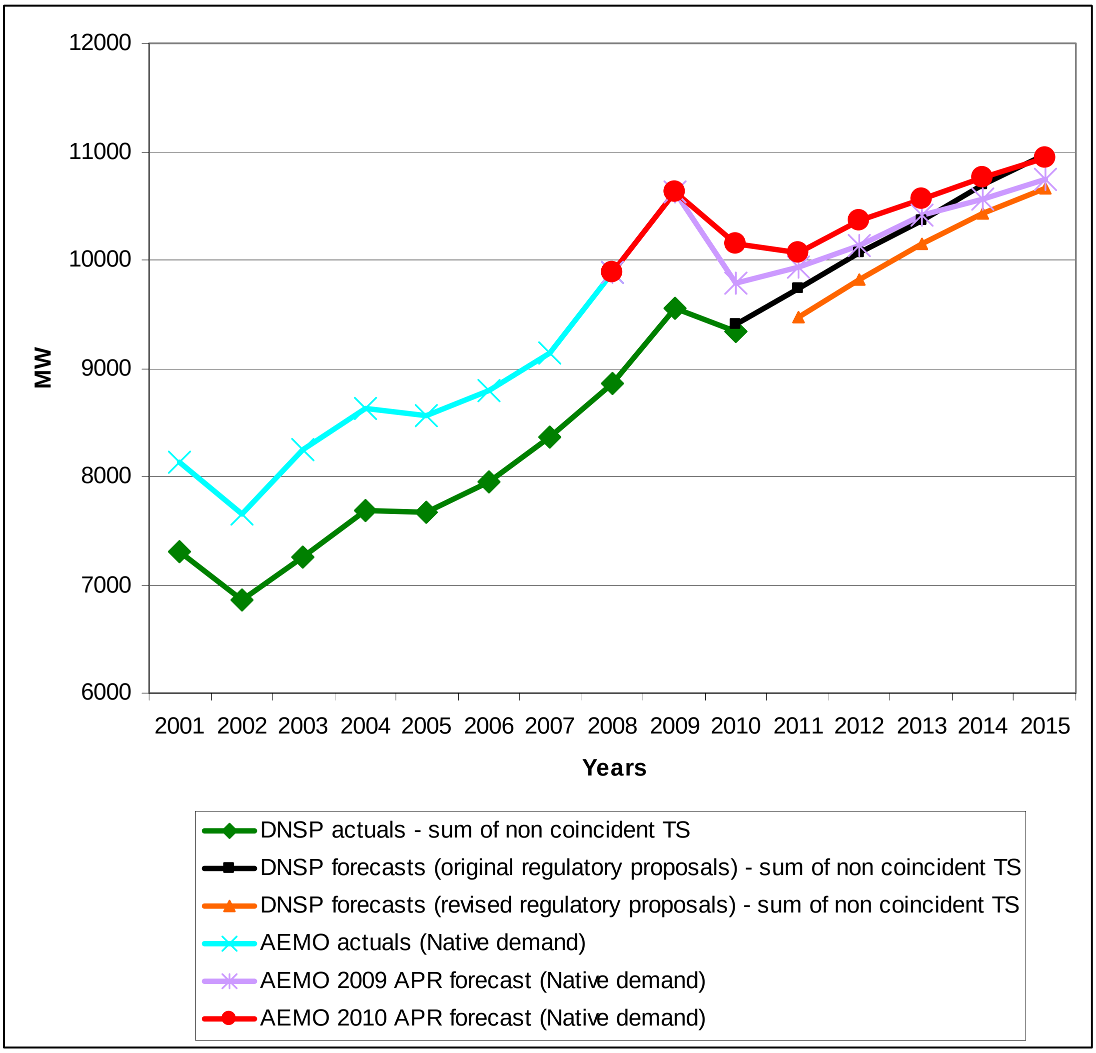
64 AER, *Draft decision*, June 2010, pp. 92-95.

65 See for example, ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 61.

relationship between actual and forecast data is a reasonable method of testing whether the DNSPs' maximum demand forecasts are consistent with AEMO's forecasts.

Figure 5.1 compares the Victorian DNSPs' initial and revised maximum demand forecasts (sum of terminal station forecasts) to AEMO's 2009 and 2010 VAPR.

Figure 5.1 Maximum demand—2009 VAPR, 2010 VAPR (native summer demand), DNSP forecasts and actuals (sum of terminal station forecasts)



Source: AEMO, *Victorian Annual Planning Report—Victoria's Electricity and Gas Transmission Network Planning Document*, July 2010, p. 94, table 4-1; VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009, tables 3–1 and E1–2; DNSPs' initial and revised RIN templates, sum of terminal station maximum demand forecasts.

Figure 5.1 demonstrates that the DNSPs' maximum demand forecasts predict a continuation of long term levels of growth over the forthcoming regulatory control period. It shows that since the AER's draft decision, AEMO's forecasts have been revised upwards, while the DNSPs' (in total) have revised their maximum demand forecasts downwards. That the forecast growth rates are now closer appears to reflect the DNSPs and AEMO updating their forecasts at similar times, whereas the previous forecasts were prepared at least six months apart.

While the forecasts no longer diverge, figure 5.1 still demonstrates that the consistent historical level of diversity between AEMO's system and the DNSPs' terminal station demands is not reflected in the forecasts. Given the central role played by NIEIR's modelling in preparing these forecasts, the differences highlight the importance of the particular input assumptions and post model adjustments applied.

United Energy stated that comparing system level maximum demand forecasts is problematic and that total maximum demand is of little value to its business plan. The AER acknowledges that a DNSP's network level maximum demand may not drive its specific capex requirements, however, it is important that macroeconomic variables such as economic growth, weather and the impact of various government policies are accounted for in the DNSPs' forecasts, as peak load is a key driver of capex.

The AER considers that the only transparent and credible way that such variables can be properly accounted for is by conducting a top down, high level forecast that compares historical trends and anticipates potential macro changes. As such, the AER carried out analysis of the network level (and sum of ZSS) maximum demands, comparing historical maximum demands to the forecasts, to identify general trends.

Grid Australia commented that the AER had not given sufficient weight to air conditioning load growth nor maximum demand growth in other jurisdictions in its draft decision forecasts.[66] The draft decision noted ACIL Tasman's view that while NIEIR's assumed air conditioning penetration was probably understated (due to its forecast slowing over the forthcoming regulatory control period), overall ACIL Tasman did not consider the assumed penetration rate unreasonable.[67]

The AER accepted NIEIR's assumptions on the impact of air conditioning on maximum demand in its draft decision.[68] For the final decision the AER has considered NIEIR's assumptions regarding air conditioning penetration, discussed in section 5.6.3, which were updated to include actual 2009 air conditioning sales. The AER agrees that air conditioning is a key driver of maximum demand.

In generating the Victorian DNSPs' maximum demand, energy and customer number forecasts, NIEIR took into account economic growth trends at the global, national, Victorian and network region levels. [69] In doing so, NIEIR has accounted for the growth trends in other jurisdictions in the NEM. NIEIR also took into account temperature data recorded each of the DNSPs' regions, which was discussed in the draft decision.[70]

In making its distribution determination, the AER has conducted a thorough review of the Victorian DNSPs' proposed forecasts, and has paid particular attention to the context of the Victorian DNSPs. However, the AER considers that the forecasts

66 Grid Australia, *Submission to the AER*, August 2010, pp. 4–5.
67 AER, *Draft decision*, June 2010, p. 105.
68 AER, *Draft decision*, June 2010, p. 106.
69 For example, see NIEIR, *Maximum summer demand forecasts for Jemena Electricity Networks to 2020*, June 2010, pp. 2–29.
70 AER, *Draft decision*, June 2010, pp. 94–95.

themselves appropriately reflect national economic conditions and Victorian temperature conditions over the forthcoming regulatory control period.

Energy consumption

The draft decision provided comparisons of the Victorian DNSPs' energy consumption forecasts against historical data and other independent forecasts only to provide some context to its analysis and demonstrate the significant variation from recent history being forecast by the Victorian DNSPs. The AER did not 'dogmatically' substitute the Victorian DNSPs' forecasts with other forecasts, as suggested by EnergyAustralia, rather it adjusted the DNSPs' forecasts based on an assessment of input assumptions and their impact on the forecasts.[71]

The AER acknowledges that AEMO's 2009 VAPR is now out of date, however the 2010 VAPR native energy forecast is higher than its 2009 forecast for the period 2011–15. AEMO stated that this is due to higher economic growth projections and a lower assumed impact of government policies.[72]

A number of submissions and DNSP revised regulatory proposals highlighted the different bases and purposes for which the 2009 VAPR energy forecasts were prepared. In particular, NIEIR pointed out that the Victoria wide forecast includes transmission connected customers, which have a material impact on the overall energy forecast. Figure 5.2 provides a comparison of the 2009 and 2010 VAPR native energy forecasts, the draft decision and Victorian DNSP initial and revised energy forecasts.

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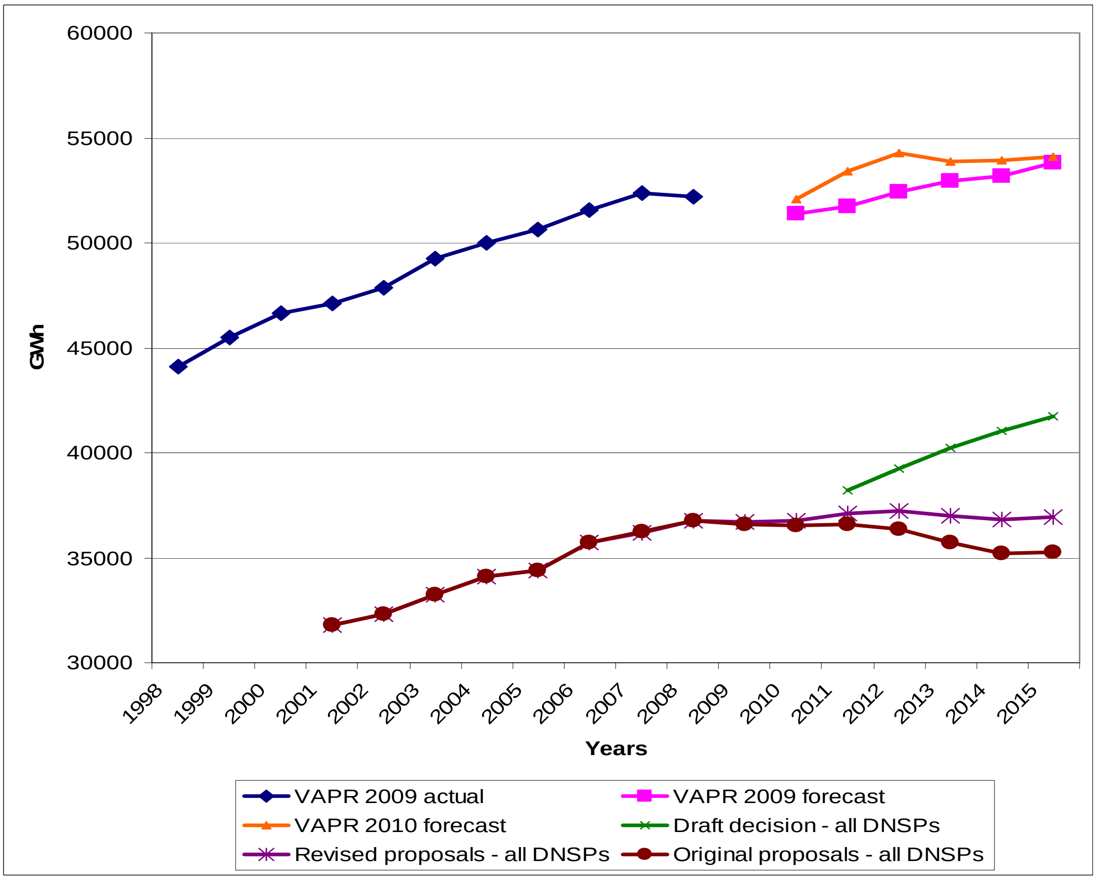
71 EnergyAustralia, *Submission to the AER*, August 2010, p. 17.

72 AEMO, *Victorian Annual Planning Report—Victoria's Electricity and Gas Transmission Network Planning Document*, July 2010, p. 99.

Figure 5.2 Energy consumption—2009 VAPR, 2010 VAPR (native energy demand), AER Draft decision, DNSP initial and revised forecasts (GWh)



Source: Victorian DNSPs' revised regulatory proposal RIN templates, sheet 6.3, table 3; AEMO, *Victorian Annual Planning Report—Victoria's Electricity and Gas Transmission Network Planning Document*, July 2010; VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009.

As for the maximum demand comparisons, figure 5.2 shows a relatively consistent rate of change between the historic system level and Victorian DNSP total consumption over 2001–10. The figure shows that the DNSPs' revised energy forecasts reflect rate of sales growth over 2010–15 that is more consistent with recent historical trends (2008–09) than the initial regulatory proposal energy forecasts, however is inconsistent with AEMO's higher rates of growth in 2011 and 2012. The forecasts consistently reflect that energy consumption will flatten out over 2012–15.

Figure 5.2 also highlights the relatively high rate of growth in the AER's draft decision energy forecasts, which in part reflects its adjustment for population growth inputs (discussed in section 5.6.3 below).

Visy submitted that JEN's forecasts do not reflect its own projections of flat energy consumption growth over the forthcoming regulatory control period.[73] The AER acknowledges Visy's concerns, and notes that the DNSPs' revised energy growth forecasts are higher than their original energy growth forecasts due to updated economic growth and population growth assumptions, as discussed in section 5.6.3.

[73] VISY, *Submission to the AER*, August 2010, pp. 1-2.

JEN's initial regulatory proposal forecast an average decline in consumption of 1.6 per cent over 2011–15, while its revised forecast is for a decline in average consumption of 0.8 per cent over the same period.[74] The AER considers JEN's revised energy forecast is a more accurate reflection of consumption over 2011–15.

Errors in historical comparisons data for maximum demand

The AER acknowledges that, as pointed out by CitiPower, Powercor and JEN, it relied on incorrect information in calculating the variance between the DNSPs' 2006 maximum demand forecasts and actual maximum demand over 2006–08. The source of the DNSPs' 2006 proposed forecasts, being table 4.3 on page 133 of the ESCV's 2006 EDPR is incorrectly labelled as the sum of ZSS forecasts, when it is in fact the sum of feeder level forecasts.[75]

Table 5.9 sets out the corrected total variance between the DNSPs' 2006 forecasts and actual maximum demand over 2006–08, and should be considered to replace table 5.7 of the draft decision.

Table 5.9 Total variance between DNSP proposed forecasts for 2006–10 and actuals—sum of raw/unadjusted ZSS maximum demand (%)

	Total variance
CitiPower	–0.0
Powercor	5.0
JEN	1.4
SP AusNet	7.5
United Energy	–12.8

Note: Negative numbers indicate actual maximum demand was lower than forecast.
Source: DNSPs' revised regulatory proposal RINs template 6.3, sum of table 17; DNSPs' regulatory proposals to the ESCV in December 2004, templates 10c to 10g.

Table 5.9 demonstrates that while United Energy over–forecast maximum demand in its regulatory proposal to the ESCV in 2004, the other Victorian DNSPs' proposed maximum demand forecasts were lower than or very close to actual maximum demand over 2006–10.[76]

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[74] JEN, *Initial regulatory proposal*, November 2009, RIN template 6.3, table 5; JEN, *Revised regulatory proposal*, July 2010, RIN template 6.3, table 3.

[75] CitiPower, *Revised regulatory proposal*, July 2010, p. 111-112; Powercor, *Revised regulatory proposal*, July 2010, p. 103-104; JEN, *Submission to the AER - JEN 2011-15 regulatory proposal: Response to Stakeholder Submissions*, 24 September 2010, Attachment 3.

[76] JEN's 24 September 2010 submission on stakeholder's submissions provided some comparisons of its maximum demand forecasts submitted to the ESCV for the 2006–10 regulatory control period with actual maximum demand over 2006–10, in MVA. Subsequent to this submission, JEN advised that due to a change in the way that it forecasts maximum demand, it is not possible to compare the MVA forecasts submitted to the ESCV for the 2006–10 regulatory control period with actual MVA maximum demand reported in JEN's original and revised RIN templates submitted to the AER. JEN then advised that this change does not affect its maximum demand forecast and actuals as reported in MW. Accordingly, table 5.4 provides a comparison of JEN's proposed

5.6.1.6 AER conclusion

The AER has considered the DNSPs' revised growth forecasts in relation to their historical growth trends, previous forecasts and against Victorian growth forecasts prepared by AEMO. The AER has used these comparisons to provide context around its detailed consideration of the forecasting methodologies, inputs and post-model policy adjustments, which are described in the following sections. These comparisons also contribute to the AER's understanding of the overall reasonableness of the Victorian DNSPs' growth forecasts, however, as noted above, the comparisons were not used to justify the rejection of or adjustments to the Victorian DNSPs' forecasts.

5.6.2 Methodological assessment

5.6.2.1 AER draft decision

The draft decision gave a detailed outline of NIEIR's and the Victorian DNSPs' maximum demand and energy forecasting methodologies. It compared the methodologies applied to the critical elements of best practice forecasting identified by ACIL Tasman.[77]

The main areas identified as methodologically inadequate were:

- lack of transparency and documentation of NIEIR's core forecasting methodologies
- DNSP maximum demand forecasts lacked appropriate reconciliation to NIEIR's top down forecasts, resulting in the forecasts not adequately accounting for macroeconomic variables such as economic growth, temperature sensitivity and the impact of policies
- input assumptions were outdated or conservative, in particular economic growth, population growth and CPRS implementation.

Despite these findings, the draft decision concluded that NIEIR's general approaches to forecasting maximum demand and energy were likely to be reasonable.[78] For NIEIR's customer number forecasts, the AER also noted the lack of transparency in methodology, however given the forecasts predict a continuation of recent trends, the AER considered they were likely to be reasonable, provided they be updated with more recent population and economic growth inputs.

5.6.2.2 Victorian DNSP revised regulatory proposals

As noted in the draft decision, CitiPower and Powercor submitted a report by Frontier Economics on 28 April 2010 outlining its review of NIEIR's methodology for forecasting energy consumption, as well as a report by NIEIR which gave an overview of its approaches to forecasting economic growth and energy

maximum demand forecast with the actuals as reported in MW within its RIN template 6.3, table 17. JEN, *Submission to the AER - JEN 2011-15 regulatory proposal: Response to Stakeholder Submissions*, 24 September 2010, Attachment 3; Origin, *Submission to the AER*, 19 August 2010; JEN, *Response to information request of 5 October 2010*, 7 October 2010; AER, *file note of phone conversation with Peter Wong*, 8 October 2010.

77 AER, *Draft decision*, June 2010, pp. 85–99.

78 ibid., pp. 95; 98–99.

consumption.[79] These reports were submitted too late to be considered in the draft decision, however the AER has reviewed them for this final decision.[80] JEN's revised regulatory proposal also attached and referenced these reports.[81]

SP AusNet did not comment on the AER's assessment of the methodologies applied by NIEIR and the Victorian DNSPs, aside from responding to the AER's reconciliation of the ZSS maximum demands with NIEIR's system level forecast.[82] The issues surrounding reconciliation between maximum demand forecasts are discussed in section 5.6.6.

5.6.2.3 Submissions

None of the submissions commented on specific methodological issues relating to the DNSPs' growth forecasts.

5.6.2.4 Consultant review

ACIL Tasman's initial reports found that NIEIR's core models for forecasting energy and customer numbers were likely to be reasonable and produce reasonable forecasts (subject to the updating of economic growth and population inputs, and excluding to the post-model adjustments made to account for the impact of policies).

Accordingly, ACIL Tasman did not comment extensively on NIEIR's forecasting methodologies in its response to the revised regulatory proposals, aside from noting that Frontier reached similar conclusions on the lack of transparency of NIEIR's energy forecast model and the general reasonableness of the methodology applied.[83]

5.6.2.5 Issues and AER considerations

The AER has considered the additional information provided by CitiPower, Powercor and JEN on NIEIR's energy forecasting methodology, in reports prepared by Frontier and NIEIR itself. The AER also notes that CitiPower and Powercor provided a brief letter from Frontier Economics stating that NIEIR's own summary of its methodology was considered after the completion of its report, but that the additional information did not conflict with nor require any amendment to Frontier Economics' findings on NIEIR's methodology.[84]

Frontier Economics' review included a high level assessment of NIEIR's methodology for developing Powercor's electricity consumption. Frontier's assessment was based on information that was also provided to the AER and ACIL Tasman prior to the draft decision (including NIEIR's initial reports for CitiPower and Powercor), as well as

[79] AER, *Draft decision*, June 2010, p. 94; Frontier Economics, *Review of NIEIR's methodology for forecasting electricity consumption—a report prepared for Powercor Australia*, April 2010; NIEIR, *Overview of economic and energy forecasting methodologies used at the National Institute of Economic and Industry Research*, April 2010.

[80] CitiPower, *Revised regulatory proposal*, July 2010, pp. 94–95; Powercor, *Revised regulatory proposal*, July 2010, p. 87.

[81] JEN, *Revised regulatory proposal*, July 2010, pp. 43-45.

[82] SP AusNet, *Revised regulatory proposal*, July 2010, pp. 62-64.

[83] ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 8–10.

[84] Frontier Economics, *Letter to Matthew Serpell*, 10 May 2010.

some additional notes prepared by NIEIR in 2009, and some information that is available on NIEIR's website.[85]

Overall, Frontier found NIEIR's modelling system meets world's best practice standards, capturing the main drivers of electricity sales and producing highly disaggregated forecasts.[86]

The AER notes that after reviewing similar information as the AER and ACIL Tasman on NIEIR's methodology, Frontier has reached the same conclusion as the AER and ACIL Tasman that NIEIR's approach is reasonable. Frontier also noted the lack of consolidated documentation of NIEIR's approach, and recommended NIEIR develop a 'technical guide' to its models.[87]

NIEIR's overview of its economic and energy forecasting methodologies provided a detailed summary of the theoretical background of NIEIR's core models, and some history on the development of the models.[88] It provided a summary of the international, national, state and regional (local government area) economic forecasting models that produce inputs to NIEIR's maximum demand and energy forecasts for the Victorian DNSPs.

It also described the process NIEIR adopts when forecasting energy sector prices (electricity and gas), which both impact on the demand for electricity.[89] A description of the energy model, as well as the weather normalisation process and NIEIR's data management and quality control mechanisms were also provided.[90]

The AER considers that NIEIR's overview is a useful description and justification for the general forecasting practices carried out by NIEIR, however the AER notes that it does not provide detail on each step NIEIR applied in generating growth forecasts for the Victorian DNSPs, nor is it a technical guidebook as suggested by Frontier. The AER also notes that this overview and Frontier's report are not sufficient substitutes for an independent technical review of NIEIR's models, which would only be achieved by an independent party reviewing and testing the models themselves.

5.6.2.6 AER conclusion

After considering the additional information on NIEIR's forecasting methodology for energy consumption and economic growth, the AER maintains its draft decision position that NIEIR's core models are reasonable and likely to produce forecasts that reflect a realistic expectation of demand, for the purposes of the AER's assessment under clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER.

5.6.3 NIEIR's input assumptions

NIEIR's growth forecasts are based on a number of input assumptions for each Victorian DNSP's region, including:

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[85] Frontier Economics, *Review of NIEIR's methodology for forecasting electricity consumption—Prepared for Powercor Australia*, April 2010, Annexure 3.

[86] ibid., p. ii.

[87] ibid., p. iii.

[88] NIEIR, *Overview of economic and energy forecasting methodologies used at the National Institute of Economic and Industry Research*, April 2010, pp. 1–17.

[89] ibid., pp. 19–25.

[90] ibid., pp. 29–31.

- economic growth or gross state product (GSP)
- air-conditioning sales
- population growth.

The following section outlines the AER's consideration of NIEIR's revised assumptions regarding each of these factors, which feed into the Victorian DNSPs' revised maximum demand, energy and customer number forecasts.

5.6.3.1 AER draft decision

Noting the limited data provided by NIEIR on its methodology, for the draft decision the AER assessed each of NIEIR's input assumptions, their application and their impact on the reasonableness of the Victorian DNSPs' proposed growth forecasts. Each of these inputs is discussed below.

Economic growth

The AER considered that NIEIR's November 2009 forecasts were unreasonable as they reflected outdated economic growth assumptions. The draft decision noted the AER's expectation that updated forecasts would be incorporated into the DNSPs' revised regulatory proposals.

The AER considered that NIEIR's assumption of a five year business cycle also appeared unusually conservative when compared to historical observations.[91] The AER also noted the business cycles between 1970 and 1990 appear to range from six to eight years, and therefore that a longer business cycle would reflect a more reasonable expectation.

Growth in air conditioning sales

The draft decision noted the AER's agreement with ACIL Tasman's view that growth in air conditioning sales in Victoria would remain strong for a number of years before market saturation is reached. However, the AER also considered that NIEIR's forecast of a slowdown in air conditioner sales was reasonable.

Population growth

The AER considered that NIEIR's population growth forecasts were unreasonably low when compared to historical and projected growth forecasts from the ABS and the Victorian Department of Treasury and Finance (DTF). In rejecting NIEIR's forecasts, the AER stated that they should instead be based on a population growth assumption that matches the ABS ‘series B’ (medium growth) forecasts for Victoria.[92]

For the purposes of determining the required adjustments to the forecasts for the draft decision, the AER used an ad hoc population adjustment as calculated by ACIL Tasman. The AER noted that applying the resulting MWh increases to the forecasts may be an imperfect approach to incorporating a revised population growth assumption, however was necessary in the absence of sufficient information on NIEIR's models to apply this as a revised input assumption.

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91 AER, *Draft decision*, June 2010, pp. 102–104
92 ibid., p. 108

The DNSPs' were provided the opportunity to propose an alternative approach to incorporating these population growth inputs in their revised regulatory proposals.[93]

5.6.3.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs argued the AER's post-model adjustment to its energy forecasts was unreasonable, and significantly overstated the impact of changes in population forecasts.

As noted above in section 5.3, the Victorian DNSPs engaged NIEIR to produce updated forecasts of maximum demand, energy consumption and customers numbers over the next regulatory control period. The Victorian DNSPs noted that in addressing the matters raised in the AER's draft decision, NIEIR's updated energy consumption forecasts:

- reflect average population growth forecast of 1.4 per cent, consistent with the ABS series B (medium growth) forecasts
- reflect GSP forecasts which take into account recent economic conditions, which are broadly consistent with the forecasts of the Victorian DTF.[94]

In terms of NIEIR's updated population growth forecasts, JEN explained that:

> the impacts on NIEIR's updated forecasts should be a calculation on the difference between NIEIR's growth forecasts (1.2 per cent in 2011–12) and ABS growth forecasts (1.4 per cent). Therefore, the adjustment should then be on the 0.2 per cent difference between the two projections.[95]

For NIEIR's updated economic growth forecasts, CitiPower and Powercor noted:

> …while in November 2009 NIEIR considered there would be relatively slow economic growth virtually across the entire period in Victoria in 2011-15, NIEIR indicated in its June 2010 report that growth was expected to be stronger, particularly in the early part of the next regulatory control period.[96]

JEN also noted:

> 'NIEIR's average annual GSP growth over the period of 2.6 per cent exceeds the comparable forecast of KPMG Econtech (cited by ACIL Tasman) who have forecast an average of 2.2 per cent in its medium scenario.'[97]

The Victorian DNSPs contended that the AER should accept NIEIR's revised energy consumption forecasts for their respective proposals because:

- the AER has accepted NIEIR's methodology for forecasting energy consumption to be reasonable

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93 ibid., pp. 108–109

94 CitiPower, *Revised regulatory proposal*, July 2010, p. 96; Powercor, *Revised regulatory proposal*, July 2010, p. 89; JEN, *Revised regulatory proposal*, July 2010, p. 45; SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 57; United Energy, *Revised regulatory proposal*, p. 271.

95 JEN, *Revised regulatory proposal*, July 2010, p. 45.

96 CitiPower, *Revised regulatory proposal*, July 2010, p. 97; Powercor, *Revised regulatory proposal*, July 2010, pp. 89–90.

97 JEN, *Revised regulatory proposal*, July 2010, p. 56.

- the updated population growth forecasts and economic growth forecasts are broadly consistent with the recommendations in the AER's draft decision
- these revised forecasts are more appropriate than the AER's adjustments because they are made as inputs into NIEIR's modelling framework
- NIEIR’s methodology appropriately incorporates the interdependencies between key drivers of the model.[98]

5.6.3.3 Submissions

United Energy provided a report by Marsden Jacob Associates (MJA) as a submission on its own proposal and the AER's draft decision. MJA was engaged by United Energy to provide an independent assessment of the AER’s adjustments to its initial energy sales volume forecasts.[99] In its report, MJA concluded that:

- ACIL Tasman's adjustment approach does not meet the criteria of 'best estimates' and leads to a biased outcome, as it fails to recognise a multitude of interrelated factors that link energy consumption with economic activity[100]
- the most appropriate way to develop a 'best estimate' is to incorporate the ABS series B population data as an input into NIEIR's base energy forecasting model
- ACIL Tasman erroneously adopted ABS Series A (high growth) population projections in its estimates instead of Series B (medium growth), which resulted in an overstated energy forecast.[101]

5.6.3.4 Consultant review

Economic growth forecasts

ACIL Tasman compared NIEIR’s revised economic forecast with those of the Victorian DTF, and AEMO (prepared by KPMG Econtech). ACIL Tasman observed that NIEIR’s revised forecasts predict that the Victorian economy will grow faster than forecast by DTF and AEMO for the early part of the forthcoming regulatory control period, before slowing to be the lowest of the three forecasts in 2014–15.[102]

Figure 5.3 provides a graphical comparison of the economic growth forecasts, including the high and low case forecasts prepared by AEMO and the average NIEIR growth rate over the forthcoming regulatory control period.

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98 CitiPower, *Revised regulatory proposal*, July 2010, p. 96; Powercor, *Revised regulatory proposal*, July 2010, p. 89; JEN, *Revised regulatory proposal*, July 2010, p. 45; SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 57; United Energy, *Revised regulatory proposal*, p. 271.

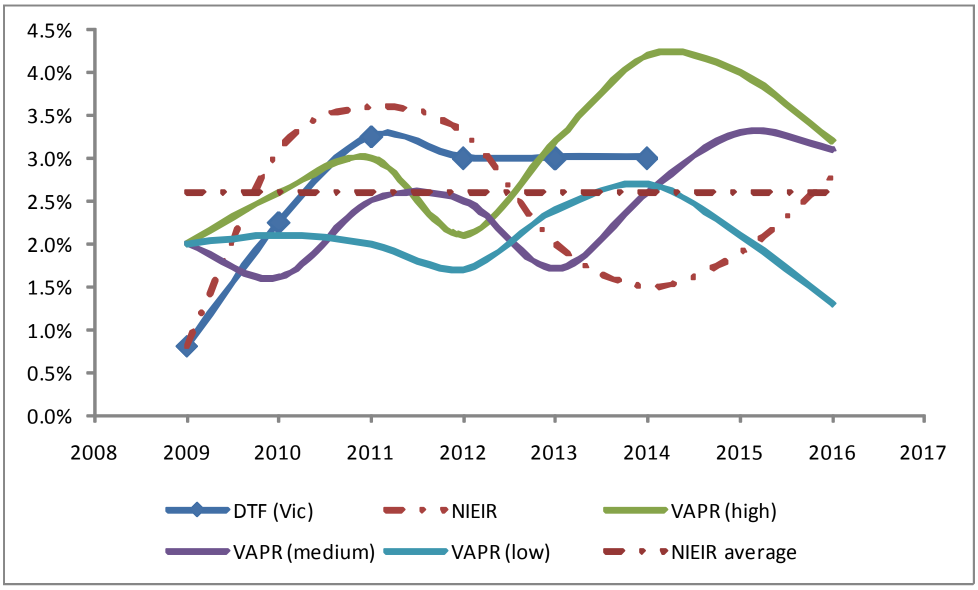
99 Marsden Jacob Associates, *AER Treatment of UED Energy Sales Volume Forecasts*, 20 August 2010, p. 3.

100 Marsden Jacob Associates, *AER Treatment of UED Energy Sales Volume Forecasts*, 20 August 2010, p. 7.

101 ibid., p. 9.

102 ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 11–13.

Figure 5.3 ACIL Tasman's comparison of Victorian economic growth forecasts and NIEIR's average population growth rate, 2009 to 2016



Source: Department of Treasury and Finance (DTF) *2010-11 Budget Paper No. 2, Strategy and Outlook*, p. 19; NIEIR, *Electricity sales and customer numbers for the Citipower region to 2019*, June 2010, p. 27; Australian Energy Market Operator, *Victorian Annual Planning Report*, June 2010, p. 245 (in ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 13.).

ACIL Tasman noted that NIEIR's average growth rate is approximately consistent with the average of AEMO's medium growth rate scenario. ACIL Tasman concluded that NIEIR's revised economic growth forecasts are a reasonable basis for the Victorian DNSPs' growth forecasts.[103]

Population growth forecasts

In its initial advice prior to the AER's draft decision, ACIL Tasman recommended that the DNSPs' revised energy and customer number forecasts should be prepared using the ABS series B population forecasts as an input.[104]

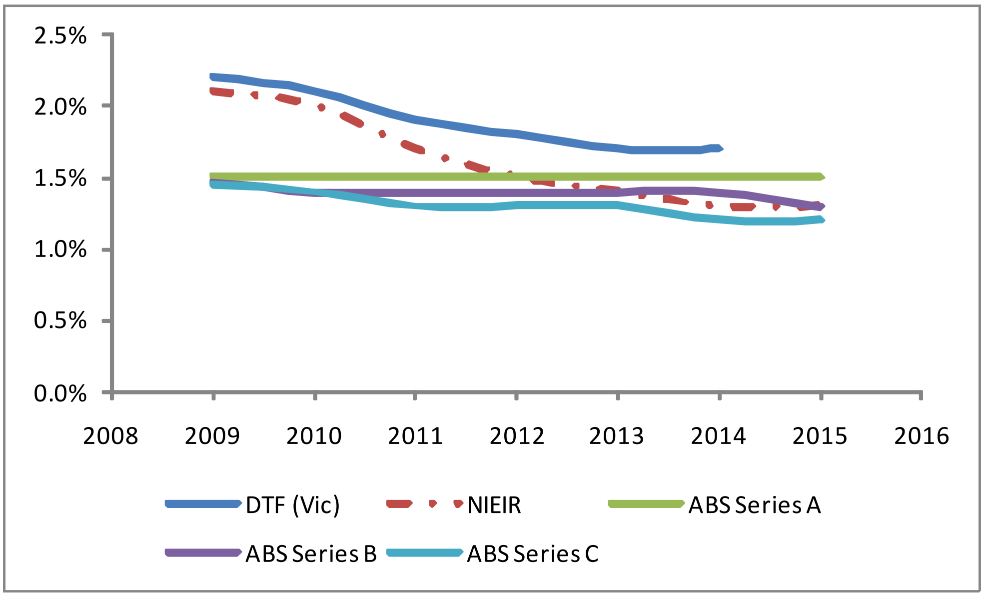
ACIL Tasman acknowledged the error it made in calculating the population adjustments, using ABS series A instead of series B, which resulted in the draft decision energy forecasts being overstated.[105] ACIL Tasman also commented on the shortcomings identified within the revised regulatory proposals, Frontier's and MJA's reports regarding the methodology applied for adjusting the forecasts. ACIL Tasman noted that it had also listed these shortcomings in its original report, which were recognised by the AER when making its draft decision.[106]

ACIL Tasman noted that the revised population growth assumptions are more reflective of recent conditions in Victoria than NIEIR's original assumptions.[107]

103 ibid., p. 12.
104 ibid., p. 13.
105 ibid., p. 15.
106 ibid., p. 16.
107 ibid., p. 14.

Figure 5.4 provides a graphical comparison of NIEIR's population growth forecasts with those of the Victorian DTF and the ABS series A, B and C, including the average of NIEIR's forecasts over the period 2009 to 2015.

Figure 5.4 ACIL Tasman's comparison of Victorian population growth forecasts and NIEIR's average population growth rate, 2009 to 2015



Source: ABS, *3220.0 Population Projections, Australia 2006 to 2101*; Victorian Treasury, *Victorian Budget Papers 2009-10*, NIEIR, *Electricity sales and customer numbers to 2019 for the JEN Electricity region*, June 2010.

ACIL Tasman considered that NIEIR's revised population forecasts:

- are slightly less optimistic than the Victorian Government's forecasts in the early part of the forthcoming regulatory control period
- decrease relative to the Victorian DTF's forecasts as time passes, consistent with NIEIR's forecast of lower economic growth later in the forthcoming regulatory control period
- are consistent, in average terms, with the ABS Series B forecasts.[108]

ACIL Tasman concluded that, given NIEIR's population forecasts are approximately consistent with the ABS series B forecasts, they are likely to provide a reasonable forecast of population growth over the 2011–15 regulatory control period.[109]

5.6.3.5 Issues and AER considerations

Economic growth forecasts

In assessing the revised economic growth rates used by NIEIR, the AER and ACIL Tasman have considered the most recent forecast growth rates used by the Victorian DTF, and economic forecasts prepared by AEMO in its 2010 VAPR (see figure 1.2).

108 ibid.
109 ibid., p. 15.

The AER observes that NIEIR’s average growth rate of 2.6 per cent over the period 2010 to 2016 is below the average rate of 2.9 per cent produced by Victorian DTF.

However, the Victorian DTF’s average growth rate does not include forecasts for 2015 and 2016, for which NIEIR projects lower growth than the first few years of the forthcoming regulatory period, which draws NIEIR's average growth rate over the period down.

The AER observes that NIEIR’s average growth rate over the forthcoming regulatory control period is more consistent with the VAPR’s medium scenario average growth rate of 2.5 per cent.[110] Therefore the AER does not consider NIEIR's average growth rate of 2.6 per cent over 2010–2015 to be unreasonable as a basis for projecting the Victorian DNSPs' growth forecasts for the forthcoming regulatory control period.

NIEIR's revised economic growth forecasts are for strong growth of between 3.1 per cent and 3.6 per cent (average of 3.3 per cent) during 2010 to 2012. This is followed by forecast annual growth of between 1.5 per cent and 2.0 per cent (average of 1.8 per cent) in the remaining years of the forthcoming regulatory control period.

The AER notes this is in direct contrast with the comparative growth rates of AEMO's VAPR (medium case) which provides 3-year average growth rates of 2.2 per cent and 2.5 per cent during the same period. On balance, it appears that while NIEIR's forecast economic growth rates are higher than AEMO's forecast growth during 2010–12, AEMO's growth rates are higher than NIEIR's forecasts during 2013–15.

Overall, NIEIR's updated economic growth assumptions are based on a more optimistic outlook than those used for the DNSPs' original proposed forecasts.[111] This is consistent with comments by the Victorian DTF:

> Since the May budget, the global economic outlook has stabilised and downside risks to growth have eased. Asset prices are rising and business and consumer confidence have recovered.[112]

Although it further states "there is still considerable vulnerability and uncertainty in the global outlook", the Victorian DTF's average projected growth rates of 2.9 per cent (over 2010–14) are similar to, although marginally higher than, NIEIR's forecast growth of 2.7 per cent over the same period.

NIEIR has revised its forecasts to reflect more recent economic conditions, as provided in Victorian DTF's revised forecast growth rates and AEMO's revised VAPR. NIEIR's forecasts on average are also approximately consistent with the average of AEMO's medium case growth scenario. Accordingly the AER does not consider NIEIR's revised June 2010 forecasts to be unreasonable as an input into modelling revised growth forecasts for the Victorian DNSPs.

Neither the DNSPs nor NIEIR provided a response to the AER's draft decision regarding the length of economic business cycles.[113] In the updated economic growth

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110 AEMO, *Victorian Annual Planning Report*, June 2010, p. 245.
111 AER, *Draft decision*, June 2010, pp. 103–104.
112 Victorian DTF, *2009-10 Budget update*, 26 November 2009.
113 AER, *Draft decision*, June 2010, pp. 103–104.

forecasts, NIEIR is no longer forecasting that economic growth will fall to zero in the forthcoming regulatory control period. This alleviates the AER's concern regarding the short business cycle, discussed in the draft decision.

The AER also notes that NIEIR's revised economic growth rates will result in an increase in each of the Victorian DNSPs' forecasts of maximum demand, energy consumption, and customer number growth.

Growth in air conditioning sales

The draft decision provided details on NIEIR's PeakSim model used for forecasting the Victorian DNSPs' summer and winter peak demands.[114] A key driver of PeakSim's projections is growth in temperature sensitive load, which is primarily driven by air conditioning sales.[115]

NIEIR updated its summer maximum demand forecasts for the Victorian DNSPs following the draft decision, as part of its June 2010 forecasts. NIEIR stated that the original forecasts were prepared close to the GFC, and accordingly anticipated that actual sales of air conditioning equipment would fall in 2009–10. However, 2009–10 summer temperatures in Victoria were on average above a 10 per cent POE temperature, which combined with hot temperatures in November 2009, led to record air conditioning sales in Victoria for that year.[116]

NIEIR reported that actual maximum demand was some 160 MW above that forecast in 2009.[117] This implies that NIEIR updated its air conditioner sales forecasts to account for the 2009 data. However, NIEIR's revised reports do not mention any update to the sales data.

NIEIR's forecasts of temperature sensitive load, provided in the original and revised reports, indicate NIEIR has updated the forecasts beyond just economic growth and population, as the temperature sensitive load forecast has increased in itself.[118] For example, NIEIR increased its forecast of United Energy's temperature sensitive load by 7 per cent on average over 2010–15, between original and revised reports.[119]

In its initial advice prior to the draft decision, ACIL Tasman included some analysis of NIEIR's assumptions on air conditioning penetration as compared to ABS and Department of the Environment, Water, Heritage and the Arts (DEWHA) data on energy use.[120] It was concluded that NIEIR's projection of air conditioning sales growth was consistent with the ABS and DEWHA data.

The AER agrees that it was reasonable for NIEIR to update the forecasts to account for the 2009 air conditioning sales, given the impact that this is likely to have on

114 ibid., pp. 92–95.
115 For example see NIEIR, *Maximum summer demand forecasts for Jemena Electricity Networks to 2020*, June 2010, pp. 31–33.
116 For example see NIEIR, *Maximum summer demand forecasts for Jemena Electricity Networks to 2020*, June 2010, p. 1.
117 ibid.
118 NIEIR forecasts temperature sensitive load separately to total maximum demand.
119 NIEIR, *Maximum summer demand forecasts for United Energy to 2020*, November 2009, table 8.2; NIEIR, *Maximum summer demand forecasts for United Energy to 2020*, June 2010, table 7.1.
120 ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of maximum demand forecasts, Report prepared for the AER*, 19 April 2010, p. 26.

maximum demand growth going forward. Accordingly, the AER considers that NIEIR's updated growth in air conditioning sales are reasonable inputs into the Victorian DNSPs' summer and winter peak demand forecasts.

The AER also notes that air conditioning sales forecasts were updated slightly due to affects of the Mandatory Energy Performance Standards (MEPS) on air conditioning. This is discussed in section 5.6.4 below.

Population growth forecasts

As outlined above, NIEIR assumes a fall in population growth during the latter part of the forthcoming regulatory control period. Victorian DTF forecast similar population growth over years 2009–11, however the drop off in years 2012–14 is not as pronounced as within NIEIR's forecast. The AER notes that these trends are consistent with NIEIR’s own forecast of lower economic growth from 2013–15.[121]

NIEIR's revised population projections are for an average annual population growth rate of 1.4 per cent in Victoria. As figure 5.4 shows, this average growth is less optimistic than the Victorian DTF’s forecasts and marginally less optimistic than the ABS Series A population forecasts. However the AER notes that the average growth is broadly similar with the ABS series B forecasts. This is consistent with the AER’s draft decision that NIEIR’s population growth forecasts were unreasonably low, and should at least be comparable to those in ABS Series B.

Therefore, the AER considers NIEIR’s updated population growth forecasts to be a reasonable input into its energy and customer number forecasts for the Victorian DNSPs.

In response to the Victorian DNSPs' and MJA's concerns regarding the population adjustments in the AER’s draft decision, the AER notes that:

- ACIL Tasman calculated adjustments to the DNSPs’ electricity sales forecasts to amend the population growth assumptions within the initial forecasts, as requested by the AER. The adjustments are set out in table 5.15 of the draft decision[122]

- ACIL Tasman did not recommend that the AER rely on these adjustments in making its final decision on the DNSPs' energy forecasts, rather recommended that the DNSPs provide revised energy forecasts using NIEIR’s model and the ABS series B population forecasts[123]

- In its revised report, ACIL Tasman acknowledged an error in its calculations as highlighted by MJA, in that they were based on the ABS series A, rather than the series B population forecasts as intended. This resulted in the draft decision electricity sales forecasts being overstated[124]

The AER acknowledges that the population adjustments made to the DNSPs' energy forecasts involved various shortcomings, which the AER listed in the draft

[121] For example see NIEIR, *Electricity sales and customer number forecasts to 2019 for the JEN Electricity region*, June 2010, p. 26.
[122] ACIL Tasman, *Review of electricity sale and customer numbers forecasts*, April 2010, pp. 14–15.
[123] ibid., p. 15.
[124] ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 15.

decision.[125] The AER also acknowledges that the population adjustments resulted in some anomalous outcomes in the draft decision energy forecasts, which particularly affected United Energy. Notwithstanding the errors identified in its calculation, the AER maintains that its adjustment was its best alternative given the lack of access to NIEIR's forecasting models, which the AER requested shortly after the DNSPs lodged their initial proposals in November 2009.

5.6.3.6 AER conclusion

The AER and ACIL Tasman have considered the updates made by NIEIR to various inputs in preparing the Victorian DNSPs' revised maximum demand, energy and customer number forecasts. The AER considers that:

- as NIEIR’s economic growth forecasts are, on average, broadly consistent with those in AEMO’s VAPR 2010 medium scenario, they are likely to be a reasonable input into the Victorian DNSPs’ growth forecasts
- NIEIR's revised temperature sensitive load forecast, reflecting the strong growth in air conditioner sales in 2009, is likely to be reasonable
- as NIEIR's revised population growth forecasts are generally in line with the ABS series B growth forecasts, they are likely to be reasonable inputs into NIEIR's energy and customer number forecasts.

Accordingly, the AER considers that based on its assessment, NIEIR's revised input assumptions provide a reasonable basis for projecting the Victorian DNSPs' maximum demand, energy consumption and customer number forecasts. The inputs produce a realistic expectation of the demand forecasts required to achieve the opex and capex objectives for the purposes of the AER's assessment under clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER.

In regards to energy and customer number forecasts, the AER considers NIEIR's input assumptions are appropriate as they affect inputs into the PTRM for the purposes of clause 6.12.1(10) of the NER.

5.6.4 Post model policy adjustments and the CPRS

This section discusses NIEIR's assumptions regarding the impact of government policies on its forecasts, including both in-model adjustments made for the CPRS and hot water policies, as well as various post-model policy adjustments. Most of the policies considered in this section do not have any historical precedents and therefore there is a high level of uncertainty in respect of their likely impact. The impact of the AMI rollout is discussed separately in section 5.5.7 below.

5.6.4.1 AER draft decision

The draft decision detailed the AER's assessment of NIEIR's post model policy adjustments to the energy and maximum demand forecasts.[126] The AER and ACIL Tasman considered the policy adjustments made by NIEIR were acceptable, except for the adjustments for the CPRS, the insulation rebate, the Mandatory Energy

[125] AER, *Draft decision*, June 2010, p. 108.
[126] ibid., pp. 109–121.

Performance Standards (MEPs) for lighting, and the one watt standby targets. The draft decision also noted that the reductions to account for hot water policy listed in NIEIR's initial reports were misleading, as the policy is actually accounted for as input assumptions of hot water load.[127]

The AER was unable to review the assumptions made to account for hot water policy as they were not quantified in the information provided by NIEIR, however, the AER did not make any adjustments to NIEIR's energy forecasts of hot water policies in the draft decision.[128]

The draft decision rejected NIEIR's assumptions on the following policy impacts:

- CPRS—NIEIR's assumption on the introduction of the CPRS was outdated, given more recent Australian Government announcements. The draft decision noted the AER's expectation that the DNSPs would engage NIEIR to update its policy assumptions in revised forecasts, including the assumed start date for the CPRS.[129]

- MEPs for lighting—the estimates provided by NIEIR with respect to the impact of MEPs for lighting on maximum demand were reasonable, however the forecast impact on energy consumption should be constrained to the Australian Government's modelled impacts in the RIS. The AER amended the DNSPs' assumed impact of the MEPs lighting policy on energy to account for this difference as shown in tables 5.5 and 5.6 below.[130]

- Insulation rebate scheme—as the Australian Government announced the discontinuation of the insulation rebate scheme on 19 February 2010, the draft decision stated that adjustments to the growth forecasts for the insulation target scheme should be removed.[131]

- One watt standby target—as NIEIR had not demonstrated evidence of a government policy to implement a one watt target, the forecast reductions in energy and maximum demand attributed to the one watt target were disregarded.[132]

Tables 5.10 and 5.11 summarise the AER's adjustments to NIEIR's forecasts arising from its considerations of policy impacts in the draft decision.

[127] ibid., p. 96, 120.
[128] ibid., p. 96, 120.
[129] ibid., pp. 115–117.
[130] ibid., pp. 112–115.
[131] ibid., pp. 120–121.
[132] ibid., p. 120.

Table 5.10 AER forecast cumulative policy adjustments, maximum demand (MW)

	2011	2012	2013	2014	2015
Total policy impacts—DNSPs	–51	–74	–95	–114	–131
AER adjustment—standby power	3	10	16	23	29
AER adjustment—insulation	21	25	25	25	25
Total policy impacts—draft decision	–27	–39	–54	–66	–77

Source: NIEIR maximum demand reports tables 6.3 and 6.6; AER analysis.

Table 5.11 AER forecast cumulative policy adjustments, energy consumption (GWh)

	2011	2012	2013	2014	2015
Total policy impacts—DNSPs	–720	–1009	–1214	–1339	–1434
AER adjustment—MEPs lighting	0	0	23	37	51
AER adjustment—standby power	27	82	137	173	190
AER adjustment—insulation	111	134	134	134	134
Total policy impacts—draft decision	–582	–793	–920	–995	–1059

Source: NIEIR energy consumption reports tables 6.2 and 6.5; AER analysis.

5.6.4.2 Victorian DNSP revised regulatory proposals

In response to the draft decision, NIEIR updated some of post model policy adjustments in its revised reports for the Victorian DNSPs. NIEIR's revised reports also address the potential rebound effects of the various policies, which was highlighted by ACIL Tasman. NIEIR revised its forecasts for the following policies:

- MEPs for lighting—NIEIR's revised forecast reduced the assumed impact of the policy on energy by 15 per cent.
- MEPs for air conditioning—NIEIR slightly increased the assumed energy savings from MEPs.
- Insulation rebate scheme—NIEIR's revised forecast allows a one-off effect in 2010 for the houses that had received insulation under the scheme prior to its cancellation.
- PV—NIEIR decreased its profile of energy savings from PV installations over the 2009-10 to 2011-12 period.
- Electric vehicles—NIEIR's revised forecast reduced the assumed impact of electric vehicles which reduced the estimated impact on energy consumption.

Tables 5.12 and 5.13 summarise NIEIR's revised forecasts for the cumulative policy adjustments on maximum demand and energy consumption for the forthcoming regulatory period.

Table 5.12 NIEIR revised forecast cumulative policy adjustments (excluding AMI), maximum demand (MW)

Policy (MW)	2011	2012	2013	2014	2015
Standby power	–3.4	–10	–16.6	–23.2	–29.8
Insulation	0	0	0	0	0
Photovoltaics	–4.4	–8.1	–10.8	–12.9	–14.5
MEPs air conditioners	–9.4	–19.8	–31.4	–41.5	–50.9
6 star building standards	0	0	0	0	0
Total policy impacts	**–17.2**	**–37.9**	**–58.8**	**–77.6**	**–95.2**

Note: The impact of the insulation policy on maximum demand was accounted for by NIEIR as a one-off adjustment in 2009 of –4.12 MW, and accordingly does not appear as a cumulative adjustment over 2011–15.

Source: NIEIR revised maximum demand reports tables 6.3 and 6.6, AER analysis.

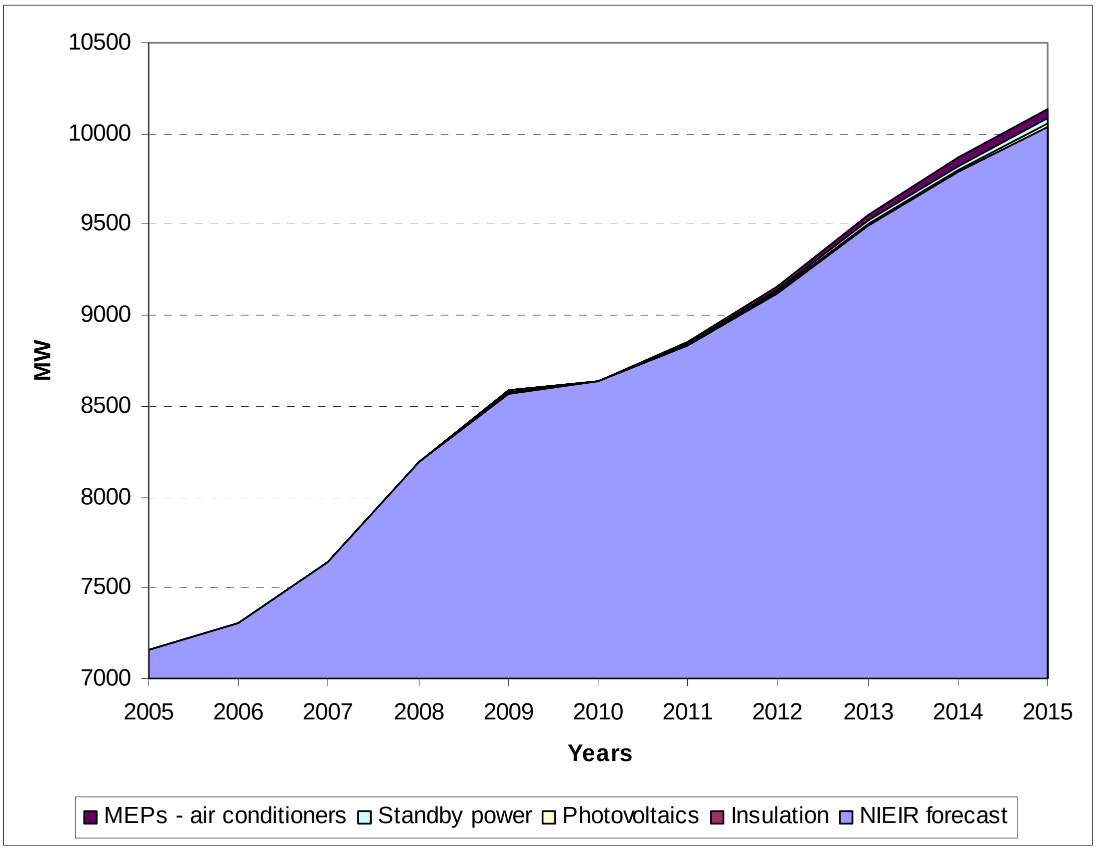
Table 5.13 NIEIR revised forecast cumulative policy adjustments (excluding AMI), energy consumption (GWh)

Policy (GWh distributed)	2011	2012	2013	2014	2015
MEPs lighting	–248	–373	–447	–472	–497
Standby power	–28	–84	–140	–178	–198
Insulation	–21	–21	–21	–21	–21
Photovoltaics	–14	–19	–23	–26	–28
VEET	–36	–54	–72	–95	–108
MEPs air conditioners	–11	–18	–27	–35	–42
6 star building standards	–10	–31	–54	–74	–94
Electric cars (off peak)	0	1	2	4	6
Total policy impacts	**–391**	**–707**	**–1053**	**–1296**	**–1433**

Source: NIEIR revised energy consumption reports tables 6.2 and 6.5; AER analysis.

Figures 5.5 and 5.6 illustrate the impact of the revised post-model policy adjustments (that is, excluding CPRS, hot water and AMI) on the overall forecasts.

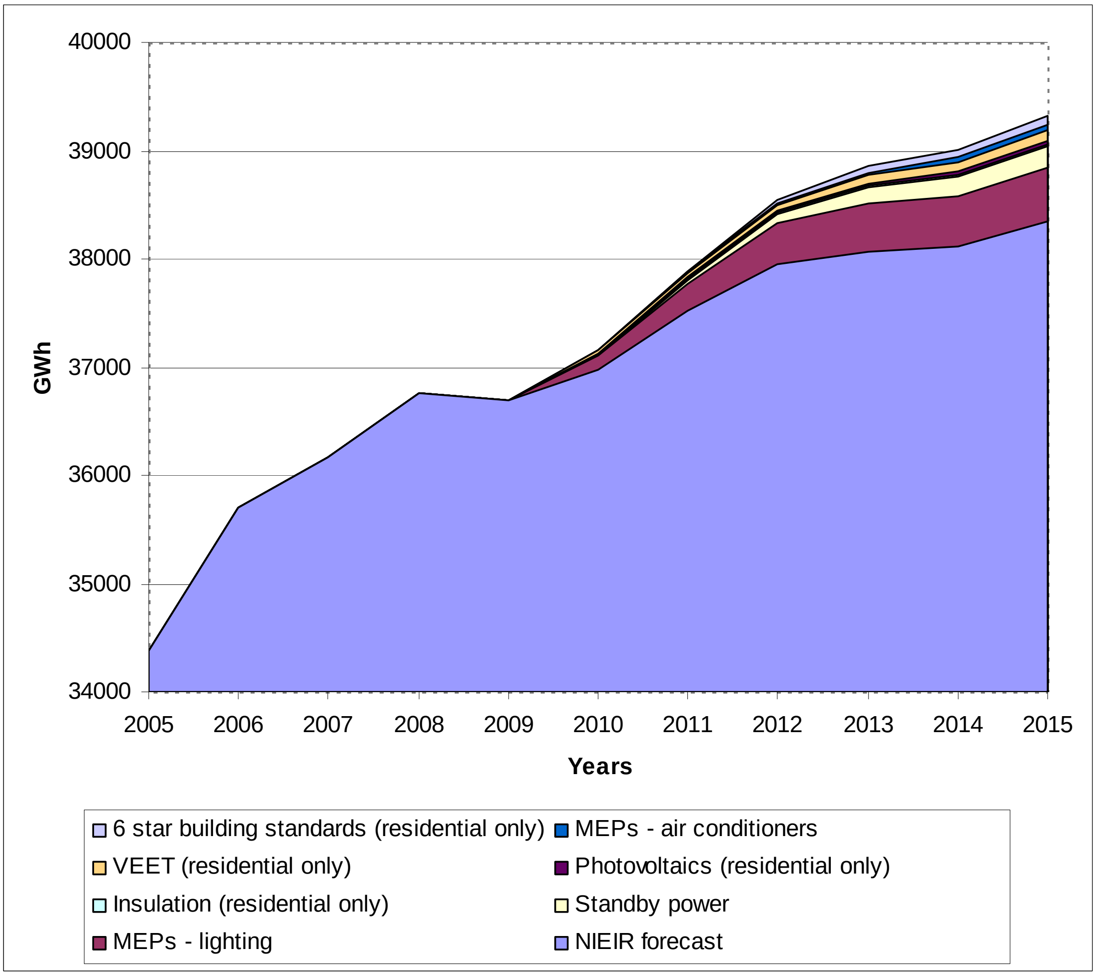
Figure 5.5 NIEIR's revised forecast cumulative policy adjustments (maximum demand)



Source: AER analysis, DNSP revised regulatory proposals and NIEIR revised maximum demand reports tables 6.3, 6.6, 10.4 and 10.6.

Note: The impact of the policies is to reduce NIEIR's "base" maximum demand forecasts.

Figure 5.6 NIEIR's revised forecast cumulative policy adjustments (energy consumption)



Source: AER analysis, DNSP revised regulatory proposals and NIEIR revised energy consumption reports tables 6.2 and 6.5.

Note: The impact of the policies is to reduce NIEIR's "base" energy consumption forecasts.

CitiPower, Powercor, JEN and United Energy commented on the draft decisions regarding NIEIR's post model adjustments, drawing on analysis prepared by consultants, other than NIEIR.

As noted above, CitiPower and Powercor engaged Frontier to review the policy adjustments made by NIEIR, as well as ACIL Tasman's recommended adjustments. JEN also attached the Frontier reports to its revised regulatory proposal, and reiterated Frontier's arguments. In its revised regulatory proposal, United Energy drew heavily on the report prepared by MJA, which was provided as a submission. The DNSPs made the following key arguments:

- MEPs for lighting—Citipower and Powercor rejected ACIL Tasman's analysis of NIEIR's post model adjustment, on the basis that it significantly underestimated the impact on energy consumption because it ignores the effect of MEPs on commercial lighting.[133] United Energy rejected ACIL Tasman's analysis on the basis that it is not possible to understand adequately how the RIS modelling, on which ACIL Tasman based its estimate, was derived.[134]

- One-watt standby target—the DNSPs referred the AER to the Ministerial Council for Energy's (MCE) National Standby Strategy (NSS) which includes a two stage process to improve the standby performance of electrical goods. JEN noted that it is reasonable to conclude from this strategy that standby targets will be met from 2012, and therefore the energy savings from this scheme should be accounted for.[135] United Energy also noted that the second stage of the process will involve MEPs applying from 2012 if voluntary action is inadequate, and therefore a reduction in standby energy use is expected in the forthcoming regulatory period.[136]

- Insulation rebate scheme—the DNSPs disagreed with the AER's draft decision that the post-model adjustments for energy savings from insulation should be removed as there was a rapid take-up of insulation under the program prior to its cancellation in April 2010. JEN noted that at least 30 per cent of uninsulated homes had already received insulation and therefore the updated NIEIR forecasts should be accepted.[137]

Frontier considered NIEIR's approach and estimates to be reasonable in most cases, however the following differences between NIEIR's and Frontier's conclusions are noted:

- MEPs for lighting—Frontier projected larger potential savings in the residential sector which is partly offset by lower projected savings in the commercial sector. The net effect is that while NIEIR's savings from MEPs for lighting are realised more quickly, Frontier forecast marginally greater savings by 2015.[138]

- VEET—Frontier projected larger overall savings which would be achieved more rapidly. This is due to differences between NIEIR's and Frontier's treatment of double counting and overlaps with other policies. Frontier compared the outcomes of VEET against MEPs for lighting, and considered that gains would be achieved more quickly under VEET and at a level that equates to 25 per cent of savings being additional to other programs.[139]

In addition to the Frontier reports, CitiPower and Powercor submitted a total of 120 publicly available documents relating to government policies on energy efficiency.[140] These documents outlined the details of each policy and their expected impact on energy consumption and maximum demand.

133 CitiPower, *Revised regulatory proposal,* July 2010, p. 101.
134 United Energy, *Revised regulatory proposal*, July 2010, p. 265.
135 JEN, *Revised regulatory proposal*, July 2010, p. 48.
136 United Energy, *Revised regulatory proposal,* July 2010, p. 266.
137 JEN, *Revised regulatory proposal*, July 2010, p. 49.
138 Frontier Economics, *Review of policy adjustments–a report prepared for CitiPower, July 2010,* pp. 27–42.
139 ibid., pp. 55–61.
140 CitiPower, *Revised regulatory proposal,* July 2010 - Additional evidentiary material in folder 56; Powercor , *Revised regulatory proposal,* July 2010 - Additional evidentiary material in folder 56.

5.6.4.3 Submissions

The Energy Users Association of Australia (EUAA) expressed concerns that the DNSPs had overstated the impact of policy measures designed to reduce energy consumption. The EUAA concluded that it would be imprudent for the AER to rely on the DNSPs' forecasts, as future policies are subject to considerable doubt and based on the impact of similar past policies. The EUAA also noted the inherent uncertainty surrounding the modelling used to support the introduction of the policies.[141]

The EUCV noted the DNSPs' assertions about reductions in consumption as a result of policy decisions, and considered the policies are not so much about reducing consumption as they are about load shifting and changes in fuels used for generation.[142]

CitiPower and Powercor submitted a further Frontier Economics report on the impact of the July 2010 Victorian Climate Change White Paper on energy forecasts. The report briefly assessed the likely impact on energy consumption of proposed policies, with regard to NIEIR's revised assumptions, in particular:

- Doubling of the VEET—Frontier commented that this policy may bring forward savings from other policies, however agreed with NIEIR's estimate that a minimum of 10 per cent of the savings from VEET be counted as additional to other policies.[143]

- 6-star minimum standard for new homes— Frontier agreed with NIEIR's estimate that energy savings from this policy were relatively small.[144]

- Extending the Victorian rebate scheme for solar hot water— Frontier noted that it was unlikely that this policy would have a material impact on the level of electricity use.[145]

- Energy efficiency target for Victorian Government buildings—Frontier noted that it did not have detailed information regarding Government electricity use in Victoria, but estimated from the data in the White Paper that a 20 per cent energy efficiency saving would equal 105GWh by 2018.[146]

Frontier noted that the other policies outlined in the White Paper were unlikely to have a large effect on energy consumption, particularly in the short-term.

United Energy submitted a report by MJA which calculated indicative savings estimates for Victoria for the forthcoming regulatory period from information in Regulatory Impact Statements (RIS) for each of the relevant energy efficiency policies. MJA stated that the RISs illustrate that governments explicitly intended their policies to have a material impact on energy consumption. MJA estimated that the cumulative impact of energy efficiency policies in Victoria over the 2010–2015

141 Energy Users Association of Australia (EUAA), *Submission to the AER*, August 2010, pp. 18–19.
142 Energy Users Coalition of Victoria (EUCV), *Submission to the AER*, August 2010, p. 63.
143 Frontier Economics, *Impact of the Victorian Climate Change White Paper on energy forecasts*, p. 7.
144 ibid., p. 9.
145 ibid., p. 10.
146 ibid.

period could be up to 16TWh. MJA further noted that policy changes foreshadowed for the forthcoming regulatory control period were intended to intensify the impacts of current energy efficiency policies in the future.[147]

MJA also considered the AER's amendment of NIEIR's post model adjustments for MEPs for lighting. MJA noted that the policy is intended to impact on all lighting used by households and businesses, and therefore the AER's draft decision is not reasonable as it disregards the impact on commercial lighting. In MJA's view, there was no clear basis for the AER to accept ACIL Tasman's recommendation over NIEIR's estimates, given the degree of simplification in ACIL Tasman's process to estimate the impact of MEPs for lighting in Victoria.[148]

5.6.4.4 Consultant review

After reviewing the information submitted by the DNSPs following the draft decision, ACIL Tasman made the following conclusions about NIEIR's post model adjustments:

- CPRS—NIEIR's assumption that the CPRS would commence in 2013 and follow a trajectory similar to the original CPRS–5 scenario was reasonable, with no further changes recommended.[149]
- MEPs for lighting—it did not consider NIEIR's revised estimate to be unreasonable.[150]
- MEPs for air conditioning—ACIL Tasman was unable to reach a view as to whether NIEIR's estimates were reasonable, however considered that the forecasted impact was not sufficiently large to warrant a more detailed analysis.[151]
- Insulation rebate scheme—ACIL Tasman noted its concerns with the estimates for this policy impact in the initial proposals were addressed, and did not recommend any further amendments to NIEIR's forecasted energy savings from this policy.[152]
- PV—ACIL Tasman regarded NIEIR's amendments regarding PV as reasonable.[153]
- Hot water initiatives—ACIL Tasman accepts that it is reasonable to make adjustments to account for the impact of this policy and considers NIEIR's approach reasonable.[154]
- VEET—ACIL Tasman considered NIEIR's forecasts had likely underestimated the impact of VEET, however considered the forecasts to be reasonable.[155]

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147 Marsden Jacob Associates, *AER Treatment of UED Energy Sales Volume Forecasts*, August 2010, p. 20–22.
148 ibid., p. 19–20
149 ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 16–17.
150 ibid., p. 33.
151 ibid., p. 40.
152 ibid., pp. 36–37.
153 ibid., pp. 37–38.
154 ibid., p. 20.
155 ibid., p. 38.

- 6 star building standards—ACIL Tasman did not recommend any adjustment to the forecasts of energy savings from this policy impact.[156]

- One-watt standby target— ACIL Tasman recommended that the estimated impacts of the one watt standby target should be disregarded and the growth forecasts adjusted by adding this impact back.[157]

ACIL Tasman also commented on the MJA report submitted by United Energy. It considered it reasonable to make post model adjustments for identified policy measures, however noted that it is not reasonable to make further adjustments for policies that were introduced over the 2006–2010 regulatory period as their effect is already reflected in electricity sales data.[158]

ACIL Tasman also considered the uncertainty surrounding a number of policies and noted that there is a chance that, new policies would be announced over the 5 year regulatory period, and therefore not be accounted for in the forecasts.

5.6.4.5 Issues and AER considerations

CPRS

The draft decision noted that the CPRS had been delayed following their initial regulatory proposals, and that the DNSPs should adjust their forecasts to account for this. In response, NIEIR revised its forecasts to account for the delay in the introduction of the CPRS, assuming that carbon pricing will commence in 2013 and will gradually be increased through to 2030, following a similar trajectory to the original CPRS-5 scenario outlined in the Australian Government Treasury's modelling.

There is still considerable uncertainty about the introduction of a carbon price in Australia. The AER agrees with ACIL Tasman that it is likely, but not certain, that either the CPRS or an alternative greenhouse emissions reduction policy would be introduced sometime during the next five years. The AER also agrees with ACIL Tasman that the methodology adopted by NIEIR, which is based on the Treasury CPRS-5 scenario, is reasonable. The AER accepts NIEIR's revised adjustments made to the energy and maximum demand forecasts to account for the impacts of the CPRS.

MEPs lighting

The AER's draft decision constrained NIEIR's forecast impacts of MEPs lighting on energy consumption to the impacts modelled in the RIS, as the AER and ACIL Tasman considered NIEIR's assumption that all incandescent lights would be replaced with compact fluorescent lamps (CFLs) over the forthcoming regulatory control period was unreasonable. The draft decision stated that NIEIR's estimate of the impact of MEPs lighting on maximum demand was reasonable.

In response, NIEIR revised its forecast MEPs lighting energy savings downwards, allowing for 30 per cent of households replacing incandescent lights with low voltage halogen (MEPs compliant) lights, instead of CFLs. Low voltage halogen lights are

[156] ibid., p. 41.
[157] ibid., p. 35.
[158] ibid., pp. 50–51.

only 30 per cent more efficient than incandescent lights, unlike CFLs which are 80 per cent more efficient. NIEIR's revised forecast suggested that household energy use will be reduced on average by 65 per cent due to the replacement of incandescent lights. NIEIR also included a rebound effect in lighting use which offset the implied savings by 10 per cent. Overall NIEIR's revised forecast represents a reduction in the assumed impact of the policy on energy of 15 per cent.

Frontier identified a number of limitations in the draft decision, in particular noting that ACIL Tasman did not include commercial energy savings in its estimated impact, despite the policy applying to both residential and commercial sectors.[159] MJA raised the same concerns with the draft decision on MEPs lighting, criticising what it saw as ACIL Tasman's simplified approach.[160]

ACIL Tasman referred to information NIEIR had provided to it which suggested that energy efficient lights were already in widespread use in the commercial sector and therefore that there were little energy savings to gain from the rollout of MEPs for lighting in the commercial sector. ACIL Tasman considered that energy saving behaviour had moved ahead of the policy to a greater extent even that NIEIR expected, largely due to activities under the VEET. After considering NIEIR's revised adjustments, ACIL Tasman concluded that NIEIR's estimated impact on energy consumption was not unreasonable.[161]

The AER has considered the information submitted by the DNSPs, and notes the degree of uncertainty relating to the future take up of energy efficient lighting, particularly given the success of the VEET scheme in encouraging the use of CFLs and the potential for market saturation. The emergence of low voltage halogen lights (which are MEPs compliant) has created another choice for consumers, and the differences between the electricity use of the two types creates further difficulty in forecasting the energy use from lighting over the next few years. Calculating the commercial take up of energy efficient lighting to date and the likely future impact of the VEET scheme as it is extended to commercial customers creates further difficulties.

Noting this uncertainty, the AER considers NIEIR's assumption that 30 per cent of households will replace incandescent lights with low voltage halogen lights rather than CFLs is not unreasonable.

MEPs air conditioning

The draft decision accepted NIEIR's estimated impact of MEPs air conditioning on energy and maximum demand forecasts. As noted in section 5.6.3, NIEIR updated the sales forecasts for air conditioning load to account for record air conditioner sales in 2009. This change slightly increased the assumed energy savings from MEPs.[162]

159 Frontier Economics, *Review of ACIL Tasman recommendations: A report for CitiPower*, July 2010, pp. 11–12.

160 Marsden Jacob Associates, *AER Treatment of UED Energy Sales Volume Forecasts*, August 2010, p.19–20.

161 ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 29–33.

162 NIEIR, *Electrical sales and customer number forecasts to 2019 for the JEN Electricity region*, June 2010, pp. 59–62.

ACIL Tasman did not have sufficient information from NIEIR regarding the way that it estimated the energy savings from MEPs for air conditioning, and therefore was unable to reach a view whether or not the estimate was reasonable. However, ACIL Tasman considered that the forecast impact is not sufficiently large to warrant a more detailed analysis, and did not recommend any changes to the forecasts. The AER agrees that NIEIR's estimated impact on the growth forecasts from MEPs air conditioning is immaterial, and considers that it is unlikely to be affect the overall reasonableness of the forecasts for the purposes of clauses 6.5.6(c)(3) and 6.5.7(c)(3).

Insulation rebate scheme

As the Australian Government's insulation scheme was cancelled in April 2010, the draft decision energy and maximum demand forecasts did not incorporate any impact of the policy. In response to the draft decision, the Victorian DNSPs, Frontier, MJA and NIEIR submitted that the effects of the insulation rebate scheme should not entirely be discounted given that around 30 per cent of uninsulated homes had already received insulation under the scheme prior to its cancellation.

Following the draft decision, NIEIR revised its estimated take-up rate from 50 per cent to 70 per cent of all uninsulated dwellings in light of the higher than anticipated take up rate of insulation in the first eight months of 2009–10. NIEIR's revised forecast allows for energy savings from the houses that had received insulation under the scheme prior to April 2010, and removes the forecast effects beyond 2010.

ACIL Tasman's initial report did not raise any concerns with the way in which the insulation impact was estimated by NIEIR. In its report on the DNSPs' revised regulatory proposal forecasts, ACIL Tasman considered NIEIR's assumptions regarding the impact of homes insulated in 2009 and 2010 was reasonable.[163]

The AER has considered the arguments for including the impact of the insulation rebate scheme in 2009 and 2010 on the underlying energy forecasts, and considers that it is reasonable to account for a one-off effect on energy consumption. This is particularly the case given the large number of homes that were insulated under the scheme prior to April 2010. Therefore the AER accepts NIEIR's estimate of this policy impact as reasonable.

Photovoltaics (PV)

Following comments in the draft decision that NIEIR has underestimated the number of solar panels installed in Victoria in 2009, NIEIR reviewed its assumed profile of energy savings from PV installations over the 2009–10 to 2011–12 period. NIEIR stated that it obtained actual data from the Office of the Renewable Energy and Department of Water Heritage and Arts to support ACIL Tasman's findings that it had underestimated installations in the 2008–09 period in its initial reports.[164]

As a result, NIEIR increased the total estimated impact of PV on energy consumption to 33GWh by 2019, and the impact on summer maximum demand by 18MW by 2019.

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163 ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 36–37.

164 See for example NIEIR, *Electrical sales and customer number forecasts to 2019 for the JEN Electricity region*, June 2010, pp. 65–66.

NIEIR stated that it considers this a conservative estimate, as any new policies to encourage PV take-up would only add to these savings.[165]

ACIL Tasman considered the revised impact on the forecasts to be reasonable, and noted the significance of the anticipated level of PV installation for the Victorian DNSPs.[166]

The AER has reviewed NIEIR's revised forecast, and agrees that the assumptions made in developing the calculated impacts are reasonable and consistent with the latest available data on PV in Victoria.

Electric Vehicles

Following comments in the draft decision that the scenario of electric vehicle take up assumed by NIEIR was unlikely, NIEIR downgraded its forecasts, finding that the penetration rate previously assumed was too high. NIEIR also noted that the outlook in this area is very uncertain given the competing technologies.[167]

ACIL Tasman did not comment on NIEIR's adjustments to its assumed impact of electric cars in its review of the revised regulatory proposal forecasts.[168]

The AER considers that the revisions NIEIR made have addressed ACIL Tasman's and the AER's concerns with the scenarios. The AER notes that ACIL Tasman's initial report, prior to the draft decision, considered that the impacts were too small to be considered material in the context of the other policy adjustments. [169] The AER maintains its draft decision that the adjustments made by NIEIR to account for electric vehicles are acceptable.

Hot Water initiatives

As noted above, the draft decision stated that the AER was unable to discern NIEIR's adjustments to the growth forecasts to account for hot water initiatives, and that the impacts listed in NIEIR's original reports were misleading.[170] ACIL Tasman raised a number of issues regarding its understanding of NIEIR's calculation of the hot water impacts, and pointed out that NIEIR's reported impact was substantially different (lower) to its own calculations of impacts based on data from DEWHA and Energy Consult for Sustainability Victoria.[171]

While the draft decision noted that the numbers reported in NIEIR's reports for hot water policies had no bearing on the actual demand forecast, the AER did not make any adjustment to NIEIR's energy or maximum demand forecasts in the draft decision to account for its concerns.[172]

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[165] ibid.

[166] ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 37–38.

[167] See for example NIEIR, *Electrical sales and customer number forecasts to 2019 for the JEN Electricity region*, June 2010, p. 75.

[168] ACIL Tasman, *Review of revised growth forecasts*, October 2010.

[169] ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of electricity sales and customer number forecasts, Report prepared for the AER*, 21 April 2010, p.57.

[170] AER, *Draft decision*, pp. 119–120.

[171] ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of electricity sales and customer number forecasts, Report prepared for the AER*, 21 April 2010, pp. 37–41.

[172] AER, *Draft decision*, June 2010, p. 120.

NIEIR's revised reports provided more information around its approach to calculating the impact of hot water polices on energy consumption, and explained the reasons why the impacts cannot be quantified within its core model. Frontier also reviewed NIEIR's initial and revised reports, and concluded that the figures produced in NIEIR's original reports (which NIEIR had previously advised were misleading) were reasonable estimates of the impact of the policy.

ACIL Tasman reviewed NIEIR's revised reports and Frontier's analysis, and was able to reconcile the substantial difference between its own calculations and NIEIR's assumptions by considering the fact that the major impact of hot water phase-out policies was already accounted for in NIEIR's trend forecasts. ACIL Tasman concluded that NIEIR's approach was not unreasonable.[173]

The AER notes that the difficulties it faced in ascertaining NIEIR's methodology and assumptions regarding the impact of hot water phase our policies prior to the draft decision appear to have been experienced by Frontier in its review of NIEIR's approach. While the AER agrees with ACIL Tasman's general conclusion that the assumed impact is not unreasonable (noting that the impact is of low materiality when considering the impact of other energy efficiency policies), the AER notes that NIEIR was unable to provide clear descriptions of its assumptions, which impacted on the AER's ability to properly assess the hot water policy assumption for the draft decision.

However, the AER considers that given ACIL Tasman's findings, NIEIR's estimated impact of hot water initiatives on the growth forecasts is unlikely to be unreasonable, and accordingly it is acceptable for the purposes of clauses 6.5.6(c)(3) and 6.5.7(c)(3).

Victorian Energy Efficiency Target (VEET)

NIEIR maintained its initial estimate that only 10 per cent of the potential savings from VEET would be additional to other government policies (that is given the overlap from other policies, for example MEPs lighting).[174] By contrast, Frontier Economics considered that 25 per cent of VEET activity will be additional.

ACIL Tasman noted the possibility that insulation would be reinstated as an eligible activity under VEET, as the Commonwealth insulation rebate scheme was cancelled. In light of this, ACIL Tasman considered it likely that NIEIR's estimate for VEET savings would be on the low side, however did not consider the forecast impact on energy consumption to be unreasonable.

The AER considers it reasonable to discount the potential savings from VEET to avoid double counting. The AER agrees with ACIL Tasman that if the VEET insulation target is reinstated, NIEIR's estimated savings from VEET may be understated. However this change is unlikely to have a material impact on energy consumption, and accordingly the AER considers NIEIR's estimated policy adjustment to account for the effects of VEET is acceptable.

173 ACIL Tasman, *Review of revised growth forecasts,* October 2010, p. 17–20.

174 See for example NIEIR, *Electrical sales and customer number forecasts to 2019 for the JEN Electricity region*, June 2010, p. 68–69.

6 star building standards

NIEIR revised downward its estimated savings in consumption resulting from the move to 6 star building standards, taking into consideration the potential rebound effects inherent in a more energy efficient home. NIEIR also noted that as homes get larger, the savings due to the new standard are likely to be smaller. The revised forecast assumes that savings in electricity will be 10 per cent per new dwelling.

NIEIR also considered that future peak electricity demands in the residential sector depend on trends in loads in peak periods (particularly for air conditioning) and efficiency improvements in equipment and materials used to provide energy services in peak periods. NIEIR concluded that the interaction of these two opposing trends will determine the peak demand impact of new energy performance standards.[175] NIEIR's revised forecasts estimate a small impact on maximum demand over the forthcoming regulatory period, as listed in table 5.7.

ACIL Tasman considered this policy measure to be limited to a very small portion of overall electricity sales as it is only relevant for newly constructed homes and major renovations. It also considered the trend for larger homes which, although they are more energy efficient, may be large enough to have increasing demand for electricity. Given that the forecast energy consumption savings are modest, ACIL Tasman did not recommended an adjustment to the forecast policy impact.[176]

The AER maintains its draft decision position that the portion of the overall demand forecasts that would be affected by the 6 star building policy would be modest, and unlikely to affect the overall reasonableness of the forecasts.

One watt standby target

The Victorian DNSPs and Frontier referred to the National Standby Strategy announced by the MCE in 2002 to provide evidence of policy action to meet a one-watt standby target for appliances. The Victorian DNSPs concluded that the standby targets would be met from 2012, as the second stage of the policy includes a mandatory target scheme where voluntary targets provide insufficient results.

NIEIR's revised forecasts assumed that there is sufficient evidence of policy action to meet one-watt standby targets for all electrical appliances and equipment by 2012. NIEIR considered that its initial forecasts underestimated the total impact of standby power on energy and maximum demand, and corrected its forecasts appropriately. As a result, the Victorian DNSPs' revised energy forecasts are slightly lower than the initial forecasts.

ACIL Tasman was less confident than the DNSPs, NIEIR and Frontier that a one-watt standby target will be mandated during the coming regulatory period. This is mainly because the National Partnership Agreement, signed on 2 July 2009 by COAG members, and the corresponding measures table, make no mention of standby power targets. Further, ACIL Tasman noted that all measures introduced under the National Partnership agreement will be subject to a RIS and to date, no RIS has been issued for standby targets. ACIL Tasman considered that if standby targets are to be introduced,

[175] See for example NIEIR, *Electrical sales and customer number forecasts to 2019 for the JEN Electricity region*, June 2010, p. 71.

[176] ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 40–41.

they would more likely be in the form of a series of individual MEPs for subsets of appliances.

ACIL Tasman accepted that there may be some reduction in the standby power requirements of household appliances over the coming regulatory period, however considered NIEIR's assumption that all household appliances will be required to draw no more than one watt in standby mode to be unduly optimistic. In light of these considerations, ACIL Tasman recommended that the estimated impacts of the one watt standby target on energy and maximum demand should be disregarded.

The AER agrees with the advice it received from ACIL Tasman that the assumption of a one-watt standby target for all household appliances is overly optimistic. The AER remains of the view that the Victorian DNSPs have not demonstrated sufficient evidence of a government policy to implement one watt standby targets for all household appliances. The AER considers it likely that customer behaviour has moved ahead of the 2002 National Standby Strategy, negating the need for the policy to be properly implemented via a mandatory target scheme.

As such, the AER considers that the underlying trend energy consumption in Victoria already reflects the move to one-watt standby, and to adjust the forecasts for the policy would be double-counting the impact. In light of this, the AER considers that the Victorian DNSPs' estimates of the impact of one watt standby power targets are not reasonable and that the growth forecasts should be adjusted by adding NIEIR's estimated impact back on.

5.6.4.6 AER conclusion

The AER reiterates comments made in the draft decision that there is a significant level of uncertainty around growth forecasts over the forthcoming regulatory control period regarding the potential impact of government energy efficiency policies. Despite this uncertainty, the AER has closely reviewed the assumptions within the DNSPs' forecasts, and agrees with the advice it has received from ACIL Tasman. The AER considers that policy adjustments made by NIEIR are acceptable, except for the adjustment to account for the one watt standby targets.

The AER considers that the Victorian DNSPs have not demonstrated sufficient evidence of a government policy to implement one watt standby targets. As such, the assumed impact of one watt standby on maximum demand means that the proposed forecasts do not reflect a realistic expectation of the demand forecast as required by clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER.

The AER considers that the assumed impact of one watt standby targets on energy consumption is unreasonable and results in energy forecasts that are not appropriate inputs into the AER's PTRM, as provided for in clause 6.12.1(10) of the NER. In accordance with clause 6.12.3(f), the AER has only amended the DNSPs' energy consumption forecasts to the extent necessary to enable it to be approved in accordance with the NER.

Tables 5.14 and 5.15 summarise the AER's adjustments to the Victorian DNSPs' forecasts arising from its considerations of policy impacts.

Table 5.14 AER forecast cumulative policy adjustments (excluding AMI), maximum demand (MW)

	2011	2012	2013	2014	2015
Total policy impacts—DNSPs (NIEIR)	–17.2	–37.9	–58.8	–77.6	–95.2
AER adjustment—standby power	3.4	10	16.6	23.2	29.8
Total policy impacts—AER decision	–13.8	–27.9	–42.2	–54.4	–65.4

Source: AER analysis; NIEIR revised maximum demand reports tables 6.3 and 6.6.

Table 5.15 AER forecast cumulative policy adjustments (excluding AMI), energy consumption (GWh)

	2011	2012	2013	2014	2015
Total policy impacts—DNSPs (NIEIR)	–391	–707	–1053	–1296	–1433
AER adjustment—standby power	28	84	140	178	198
Total policy impacts—AER decision	–363	–623	–913	–1118	–1235

Source: AER analysis; NIEIR revised energy consumption reports tables 6.2 and 6.5.

5.6.5 Spatial maximum demand forecasts

This section examines each DNSP's 'bottom up' maximum demand forecasts through a review of forecasts at selected ZSSs. The demand forecasts at this 'spatial' level of the network are a major driver of the capex requirements of each DNSP.

The spatial forecasts prepared by each DNSP involve the following general steps:

- individual forecasts for each ZSS are prepared, taking into account historic growth rates, weather, expected future growth, impacts of large new developments and load transfers
- these forecasts are aggregated together, taking account of diversity, to the terminal station level
- in most cases these are then compared to the terminal station forecasts prepared by NIEIR, with some adjustments made to ZSS forecasts as a result.

The AER as part of its review of maximum demand forecasts considered that a further detailed review of the DNSPs' maximum demand forecasts was required than had been undertaken prior to the draft decision. This being to ensure the reasonableness of the maximum demand forecasts that are driving the major augmentation projects proposed by each DNSP. This further analysis was supported by United Energy in its revised regulatory proposal where it acknowledged that it would be useful for the AER to gain an understanding of how the forecast and actual demand forecasts are derived for the key network components.[177]

[177] United Energy, *Revised regulatory proposal*, July 2010, p. 245.

The AER engaged ACIL Tasman to undertake a detailed analysis of a selected number of ZSSs that were driving the proposed major reinforcement projects being assessed by Nuttall Consulting and the AER as part of the capex review. The AER sought from each DNSP detailed information for selected ZSSs which included:

- basis of underlying growth prospects and economic drivers at each ZSS and how they were applied
- details of the major new loads expected to occur at each ZSS
- details of historical and forecast permanent load transfers
- daily time series data for each ZSS.

The approach adopted by ACIL Tasman in assessing the reasonableness of the maximum demand forecasts was to place significant weight on the recent history of demand at each ZSS and then seek to identify valid reasons for any divergence in the forecast growth rates at the specified ZSSs. This entailed:

- comparison of historical and forecast growth rates at each ZSS
- assessment of the demographic and physical characteristics of the area
- identify and account for major new block loads
- correction for any permanent transfers
- re-calculate and compare the historical and forecast growth rates after accounting for significant new loads
- determine whether the forecast growth rate is reasonable given past behaviour, system-level behaviour and future prospects for growth.[178]

The following section outlines the detailed assessment of maximum demand forecasts undertaken for the selected ZSSs for each DNSP.

5.6.5.1 CitiPower

In its response to the detailed information request, CitiPower stated that its growth rates are based on historical growth and there is no consideration of population projections factored into CitiPower's load forecasts.

CitiPower also provided a load forecast model which included historical block loads for the past five years. The load forecast model provided also showed the process for adding projected block loads and transfers to the forecast.

CitiPower in the information provided have forecast relatively few large block loads, with the exception of the Bouverie/Queensberry St ZSSs where a large blocks load is forecast from the Royal Children's Hospital in 2010 and 2011.

[178] ACIL Tasman, *An assessment of selected zone substation maximum demand forecasts*, September 2010, p. 2.

Table 5.16 outlines ACIL Tasman's assessment of CitiPower's nominated ZSSs.

Table 5.16 CitiPower - detailed ZSS review

Zone substation	Proposed augmentation	ACIL Tasman assessment
ZSS - Bouverie/Queensberry St	Additional transformer	Annualised growth is forecast at 3.7 per cent compared with the historical rate of 1.6 per cent growth. ACIL Tasman considered that this is consistent with system level forecast growth.
DA ZSS - Docks area	ZSS augmentation	Annualised growth in maximum demand is forecast at 8 per cent, compared with historical growth rate of 3.6 per cent. ACIL Tasman considered that there was not sufficient evidence to justify the proposed jump between 2010 and 2011. It considered the growth rate should be reduced to 2.1 MW per annum.
FR ZSS – Flinders/Ramsden	11 kV feeder works	ACIL Tasman considered forecast demand for at this ZSS to be reasonable.
JA ZSS – Little Bourke St	11 kV feeder works	ACIL Tasman considered that the increase in growth at this ZSS is not inconsistent with the general increase in growth rates for the sum of all non-coincident ZSSs. ACIL Tasman therefore considered the forecast to be reasonable.
MP ZSS – McIllwraith Place	11 kV feeder works	ACIL Tasman considered that the forecast growth rate is reasonable when compared with the historical rate.
VM ZSS – Victoria Market	11 kV feeder works	ACIL Tasman considered there to be an issue with the data for 2010 and has sought further clarification for this.
WA - Celestial Avenue	11 kV feeder works	ACIL Tasman considered that the forecast growth in maximum demand has not been justified. The forecast should be adjusted to the observed historical peak in 2007.

Source: ACIL Tasman, *Assessment of selected zone substation maximum demand forecasts*, September 2010.

AER considerations

The AER agreed with the assessment undertaken by ACIL Tasman and based on its own assessment it found that the high forecast growth at the Docks area ZSS had not been adequately justified by CitiPower. The AER therefore requested further detail from CitiPower to justify the high forecast growth in maximum demand. CitiPower's response noted that for the Docks area it receives a high number of load applications each year. These applications are factored into the load forecast as a weighted average load increase per year. 1.82MVA of the forecast new load connections per year are factored into the forecast to capture this trend.[179]

The AER considers that the jump in forecast growth in 2011 has not been justified and that it is reasonable to restrict the maximum demand forecast at the Docks area ZSS to increase by 2.1 MW per annum. The AER considers this to be reasonable and still allows for a forecast growth rate significantly higher than historical trends.

For Celestial Avenue the AER considers that based on the historical decline in maximum demand, the forecast growth rate has not been adequately justified by CitiPower. The AER therefore agrees with ACIL Tasman that the forecast maximum demand should be adjusted so that the maximum demand in 2015 reaches the observed historical maximum demand in 2007.

The AER also considers that the change in power factor has not been adequately explained by CitiPower. This concern was queried with CitiPower by the AER, and in its response CitiPower provided revised maximum demand forecasts that included revised forecasts which reflected power factors more consistent with the historical trend.[180] The AER is therefore satisfied that no further adjustment is required based on the power factor.

5.6.5.2 Powercor

In its response to the detailed information request for the selected ZSSs, Powercor provided a description of the basis of the growth for the nominated ZSS. It stated that for Cobram East ZSS it had applied a growth of 2.6 per cent per annum over the next 10 years. This growth rate is derived from historical growth rates for each distribution feeder supplied by Cobram East ZSS, estimated population growth due to Moira Shire's strategy to open up new residential areas in Cobram and Yarrawonga, and likely changes to customer behaviours.[181]

For the Eaglehawk ZSS Powercor had projected a growth rate of 2.6 per cent per annum. Powercor stated this rate is based on historical growth rates for each feeder, likely changes in demographics due to the opening up of new residential areas and likely changes to customer behaviour, including the increased penetration of reverse cycle air-conditioners, known new customer loads and load transfers to or from feeders adjoining ZSSs.[182]

For the Woodend ZSS Powercor applied a growth rate of 3.9 per cent over the next 10 years. This is a significant increase from historical growth rate of 1.53 per cent. Powercor considers this is due to likely changes in demographics due to re-zoning of land for new residential, commercial and industrial areas and likely changes to customer behaviours. [183]

Table 5.17 outlines ACIL Tasman's assessment of the additional information on the following ZSS.

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[179] CitiPower, *Response to information requested 9 September*, 17 September 2010.
[180] CitiPower, *Response to information requested 9 September*, 17 September 2010.
[181] Powercor, *Response to information requested 5 August 2010*, 24 August 2010.
[182] Powercor, *Response to information requested 5 August 2010*, 24 August 2010.
[183] Powercor, *Response to information requested 5 August 2010*, 24 August 2010.

Table 5.17 Powercor - detailed ZSS review

Zone substation	Proposed augmentation	ACIL detailed zone substation review
CBE - Cobram East	NKA-CBE line upgrade	It is not unreasonable for overall demand growth to approach 4 to 5 per cent per annum. ACIL Tasman therefore considered the proposed forecast to be reasonable.
EHK - Eaglehawk	Additional transformer	Demand growth is forecast increase from 2.9 per cent to 4.9 per cent from 2010 to 2015, after adjusting for block loads.
GLE - Geelong East	Transformer upgrade	The historical growth rate over the five year period to 2010 was 5.0 per cent, where the forecast growth rate is 1 per cent per annum. Forecast is therefore considered reasonable.
WND - Woodend	New ZSS at Gisbourne	Has had an annualised growth rate of 1.3 per cent per annum. Forecast growth rate from 2010 to 2015 to increase to 4.2 per cent per annum. This being due to rezoning for residential, commercial and industrial use in Gisborne.
WPD - Waurn Ponds	New ZSS at Torquay	Forecast growth has increased from 3.4 per cent from 2005–2010 to 8.2 per cent from 2010–2015. This has been explained by the significant block loads from new residential developments. After adjusting for these loads the growth matches the historical levels. ACIL Tasman therefore considered the forecast to be reasonable.

Source: ACIL Tasman, *Assessment of selected zone substation maximum demand forecasts*, September 2010.

AER considerations

The AER considers that Powercor has forecast significant growth in its maximum demand forecasts for the nominated ZSSs, including at Eaglehawk, Woodend and Waurn Ponds. The AER notes that Powercor considered these growth rates are justified based on the expected growth in residential and commercial development occurring in these areas. The high forecast growth rates were queried with Powercor.

Powercor in its response noted that at the Eaglehawk ZSS the load forecast is based on historical data over a minimum of ten years, where basing future load growth forecasts on the past five years leads to incorrect forecasting as loads vary from the long term growth rate. It also noted that the forecast load growth from 2011–2015 is 4.38 per cent, which very close to the average load growth from 2005–2015 of 4.68 per cent.[184]

For the Woodend ZSS, Powercor submitted that there has been steady growth in commercial, industrial and residential load, and is affected by the growth in population in Melbourne flowing out to regional areas.[185]

[184] Powercor, *Response to information requested 9 September 2010*, 17 September 2010.
[185] Powercor, *Response to information requested 9 September 2010*, 17 September 2010.

The AER considers that ACIL Tasman has undertaken a thorough review of the nominated ZSSs that are driving some major augmentation projects proposed by Powercor and agrees that based on its assessment.

The AER is therefore satisfied that based on the detailed ZSS review that Powercor's maximum demand forecasts are reasonable.

5.6.5.3 Jemena Electricity Networks (JEN)

In response to the additional information requested on the selected ZSSs, JEN stated that forecast organic growth rates are based on those of previous years, derived at the end of the previous year's reconciliation process. JEN also noted that it had provided additional information on its load forecast methodology in appendix 5.10 of its revised regulatory proposal.

ACIL Tasman noted in its review that JEN's network contains both fast and slow growing regions in terms of population growth. Based on the information provided, ACIL Tasman noted that JEN has forecast comparatively few transfers over the next regulatory period for the nominated ZSSs. Table 5.18 outlines ACIL Tasman's review of JEN's maximum demand forecasts for the selected ZSSs.

Table 5.18 JEN - detailed ZSS review

Zone substation	Proposed augmentation	ACIL Tasman assessment
Zone Substation 3 (AW) - Airport West	New ZSS at Tullamarine	ACIL Tasman considered that the forecast is reasonable and is comparable with historical levels.
Zone Substation 4 (BD) - Broadmeadows	Broadmeadows South ZSS	The rate of growth is forecast to be 0.3 per cent per annum compared with the historical rate of 3.1 per cent per annum and therefore is reasonable.
Zone Substation 9 (COO) - Coburg South	Additional transformer	The forecast growth rate of maximum demand is consistent with historical levels and is therefore reasonable.
Zone Substation 15 (FT) - Flemington	Additional transformer	The forecast growth rate is consistent with historical levels and is therefore reasonable.
Zone Substation 24 (PV) - Pascoe Vale	ZSS upgrade	Forecast growth rates are much lower than historical growth rates. Therefore the forecast was considered reasonable.

Source: ACIL Tasman, *Assessment of selected zone substation maximum demand forecasts*, September 2010.

AER considerations

The AER considers that ACIL Tasman has undertaken a thorough review of the nominated ZSSs that are driving some major augmentation projects proposed by JEN. Based on ACIL Tasman's assessment and the AER's assessment of the information provided by JEN, the AER considers that the forecast growth rates in maximum demand at the nominated ZSSs are reasonably consistent with historical growth rates or divergences have been adequately explained. The AER is therefore satisfied that based on the detailed ZSS review that no further adjustment is required to JEN's maximum demand forecasts.

5.6.5.4 SP AusNet

SP AusNet in its response to the information request provided a qualitative discussion of the basis for growth at the nominated ZSSs and provided detail on how growth rates are applied to the forecast. Based on the information provided by SP AusNet it calculates an average growth rate based on demand from historical data the previous year's forecast as a starting point, and then adds forecast load transfers and forecast block loads.[186]

Regarding major block loads SP AusNet stated in its revised regulatory proposal that it avoids block loads in generating its forecasts, except where it deems them to be significant. This is to avoid the possibility of double counting. The only additional block load for the nominated ZSSs is 5 MW at Epping in 2013 for the relocation of the Footscray fruit and vegetable market to Epping.[187]

Table 5.19 outlines ACIL Tasman's review of SP AusNet's maximum demand forecasts for the nominated ZSSs.

[186] SP AusNet, *Response to information requested 5 August 2010*, 13 August 2010.
[187] SP AusNet, *Response to information requested 5 August 2010*, 13 August 2010.

Table 5.19 SP AusNet - detailed ZSS review

ZSS	Proposed augmentation	ACIL Tasman assessment
Clyde North	Third transformer	On the basis of observed historical demands and demographic knowledge of the area ACIL Tasman considered the forecast to be reasonable.
Croydon	Mooroolbark ZSS	The growth rate is consistent with low growth forecast in the area and is therefore considered reasonable.
Epping	New ZSS at Wollert	Forecast growth rates are lower than has occurred historically therefore ACIL Tasman considered the maximum demand forecast to be reasonable.
Ferntree Gully	Third transformer	The annualised historical growth rate was 9 per cent per annum and the forecast growth rate is 3.7 per cent per annum. ACIL Tasman considered that the growth rate is reasonable given that it is becoming a more established area with fewer large developments.
Kilmore South	Third transformer	ACIL Tasman has accepted that SP AusNet's slower than historical growth in its forecast is reasonable.
Lilydale	Mooroolbark ZSS	Forecast annualised growth is forecast at 7.7 per cent compared with a historical growth of 8.2 per cent per annum. ACIL Tasman considered this to be reasonable given that Lilydale is on the outskirts of Melbourne and has further potential for growth.
Moe	Third transformer	ACIL Tasman considered that the forecast annualised growth rate for Moe had increased by from 6.5 per cent from a historical rate of 5.5 per cent.
Ringwood North	Mooroolbark ZSS -	Annualised growth has been forecast at 4.6 per cent, compared with a historical average of 7.2 per cent. ACIL Tasman considered that based on this ZSS being located in a medium growth area that the forecast is reasonable.
Woori Yallock	Mooroolbark ZSS	Annualised growth has been forecast at 1.1 per cent, compared with a historical average of 4 per cent. ACIL Tasman accepted this growth rate as reasonable.

Source: ACIL Tasman, *Assessment of selected zone substation maximum demand forecasts*, September 2010.

AER considerations

The AER considers that ACIL Tasman has undertaken a thorough review of the nominated ZSSs that are driving some key major augmentation projects proposed by SP AusNet. The AER agrees that based on the assessment of the nominated ZSSs that the growth rates applied to the maximum demand forecasts are consistent with historical trend and the expected growth rates in the relevant areas.

The high growth rate at Moe ZSS found by ACIL Tasman was followed up with SP AusNet. In its response, SP AusNet considered that the growth rate for 2005–2009 gives a growth rate of 7.6 per cent, which underpinned the forecast growth rate of 6.5 per cent. The maximum demand for 2010 was lower than forecast and this has reduced the historical growth rate and made the forecast growth rate of 6.5 per cent look higher than the historical average.[188] The AER therefore considers that the growth rate be adjusted consistent with historical trend.

The AER is therefore satisfied that based on the detailed ZSS review that no further adjustment is required to SP AusNet's maximum demand forecasts, aside from an adjustment to maximum demand forecast at the Moe ZSS.

5.6.5.5 United Energy

United Energy provided further detailed information on the selected ZSSs. It noted that previous years organic growth rates are generally used as the starting growth rates in the iteration process of forecasting. United Energy noted that these are sometimes adjusted based on judgement on a by exception basis if there are changes in large customer demands.[189] Table 5.20 outlines ACIL Tasman's review of maximum demand for the ZSSs for United Energy.

[188] SP AusNet, *Response to information requested 9 September 2010*, 15 September 2010.
[189] United Energy, *Response to information requested 5 August 2010*, 19 August 2010, p. 3.

Table 5.20 United Energy - ACIL Tasman detailed ZSS review

Zone substation	Proposed augmentation	ACIL Tasman assessment
Doncaster	Templestowe ZSS	ACIL Tasman considered that the forecast annualised growth rate was consistent with historical levels and the mature nature of the area.
Dandenong South	Keysborough ZSS	ACIL Tasman noted that forecast annualised growth is 2.7 per cent compared with 1.8 per cent after adjusting for block loads. ACIL Tasman considered this to be likely due to expected economic recovery from 2011 onwards compared with the sluggish growth between 2008 and 2010.
Mentone	Additional transformer	Forecast annualised growth is equal to 0.7 per cent compared with the 1.6 per cent historically. ACIL Tasman considered this growth rate to be reasonable.
Noble Park	Keysborough ZSS	Annualised growth is forecast to be 1.7 per cent, compared with an historical growth rate of 3.8 per cent. ACIL Tasman considered that the forecast growth rate is broadly consistent with the slower growth profile of the area and the United Energy network.

Source: ACIL Tasman, *Assessment of selected zone substation maximum demand forecasts*, September 2010.

AER considerations

The AER considers that ACIL Tasman has undertaken a thorough review of the nominated ZSSs that are driving some major augmentation projects proposed by United Energy. Based on ACIL Tasman's assessment and the AER's assessment of the information provided by United Energy, the AER considers that the forecast growth rates in maximum demand at the nominated ZSSs are reasonably consistent with historical growth rates, and where divergences have occurred they have been adequately explained. The AER is therefore satisfied that based on the detailed ZSS review that no further adjustment is necessary to United Energy's maximum demand forecasts.

5.6.5.6 AER conclusions - review of ZSS forecasts

Based on a detailed ZSS review, the AER is satisfied that overall each DNSP's proposed maximum demand forecasts are consistent with historical trend and where increases in historical growth have occurred they have been adequately explained. The exceptions to this are the maximum demand forecasts for the Docks area and Celestial Avenue ZSSs for CitiPower, and Moe ZSS for SP AusNet. These adjustments have been factored into the AER's reinforcement capex assessment (see appendix P).

The AER considers that based on its assessment of the revised regulatory proposals, with the exceptions of the ZSSs outlined above, the maximum demand forecasts proposed by CitiPower, Powercor, JEN, SP AusNet and United Energy at the ZSS level are reasonable and reflect a realistic expectation of the demand forecasts required to achieve the capex and opex objectives, as required in clauses 6.5.7(c)(3); 6.5.7(a)(1); 6.5.6(c)(3) and 6.5.6(a)(1) of the NER.

5.6.6 Reconciliation of spatial and system wide forecasts

As noted previously, one major shortcoming in the DNSPs' forecasts highlighted by the AER and ACIL Tasman was the lack of reconciliation between independently generated top-down (network level) forecasts and network planner produced bottom up forecasts. As a result of this, the AER considered that the DNSPs' forecasts did not properly account for economic growth and the impact of government policies. The AER also noted the lack of transparency and repeatability in the methods applied by most DNSPs.

For the draft decision, the AER used data submitted by each DNSP on the historical diversity between network and ZSS level maximum demands to carry out reconciliation to the DNSPs' top down forecasts, as recommended by ACIL Tasman. The reconciliation was used to calculate a total required reduction in each DNSPs' summed ZSS maximum demand forecast, which was then allocated among a selected number of ZSS. This reconciliation also incorporated the AER's adjustments to the top down forecasts as a result of policy impacts.[190]

The AER's draft decision maximum forecasts for the Victorian DNSPs are provided in table 5.21.

Table 5.21 Draft decision conclusions on maximum demand forecasts—sum of non-coincident ZSSs (MW)

	2011	2012	2013	2014	2015
CitiPower	1 465	1 509	1 573	1 603	1 627
Powercor[(a)]	2 327	2 437	2 569	2 669	2 747
JEN	1 067	1 096	1 134	1 168	1 184
SP AusNet	1 858	1 928	2 032	2 125	2 212
United Energy	2 266	2 352	2 406	2 509	2 558

(a) Sum of coincident ZSSs.

Given the business specific nature of the spatial forecasts, the following sections outline each DNSP's revised regulatory proposal, ACIL Tasman's assessment and the AER's considerations for each DNSP in turn.

[190] The draft decision zone substation forecasts were produced in AER, *Draft decision*, pp. 134–142.

5.6.6.2 CitiPower & Powercor

Revised regulatory proposals

CitiPower and Powercor did not accept the AER's draft decision that their spatial maximum demand forecasts are likely to overstate maximum demand in 2011-15.[191]

CitiPower and Powercor argued that the peak demand forecasts relied on by the AER for the purposes of its analysis were incorrectly cited and should be the sum of feeder peak demands. CitiPower also considered that the AER did not consider the significant diversity between feeder maximum demand and system maximum demand.[192]

CitiPower and Powercor also considered that the AER and ACIL Tasman placed undue reliance on NIEIR's November 2009 forecast, which contained errors. CitiPower also considered that raw coincidence factors cannot be used as a reliable estimate for either individual non-coincident ZSS maximum demand or summated ZSS non-coincident maximum demand.

CitiPower and Powercor stated they have conducted a top down reconciliation of their internal spatial demand forecasts and that the AER should be satisfied that NIEIR's maximum demand forecasting methodology is reasonable.

CitiPower and Powercor reconciled the system level NIEIR maximum demand forecasts by reference to Sinclair Knight Mertz' s (SKM) expert report on their maximum demand forecasts. This report assessed whether a reasonably reliable ratio can be established between the 50 per cent PoE historical non-coincident ZSS maximum demands and CitiPower's and Powercor's network maximum demand. It then tested whether this ratio is within a 90 per cent confidence level.[193]

CitiPower and Powercor noted in their revised regulatory proposals that their spatial forecasts and the NIEIR system level forecasts are consistent with the 90 per cent confidence interval determined by SKM.[194]Therefore they considered that the sum of the non-coincident ZSSs maximum demand forecasts reasonably reconcile with the system level forecasts.

CitiPower also adjusted forecast maximum demand due to actual data from 2010 was driven by four ZSSs in the Fisherman's Bend precinct being lower then anticipated.[195]

Consultant review

ACIL Tasman's view is that the use of SKM's confidence interval in this analysis is a flawed application of statistical techniques. The main reason for this is that just because an observation falls within a confidence interval does not make that observation likely. Rather, the further an observation is from the mean, the less likely it becomes. Therefore, SKM's analysis appears to suggest that CitiPower's initial estimates for the last three years of the regulatory period were in fact very unlikely to

191 CitiPower, *Revised regulatory proposal*, July 2010, p. 111.
192 ibid.
193 ibid., p. 117.
194 CitiPower, *Revised regulatory proposal*, July 2010, p. 117; Powercor, *Revised regulatory proposal*, July 2010, p. 110.
195 CitiPower, *Revised regulatory proposal*, July 2010, p. 112.

be accurate. In addition, the inference testing assumes that the underlying data is normally distributed, and there is enough data to rely on the central limit theorem. However ACIL Tasman considered there is not enough observations to rely on this and from visual inspection that it indicates a downward trend for the first five years and then stabilises.[196]

For these reasons, ACIL Tasman does not consider that the confidence interval approach is an improvement on its preferred approach that the spatial forecasts should be reconciled to the system level forecasts and the diversity between system and spatial level forecast should reflect recent history.[197]

However based on its assessment of CitiPower's spatial forecasts, that to bring them into line with the historical mean diversity is no greater than half of one per cent, ACIL Tasman does not consider it necessary to make further revisions other than to account for policy impacts.[198]

ACIL Tasman compared Powercor's forecasts with the historic mean diversity between system and ZSS level demand. It found that the forecast diversity is consistent with historical levels and therefore does not consider it necessary to make further revisions to Powercor's forecasts other than to account for the policy impacts.[199]

AER considerations

The AER agrees with the assessment undertaken by ACIL Tasman that CitiPower's and Powercor's revised regulatory proposal non-coincident maximum demand forecasts now reasonably reconcile with the NIEIR system level forecasts. The AER therefore has not made any adjustment to CitiPower's and Powercor's revised regulatory proposal maximum demand forecasts in relation to reconciling them with the NIEIR system level forecast.

5.6.6.3 Jemena Electricity Networks (JEN)

Revised regulatory proposal

JEN agreed with the AER that the diversity factor between ZSS and network level maximum demand should not be diverging from its historical value. It noted that the average diversity factor used by ACIL Tasman in its report prior to the draft decision was based on historic maximum demand that had not been weather corrected.[200]

JEN stated that it carried out a full reconciliation of its bottom up forecast of ZSS coincident and non-coincident maximum demand with NIEIR's system level forecast and demonstrated that the diversity factor is fairly constant. This reconciliation is documented in appendix 5.9 of JEN's revised regulatory proposal.[201]

JEN has also accepted the revised NIEIR maximum demand forecast without adjustment. The revised NIEIR maximum demand forecast is higher than the

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196 ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 61.
197 ibid.
198 ibid., p. 64.
199 ibid., p. 87.
200 JEN, *Revised regulatory proposal*, July 2010, p. 53.
201 ibid., p. 53.

November 2009 forecast due to a revised forecast of air-conditioning installations, and the recognition by NIEIR of the distribution outages in January 2009. As a result JEN submitted that there is minimal change to its forecast ZSS non-coincident maximum demand forecast in November 2009.[202]

JEN stated that the ratio of summed ZSS non-coincident demand to NIEIR's system level demand is:

- 1.114 for the period 2006–2010
- 1.109 for the forecast period, 2011–2015.

Consultant review

In its assessment of the JEN's revised regulatory proposal forecasts, ACIL Tasman retained the view that JEN's maximum demand forecasts should be adjusted so that the ratio between the system level forecast and the sum of the ZSSs should not change over time. ACIL Tasman considered that to hold the ratio between JEN's ZSS and system level forecasts constant at the five year mean level, an adjustment to ZSS demand forecast would be required of between 0.2 and 0.6 per cent each year. Given that these adjustments are reasonably immaterial, ACIL Tasman considered that JEN's ZSS maximum demand forecasts do not require further adjustment other than to account for policy impacts.[203]

AER considerations

The AER agrees with the conclusion made by ACIL Tasman that JEN's revised regulatory proposal non-coincident maximum demand forecasts now reasonably reconcile with the NIEIR system level forecasts. The AER therefore has not made any adjustment to JEN's maximum demand forecasts as it considers they reconcile with the NIEIR system level forecast.

5.6.6.4 SP AusNet

Revised regulatory proposal

SP AusNet in its revised regulatory proposal noted that while it has adopted ACIL Tasman's recommended 4.4 per cent diversity between NIEIR's system level maximum and SP AusNet's ZSS non-coincident maximum demands, it did not accept the methodology used by ACIL Tasman in its original report prior to the draft decision. In particular, SP AusNet noted that the resulting downward adjustment is likely to significantly overstate the diversity factor.[204]

In relation to the allocation of reductions in demand across ZSSs, SP AusNet considered that the AER did not provide substantive evidence in support of why or how its decision would facilitate the development of capex programs that are consistent with the NER capex objectives, and that it is clear that the AER's process was arbitrary.[205]

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202 JEN, *Revised regulatory proposal*, July 2010, p. 53.
203 ACIL Tasman, *Review of revised growth forecasts,* October 2010, pp.76–78.
204 SP AusNet, *Revised regulatory proposal*, July 2010, p. 62.
205 ibid., p. 63.

SP AusNet contended a better alternative is to use the demand forecasts by NIEIR at the terminal station level to guide the breakdown of the AER's adjustment. More specifically, SP AusNet noted that the NIEIR forecasts represent an independent view of the spatial demand forecasts at a terminal station level. SP AusNet also considered that an arbitrary reduction imposed on demand forecasts at the ZSS level must have regard to the economic costs and risks associated with higher utilisation in high growth areas. Any arbitrary allocation should be focussed on lower growth areas where the economic costs and risk of getting the forecast wrong are lower.[206]

Therefore SP AusNet considered that utilising NIEIR's terminal station forecasts to make the required adjustments at the ZSS level is the most appropriate method. SP AusNet also stated that it constrained every ZSS forecast such that the ZSSs supplied from each terminal station did not exceed the terminal station forecast.[207]

Consultant review

ACIL Tasman's assessment found that SP AusNet's revised spatial forecasts converge on NIEIR's system forecast less than was originally the case. ACIL Tasman also found that the diversity ratio in SP AusNet’s region was lower in the past two years than over the past five years. However, based on its detailed assessment, ACIL Tasman considered SP AusNet's spatial maximum demand forecasts reasonably reconcile with the NIEIR system forecast and would only required a relatively small change, which is not warranted.[208]

AER Considerations

The AER agrees with the assessment undertaken by ACIL Tasman that SP AusNet's revised regulatory proposal non-coincident maximum demand forecasts reasonably reconcile with the NIEIR system level forecasts. The AER therefore has not made any adjustment to SP AusNet's revised regulatory proposal maximum demand forecasts in relation to reconciling them with the NIEIR system level forecast.

5.6.6.5 United Energy

Revised regulatory proposal

United Energy's revised regulatory proposal included a description of the way in which NIEIR's forecasts are generally incorporated into its business planning processes.[209] United Energy set out the reasons why it does not simply adopt NIEIR's forecasts, being that the disaggregation of NIEIR's forecasts into local government areas means that the forecasts do not correspond exactly to United Energy's network area. As such, United Energy carries out 'testing and feedback' processes, checking NIEIR's forecasts against historical forecasts and bottom up planning information.[210]

Regarding its reconciliation process, United Energy noted that its forecasting process starts with ZSS feeder load changes based on new/changed loads and an assumed organic growth rate for existing loads. The feeder load changes are then aggregated to form terminal station load growth. Finally the system forecast is obtained by the

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206 ibid.
207 ibid., p. 64.
208 ACIL Tasman, *Review of revised growth forecasts,* October 2010, pp. 96–99.
209 United Energy, *Revised regulatory proposal*, July 2010, pp. 241–242.
210 ibid., p. 242.

aggregate ZSS non-coincident maximum demand based on the historic diversity factor.[211]

The bottom up system forecast is then compared with the system forecast provided by NIEIR. Adjustment to the bottom up forecasts are made at the underlying organic growth rates of the feeders and ZSSs to ensure bottom up forecast reconciles to the NIEIR system level maximum demand forecast.[212]

While United Energy's load forecasting methodology does use a single diversity factor to aggregate ZSS non-coincident maximum demand, United Energy demonstrated that the ratio of (sum of) ZSS non-coincident demand to the NIEIR system demand averages 1.050 for 2011–15, where as the historic ratio is 1.051. Therefore, United Energy argued that there is no divergence from the historical diversity ratio in its revised regulatory proposal maximum demand forecasts.[213]

Consultant review

ACIL Tasman found that United Energy's revised maximum demand forecasts demonstrated that United Energy had undertaken a reasonable reconciliation between the NIEIR system level forecast and the ZSS forecasts. ACIL Tasman also found that when compared to the last five years, the ratio between United Energy's system and spatial forecasts is consistently very close to the mean. ACIL Tasman therefore did not recommend any adjustment to United Energy's non-coincident maximum demand forecasts.[214]

AER Considerations

The AER agrees with the assessment undertaken by ACIL Tasman that United Energy's revised regulatory proposal spatial maximum demand forecasts reasonably reconcile with the NIEIR system level forecasts. The AER therefore has not made any adjustment to United Energy's maximum demand forecasts as it is satisfied that they reconcile with NIEIR's system level forecasts.

5.6.6.6 AER conclusion

The AER is satisfied that based on its assessment of the revised regulatory proposals, each DNSP's proposed forecast of spatial non-coincident maximum demand adequately reconciles with the NIEIR system level forecast.

Notwithstanding its conclusion in section 5.6.5.6 in relation to CitiPower's and SP AusNet's maximum demand forecasts for selected ZSS, the AER considers that based on its assessment of the revised regulatory proposals, overall the maximum demand forecasts proposed by CitiPower, Powercor, JEN, SP AusNet and United Energy at the ZSS level are reasonable and reflect a realistic expectation of the demand forecasts required to achieve the capex and opex objectives, as required in clauses 6.5.7(c)(3); 6.5.7(a)(1); 6.5.6(c)(3) and 6.5.6(a)(1) and of the NER.

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211 United Energy, *Reconciliation of UED substation demand forecasts with NIEIR*, July 2010, p. 2.
212 ibid.
213 ibid.
214 ACIL Tasman, *Review of revised growth forecasts*, October 2010, pp. 96–99.

5.6.7 TOU tariff impacts

5.6.7.1 AER draft decision

Energy and maximum demand forecasts approved in the AER's draft decision did not incorporate the impact of time of use (TOU) tariffs, despite this being a post model adjustment made to the Victorian DNSPs' initial proposed energy forecasts. The draft decision outlined the following reasons for removing the impact of TOU tariffs from the forecasts:

- There is a limited amount of relevant information on TOU trial outcomes which the AER considers could be relied on to reasonably forecast a Victorian customer response to TOU tariffs within the forthcoming regulatory control period. The studies quoted by NIEIR and SP AusNet in their initial regulatory proposals do not reflect their choices of elasticities and energy or demand reductions. In addition, the assumptions made by the DNSPs and NIEIR about energy and maximum demand outcomes of TOU tariffs are inconsistent.

- There are a number of impediments to Victorian customers' abilities to respond to TOU tariffs in the short term, including retail price barriers and customer appliance stocks, which were not given sufficient weight in NIEIR's and the Victorian DNSPs' forecasts. With regards to long term effects, ACIL Tasman noted a 'rebound effect' where customers potentially become less responsive to TOU over time as they adjust to the new prices.

- On 22 March 2010, between the DNSPs' submitting their initial forecasts and the AER's draft decision, the Victorian Government announced a moratorium on the use of TOU tariffs. The AER considered that the moratorium placed a high degree of uncertainty on any assumed impact of the tariffs on energy and maximum demand forecasts over the forthcoming regulatory control period. The Victorian Government did not announce a timetable by which the moratorium would be removed.

The draft decision stated that given the uncertainty surrounding all the factors that make up AMI and TOU tariff impacts, the AER considered it reasonable to assume that there would be no material impact on maximum demand and energy consumption over the forthcoming regulatory control period.[215]

5.6.7.2 Victorian DNSP revised regulatory proposals

The DNSPs all disagreed with the AER's decision that TOU tariffs would have no material impact on maximum demand and energy sales over the forthcoming regulatory control period, however they have taken differing approaches in responding to the AER's draft decision. Essentially, the DNSPs have put forth three different positions on the impact of TOU tariffs on energy consumption over 2011–15:

- NIEIR has assumed that residential customers that are transferred to TOU from 2011 will reduce their overall consumption by 4 per cent by the end of 2015,

[215] AER, *Draft decision*, June 2010, p. 148.

while commercial customers will reduce their consumption by around 1 per cent. This was adopted by CitiPower, Powercor and United Energy.

- Frontier has reviewed available literature on TOU trials and smart meters generally, and estimated that residential customers transferring to TOU tariffs will reduce their consumption by 2.5 per cent by the end of 2015, while commercial customers will reduce consumption by 0.5 per cent. This was adopted by JEN.

- SP AusNet has used its own model incorporating proposed tariffs and elasticities to estimate that residential and small commercial customers transferring to TOU tariffs will reduce their consumption by 1.98 per cent by the end of 2015.

CitiPower and Powercor submitted that NIEIR's assumed TOU impacts in the form of a 2 per cent total reduction in maximum demand and 4 per cent total reduction in energy consumption by 2015 were conservative compared to TOU studies.[216] CitiPower and Powercor engaged Frontier to assess the reasonableness of NIEIR's forecasting methodologies, review the likely impact of policy adjustments on energy forecasts, as well as review ACIL Tasman's recommendations to the AER.[217]

JEN considered the analysis within the same Frontier reports, which were also attached to its revised regulatory proposal.[218] While JEN also engaged NIEIR to provide it an updated energy forecast (incorporating NIEIR's assessment of TOU impacts), JEN considered that Frontier's estimates of TOU energy reduction were more appropriate. Accordingly, JEN adjusted NIEIR's revised energy forecasts to reflect a 2.5 per cent reduction in residential energy consumption by 2015, instead of NIEIR's 4 per cent reduction. JEN also adjusted NIEIR's revised commercial energy forecasts to incorporate a 0.5 per cent reduction, instead of NIEIR's assumed 1 per cent reduction on commercial energy by 2015.[219] JEN considered that NIEIR's estimate of a 2 per cent reduction in maximum demand resulting from TOU tariffs was reasonable.

In its revised regulatory proposal, SP AusNet stated its view that the Victorian DNSPs must be compensated for the energy reduction impacts of TOU tariffs, or it would adjust the structure of its TOU tariffs to minimise the overall reduction in revenue associated with the introduction of the tariffs, which it submitted is in conflict with clause 6.18.5(b)(1) of the NER.

SP AusNet engaged NIEIR to provide updated forecasts of energy consumption however instructed NIEIR to explicitly remove its assumed impact of TOU tariffs from the forecast. SP AusNet then applied energy reductions to NIEIR's forecast to

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216 CitiPower, *Revised regulatory proposal*, July 2010, p. 107.

217 Frontier Economics, *Review of NIEIR's methodology for forecasting electricity consumption*, April 2010; Frontier Economics, *Review of policy adjustments—a report prepared for CitiPower*, July 2010; Frontier Economics, *Review of ACIL Tasman recommendations—a report prepared for CitiPower*, July 2010.

218 JEN, *Revised regulatory proposal*, July 2010, p. 42.

219 The AER notes that in JEN's revised regulatory proposal energy forecast, it erroneously included a 2.5 per cent reduction on commercial sales to account for the introduction of TOU tariffs from 2013, instead of Frontier's recommended 0.5 per cent. After questions from AER staff, JEN corrected this error and provided a revised reduction. JEN, *Response to information request of 19 August 2010*, 30 August 2010,

account for the change in consumption by customers that were moved to TOU tariffs in 2010, using its own TOU tariff model, slightly amended from its initial regulatory proposal model.[220]

However, SP AusNet did not incorporate any impact of new TOU tariffs for 2011–15, and instead proposed an adjustment to the calculation of reasonable estimates under the WAPC mechanism to mitigate the impact of expected changes in sales quantities resulting from the rollout of TOU tariffs during the 2011–15 regulatory control period.

CitiPower and Powercor suggested a similar adjustment to mitigate the expected impact of TOU tariffs on energy sales risk.[221]

United Energy submitted that the AER's draft decision to remove any impact of TOU tariffs from its energy forecast was effectively transferring 100 per cent of the risk associated with the uncertainty to United Energy, and is at odds with the Victorian Government's business case for the AMI rollout. United Energy stated that 'the AER accepted (the business case for the AMI rollout) in its decision to approve recovery of substantial costs from customers.'[222] United Energy also submitted a range of arguments supporting its view that customers will respond to the information provided by the AMI, regardless of TOU tariffs.

5.6.7.3 Submissions

The EUCV submitted that the focus of the AMI rollout was not on reducing the volume of electricity sold, but on shifting customer usage times. It also submitted that large customers (>160MWh/annum) have been subject to TOU tariffs and rising electricity prices for many years, and despite this, electricity consumption has continued to increase, suggesting that the mass rollout of TOU tariffs will not have a huge impact on customer consumption and that the own-price elasticity of demand is low.[223]

Origin Energy's (Origin) submission questioned Frontier's assertion that the bulk of energy savings resulting from the AMI rollout will arise from customers voluntarily electing to take up TOU tariffs, stating that the group of volunteering customers would be too small to deliver significant savings.[224] Origin questioned the magnitude of energy savings driven by in-home displays (IHDs) in Victoria, given the AMI rollout does not include the IHDs.

Origin also stated its view that customers electing to install an IHD, or utilise emerging energy efficiency technologies, would be conscious of both cost and environmental effects and that they would limit both maximum demand and consumption. Origin stressed its view that growth in consumption and maximum

220 The amendments to SP AusNet's revised regulatory proposal TOU tariff model were made in response to the draft decision statement that SP AusNet had failed to properly estimate the load shifting between periods in its initial proposal TOU tariff model. AER, draft decision, p. 154; SP AusNet, *Modelling of Time of Use and Critical Peak Demand Price Impacts (presentation)*, 24 August 2010.
221 SP AusNet, *Revised regulatory proposal*, July 2010, pp. 57–58.
222 United Energy, *Revised regulatory proposal*, July 2010, p. 267.
223 EUCV, *Submission to the AER*, August 2010, pp. 57–58.
224 Origin Energy, *Submission to the AER*, August 2010, p. 3.

demand should not be decoupled through the impact of TOU tariffs and other government policies and that '…there is a fundamental incoherence between rapidly growing peak demand and shrinking consumption.'[225]

In relation to the WAPC volumes assumptions for TOU tariffs, Origin asked that prior to the annual pricing process, the AER consider gathering information from the DNSPs on their working assumptions for the reasonable estimates of volumes, and share this information with retailers.[226]

VECCI noted that small businesses have limited ability to respond to changes in energy costs or invest in new energy saving assets, and have limited staffing resources to learn about energy saving practices.[227] It suggested that the AER should ensure that potential network benefits from AMI (relating to lower maximum demand) are achieved in the interests of consumers, and to a level that is commensurate with approved costs.[228]

The MJA report submitted by United Energy commented that the regulatory impact statement (RIS) and cost-benefit analysis prepared by the Victorian Government for the AMI rollout estimated 'modest' energy savings, although noted that these estimates did not include the impact of non-price incentives to reduce consumption, such as more information on energy use.[229]

MJA also provided some analysis of Melbourne customers' rising electricity bills since 1994, and stated its expectation that electricity prices would continue to rise over the forthcoming regulatory control period, in part due to the AMI rollout.[230] MJA stated its view that:

> …re-structured retail tariffs that deliver substantial benefits to consumers who are prepared to radically alter their energy use patterns are extremely unlikely to emerge in a competitive retail market. The only way that households and businesses will be able to reduce or maintain total annual electricity costs is to take advantage of Government energy efficiency policies and reduce total consumption of electricity wherever and whenever they can.'[231]

MJA raised the argument that increasing environmental awareness is likely to impact customer demand for electricity, noting the experience in the Victorian water sector as an example of consumer response in the absence of price signals.[232] MJA also discussed the impact that improved information (provided by AMI and expected Government information packages) could have on customer energy use, finding that United Energy is correct to assume some customer response to improved information about electricity consumption as part of its business processes. A

[225] Origin Energy, Submission to the AER, August 2010, p. 3.
[226] ibid., p. 4.
[227] VECCI, Submission to the AER, August 2010, p. 7.
[228] ibid., p. 10 and 17.
[229] Marsden Jacob Associates, *AER Treatment of UED Energy Sales Volume Forecasts*, 20 August 2010, pp. 21–22, footnote 49.
[230] ibid., pp. 30–33.
[231] ibid., p. 33.
[232] ibid., pp. 34–35.

s part of its analysis, MJA considered the Brattle Group study (which was discussed in the draft decision[233]) and a report by the American Council for an Energy-Efficient Economy (ACEEE) on the impact of AMI and information (customer feedback) programs, released in June 2010.[234] Upon request, United Energy provided the ACEEE report to the AER.[235]

5.6.7.4 Consultant review

ACIL Tasman noted the uncertainty surrounding the introduction of TOU tariffs, however stated its agreement that some adjustment to the electricity sales forecasts to account for the impact of the AMI rollout is reasonable.[236] In addition, ACIL Tasman considered that in the very least, increased customer information facilitated by the AMI rollout will have some small impact on consumption. [237] In considering what that impact should be, ACIL Tasman found that:

- NIEIR's revised assumption of a 4 per cent reduction for residential customers and slightly less than 1 per cent for commercial customers switching to TOU tariffs does not have a sound basis[238]

- Frontier's approach to calculating an estimated reduction is reasonable, however the resulting 2.5 per cent reduction for residential customers from 2011 is likely to overstate the impact of the AMI rollout on electricity sales, due to the moratorium (although ACIL Tasman noted that the date for the lifting of the moratorium was still unknown at the time of writing its report)[239]

- Similar to Frontier, SP AusNet's approach to calculating the impact is reasonable, although the impact (approximately 2 per cent reduction for affected residential and small commercial customers by 2015) is likely to be overstated due to the extension of the moratorium.[240]

ACIL Tasman stated that due to the absence of more detailed information on TOU tariff implementation and timing, including information on any transitional tariff arrangements, it was unable to provide a likely estimate of the impact of the AMI rollout on the Victorian DNSPs' energy forecasts.[241]

However, ACIL Tasman considered that Frontier's (applied by JEN) and SP AusNet's assumed reductions would be reasonable assumptions if the AER was certain that SP AusNet's proposed tariffs, or very similar tariffs, were to be introduced at a point in the forthcoming regulatory control period. [242]

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233 AER, *Draft decision*, June 2010, p. 150.
234 Marsden Jacob Associates, *AER Treatment of UED Energy Sales Volume Forecasts*, 20 August 2010, pp. 35–39; American Council for an Energy-Efficient Economy (ACEEE), *Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity Saving Opportunities*, June 2010.
235 United Energy, *Response to information request of 19 August 2010*, 20 August 2010.
236 ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 46.
237 ibid., p. 46.
238 ibid., p. 48.
239 ibid., p. 49.
240 ibid., p. 49.
241 ibid., p. 49.
242 ibid., pp. 49–50.

In relation to maximum demand, ACIL Tasman referred to its earlier consideration that there is limited research or data available on the impact of TOU tariffs on maximum demand, but stated that it does not consider NIEIR's estimated impact of 2 per cent reduction in maximum demand by 2015 to be unreasonable.[243]

5.6.7.5 Issues and AER considerations

Ultimately the TOU impacts recommended by NIEIR and Frontier Economics rest heavily on judgment, taking into account a wide variety of information and assumptions. While SP AusNet has presented an alternative detailed calculation, this too rests on judgment in selecting price elasticities and on key assumptions around pricing structures and government policy.

The AER has paid careful attention to the DNSPs' comments on risk, and agrees that its decision on the assumed impact of TOU tariffs involves a risk trade-off between customers and the DNSPs. Should the AER approve forecasts that incorporate an overstated assumption of the impact, then customers will face average prices that are higher than the amount required for DNSPs to recover the revenues set out in the AER's determination.

Conversely, should the AER determine an impact that understates the effect of customer response to TOU tariffs, the DNSPs will be constrained to set prices which are on average below the level required to recover their forecast revenues.

However, in either case, whether there is any adverse impact on the DNSPs' revenues depends on how DNSPs structure their tariffs. Moreover, an intended outcome of TOU tariffs is that users will better manage their consumption during peak times, resulting in an overall reduction in the network capacity required and in turn the DNSPs' costs.

The DNSPs' concern that they are exposed to potential reductions in revenue without any corresponding reductions in cost is consistent with the intended operation of and incentives under the WAPC — they have the ability to avoid this profit risk by setting prices reflective of marginal costs. However, to the extent marginal cost pricing is not a realistic outcome or is complicated by timing issues (as suggested by SP AusNet), or that there are non-pricing aspects of AMI that will affect consumption, there is some scope to consider TOU impacts as something beyond the control of the DNSPs.

The AER agrees that there are likely to be TOU tariffs in Victoria for some customers at some time in the forthcoming regulatory control period, and that some of those customers that are transferred to TOU tariffs are likely to change their behaviour and reduce their discretionary energy consumption by some proportion. However, determining what that proportion should be, and at what time it is likely to impact on the energy consumption is a highly ambiguous task at this point in time.[244] Given this uncertainty, the AER considers it is appropriate to be cautious in determining the DNSPs' energy forecasts, and to weigh up carefully all arguments.

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243 ibid., p. 42.

244 The AER notes VECCI's comments on the ability of small business customers to respond to TOU tariffs, which further exhibits the uncertainty surrounding customer responses in the forthcoming regulatory control period. VECCI, Submission to the AER, p. 7.

The AER notes United Energy's comment that 'the AER accepted (the business case for the AMI rollout) in its decision to approve recovery of substantial costs from customers.'[245] The AER's decision on cost recovery for the 2009–11 AMI rollout costs was pursuant to the AMI Order in Council, made by the Victorian Governor in Council under sections 15A and 46D of the *Electricity Industry Act 2000*. The AER did not have a role in assessing or accepting the business case (the net benefits) for rolling out AMI in Victoria. Its role was only to assess the roll-out costs given the decision by the Victorian Government to mandate the roll-out.

The following sections address further detailed considerations around the DNSPs' proposed TOU impacts, namely:

- the moratorium on TOU tariffs and related policy
- voluntary take up of TOU tariffs
- the pass through of network TOU pricing into retail tariffs
- assumed price elasticities
- feedback effect and in-home displays
- consistency between maximum demand and energy impacts.

TOU moratorium

CitiPower and Powercor noted that the moratorium on TOU tariffs was agreed only to the end of 2010, and stated their intention to introduce TOU in the forthcoming regulatory control period. CitiPower and Powercor noted various evidence of the Victorian Government's commitment to TOU tariffs, subject to customers initially being able to choose whether to take up the tariffs and adequate information and consultation to ensure a manageable transition.[246]

SP AusNet acknowledged the uncertainty created by the moratorium, however considered that this uncertainty reinforces the need for the AER to ensure DNSPs can recover at least their efficient costs.[247] Similarly, United Energy argued that removing the assumed impact of AMI from the energy forecasts serves to transfer 100 per cent of the risk posed by the uncertainty onto the DNSPs.[248]

In October 2010 (after the submission of revised regulatory proposals), the AMI Policy Committee recommended to the Victorian Government that the moratorium on TOU tariffs be extended for another year, to the end of 2011, to enable the Committee to properly consider all the implications the tariffs could have for various types of customers.[249] The AMI Policy Committee also recommended the use of temporary

245 United Energy, *Revised regulatory proposal*, June 2010, p. 267.
246 CitiPower, *Revised regulatory proposal*, June 2010, p. 103.
247 SP AusNet, *Revised regulatory proposal*, June 2010, p. 60.
248 United Energy, *Revised regulatory proposal*, June 2010, p. 267.
249 The AMI Policy Committee was established in March 2010 to advise the Victorian Government on issues related to the AMI rollout. The Committee consists of stakeholders from industry, consumer groups, regulatory bodies, the market operator, and energy ombudsman. Victorian Department of Primary Industries (DPI), *response to AER email on 7 October 2010*, 13 October 2010.

constraints around the differential between peak, off-peak and shoulder tariffs, once TOU tariffs are introduced, to be relaxed from the end of 2014. It recommended that the level of differentiation between peak, off-peak and shoulder tariffs should be comparable with peak/off peak or TOU tariffs currently available in the market.[250] The AER notes that such constraints will serve to mute the customer behavioural responses to the tariffs, at least in the early years of the next regulatory period, although the impact of increased information on energy use that the rollout of the tariffs would facilitate could still have a material impact on total energy consumption.

Voluntary TOU tariffs

Frontier's argument for including the impact of TOU tariffs in the DNSPs' forecasts rests on its assumption that, even if the moratorium is maintained for compulsory TOU tariffs, optional TOU tariffs are likely to be allowed, to enable the AMI to deliver benefits to customers.[251] Frontier's analysis of international TOU studies finds that the bulk of any reduction in consumption from the implementation of TOU will be driven by a minority of customers. Frontier cited studies showing that 75 per cent of overall energy savings are attributed to 20–25 per cent of participants.[252] Frontier therefore considers that customers who are likely to adopt TOU tariffs voluntarily will be those who can deliver the bulk of the energy savings expected from the AMI rollout.[253]

Frontier concluded that it is a small proportion of customers who are willing and able to change their consumption that will deliver the bulk of energy savings from the AMI rollout. The AER contends that customers likely to elect TOU tariffs may also be those whose energy use already fits the optimal TOU profile. That is, that for little or no change in behaviour, those customers will benefit from lower tariffs for the bulk of their electricity consumption. Customers who would need to shift or greatly reduce their energy consumption to achieve the status quo (being their bills for flat or two rate tariffs) would not be likely to take up TOU tariffs where they have a choice to maintain their current behaviour and bills. Consistent with Frontier's argument, the AER considers it likely that the bulk of the energy savings expected from TOU tariffs will be driven by those customers changing their behaviour by reducing or shifting their consumption in response to price incentives, which will involve those customers taking on some risk that they will face a higher bill, at least in the short term. However, the AER considers that this group of customers are unlikely to voluntarily adopt TOU tariffs due to the potentially higher bills and considerable changes in behaviour that the TOU tariffs would involve.

In addition, the 'rebound' arguments raised by ACIL Tasman will mute the effect of voluntary TOU tariffs, being that electricity is a small proportion of overall household costs, and that customers will simply adjust their behaviour back in the longer term. This suggests that, in the long term, the bulk of the energy savings will come from both the customers who do not have to change their behaviour much to achieve their

[250] Victorian Department of Primary Industries (DPI), *response to AER email on 7 October 2010*, 13 October 2010.

[251] Frontier Economics, *Review of ACIL Tasman recommendations—a report prepared for CitiPower*, July 2010, p. 4.

[252] Frontier Economics, *Review of policy adjustments—a report prepared for CitiPower*, July 2010, p. 24.

[253] Frontier Economics, *Review of ACIL Tasman recommendations—a report prepared for CitiPower*, July 2010, p. 4.

financial status quo, and those customers whose energy bills make up a larger proportion of their household income.

The addition of an 'opt out' clause in a voluntary TOU tariff package, as noted by Frontier, could distort these assumptions.[254] The AER considers that, should customers who have voluntarily elected TOU tariffs find that their behaviour must be significantly and inconveniently changed to achieve the financial status quo, they may elect to opt out of the voluntary tariff. Thus, those customers who are likely to deliver the bulk of the savings (being the customers who will shift their consumption in response to price incentives), even if they did select a voluntary TOU tariff, may abandon the tariff in favour of status quo.

Overall, the AER considers that the 'voluntary TOU' argument appears to be affected by the value that customers place on maintaining their current behaviour in the face of rising electricity prices. The AER considers that, contrary to Frontier's argument, it is not clear that the introduction of voluntary TOU tariffs will deliver the bulk of anticipated savings from the AMI rollout. The AER considers that customers who voluntarily take up TOU tariffs will include both customers who don't have to change their consumption much to benefit, as well as some customers who are willing and able to shift their consumption. Accordingly, the AER considers it would be inappropriate to forecast the total energy sales reductions due to AMI from the time at which voluntary TOU tariffs are introduced.

Flat load customers

In support of its 'voluntary tariff argument,' Frontier contended that as more 'flat load' customers switch to TOU tariffs, there are fewer customers left on the flat tariffs to subsidise those more 'peaky' customers (who are also left on flat tariffs). Frontier considers that this would require the DNSPs to increase the flat load tariffs relative to status quo, in order to recover the revenue necessary to serve those peaky customers. That increase in the flat tariffs would result in the remaining flat tariff customers reducing their energy consumption, further contributing to the overall impact of lower energy consumption resulting from the introduction of TOU tariffs.[255]

The AER has considered this argument, and makes the following points:

- as more customers switch away from flat load tariffs, and respond to the price incentives of TOU tariffs, there will be lower peak demand and less costs involved in supporting those remaining 'peaky' customers; and
- in any case, if facing fewer customers on flat load tariffs overall (meaning less support for the 'peaky' customers on those flat load tariffs), DNSPs may respond by increasing the off-peak rates on the TOU tariffs, which would have a lower impact on overall consumption yet enable the DNSPs to recover their costs.

As is discussed above, under the WAPC DNSPs have the ability to avoid the risk of under-recovering their costs by setting prices reflective of marginal costs. The WAPC also provides an incentive for DNSPs to maximise electricity sales, which they do by

[254] Frontier Economics, *Review of policy adjustments—a report prepared for CitiPower*, July 2010, p. 23.

[255] ibid., pp. 23–24.

restructuring tariffs in response to customer behaviour. SP AusNet has implicitly acknowledged this fact by arguing that if the AER's final decision energy forecasts do not incorporate the expected impact of TOU tariffs, then it would structure its tariffs to minimise the risk of a decline in consumption.[256]

While the likelihood or magnitude of each of these scenarios is unclear, the AER considers that Frontier's argument about a decline in consumption due to increases in flat load tariffs (following the introduction of TOU tariffs) has not been considered enough to contribute to the debate about the impact of TOU tariffs on the Victorian DNSPs' energy forecasts for the forthcoming regulatory control period.

Retail tariffs

CitiPower and Powercor rejected the AER's statement that DNSPs are prevented from sending price signals to customers, noting that trials of advanced meters where DNSP charges make up only a portion of the customer end price were relied upon by NIEIR and Frontier.[257] CitiPower stated that retailers have an incentive to pass through DNSP price signals to avoid under recovery of revenue, evidenced by retailers offering different charges in different distribution regions.[258]

The AER notes the comments on retailer incentives, however maintains its view that there is significant uncertainty surrounding the relationship between network TOU tariffs and retail tariffs. In addition, the potential for retailers to introduce TOU tariffs based on the fluctuating wholesale energy (spot market) prices complicates the relationship. The introduction of the CPRS could also result in increases in energy prices at peak times which will potentially overshadow price changes at the network level.

There is currently limited information on retailer responses to TOU network tariffs, and the AER considers that the assumption that the tariffs will be passed on to customers in full is unlikely. The complication of TOU energy prices and CPRS energy price impacts increases the uncertainty around the relationship between network TOU tariffs and retail tariffs.

Own price, cross price and substitution elasticities

Short term elasticities v. long term effects

CitiPower and Powercor stated that ACIL Tasman's assumption that demand for electricity is inelastic in the short term is inconsistent with its 'rebound' or fatigue effect.[259] CitiPower and Powercor also stated that just because some customers are unable to respond to the TOU tariffs doesn't mean that the majority of customers will be unable to respond by reducing their overall energy consumption.[260]

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[256] SP AusNet, revised regulatory proposal, p. 372.

[257] CitiPower, *Revised regulatory proposal*, July 2010, p. 105; Powercor, *Revised regulatory proposal*, July 2010, pp. 97–98.

[258] ibid.

[259] ibid.

[260] ibid.

Frontier argued against ACIL Tasman's reliance on the California State-wide Pricing Pilot to support its arguments for the 'rebound' and 'relativity' effects reducing customer responses to TOU tariffs over time.[261]

Frontier stated that in generating the estimated impact of TOU tariffs on energy consumption, both it and NIEIR allow for short term inelasticity of demand by smoothing the customer response and discounting short term savings. However, Frontier considered that the short term inelasticity effect potentially present in short term TOU trials may serve to underestimate the long run elasticity.[262]

CitiPower and Powercor highlighted differing definitions of the 'rebound effect':

- ACIL Tasman's assessment that as time passes, customers may become less responsive to TOU tariffs, as energy bills are a relatively small amount of disposable income, the principle agent problem and messages being lost over time

- Frontier's description that as appliances become more efficient, customers increase their level of comfort/use of the appliance given the cost of running the appliance is lower than it previously was.[263]

CitiPower and Powercor argued that as TOU tariffs do not entail any increases in appliance efficiency, the rebound effect (as described by Frontier) is not relevant.[264] However, the AER notes that regardless of the differences in descriptions of the rebound effect, the effects described by ACIL Tasman are still legitimate considerations when forecasting customer responses to TOU tariffs.

The AER considers that Frontier's and NIEIR's approaches of dealing with short term inelasticity of demand by smoothing the customer response and discounting short term savings further demonstrates the uncertainty around the impact of the tariffs over the 2011–15 regulatory control period, and the imprecise nature of the estimates made by Frontier and NIEIR.

Off peak price elasticities

In its revised regulatory proposal, SP AusNet responded to the draft decision comments that the AER considers there would be some response to a price increase (or decrease) to off peak prices, however, it is uncertain what that response would be.[265] SP AusNet pointed out that this demonstrates the uncertainty and risk faced by the DNSPs introducing TOU tariffs. SP AusNet's point appears to be that should the AER assume that if off peak prices are introduced that are lower than the current flat load tariffs, and that customers will increase their off peak consumption relative to the status quo (in addition to shifting load from peak and shoulder periods to off peak times), this results in additional risk for SP AusNet.

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261 CitiPower, *Revised regulatory proposal*, July 2010, p. 106; Powercor, *Revised regulatory proposal*, July 2010, pp. 98–99; Frontier Economics, *Review of ACIL Tasman recommendations—a report prepared for CitiPower*, 20 July 2010, pp. 5–6.

262 Frontier Economics, *Review of ACIL Tasman recommendations—a report prepared for CitiPower*, 20 July 2010, p. 5.

263 CitiPower, *Revised regulatory proposal*, July 2010, p. 106; Powercor, *Revised regulatory proposal*, July 2010, p. 99.

264 CitiPower, *Revised regulatory proposal*, July 2010, pp. 106–107; Powercor, *Revised regulatory proposal*, July 2010, p. 99.

265 AER, *Draft decision*, June 2010, p. 154.

This is similar to the argument raised in the context of other government policies, (for example, the insulation rebate), that following the installation of insulation, customers will respond by increasing their expected 'comfort' levels which offsets the impact of the policy on reducing energy demand. The AER considers it equally possible that when customers face a lower price than status quo at off peak periods, they increase their consumption at this time, offsetting the expected overall fall in consumption due to the higher peak and shoulder prices. In any case, the AER disagrees with SP AusNet's assumption that the own-price elasticity of demand at off peak times is zero.

Lagged elasticities

SP AusNet stated that it considered the results of empirical studies demonstrating a lagged elasticity for price increases are meaningless in the case of the Victorian AMI rollout. This is because the price increases within such studies are small and incremental, while its TOU tariffs are likely to involve large scale changes which would result in customers instantaneously having greater regard to how they use their energy consuming appliances.[266]

The AER reiterates its comments in the draft decision regarding the scale of the price changes proposed by SP AusNet as part of the introduction of TOU tariffs, being that estimating the effect of such large scale changes in tariffs is highly uncertain. SP AusNet claims to have considered this and accordingly applied 'discounted' elasticity estimates. However, SP AusNet also stated that its discounted elasticity estimates were also selected to account for the impact of other concurrent policies on elasticity of demand.[267]

The recommendation of the AMI Policy Committee to the Victorian Government that, once the TOU moratorium is lifted, it should constrain the differential between peak and off peak prices for a period of time undermines SP AusNet's argument that the introduction of the tariffs will have an immediate and full impact on customer behaviour.[268] In addition, the discussion above on the likelihood of retailers passing through the network TOU tariffs, and the potential for the impact of the CPRS on wholesale energy prices to swamp the network tariff changes is also contrary to SP AusNet's claims that customers will instantaneously respond to the new price signals. The AER considers that it is appropriate to assume a lagged elasticity of demand in considering the impact of the AMI rollout in Victoria.

2006 EDPR

The DNSPs' arguments about incorporating an elasticity of demand for energy for the forthcoming regulatory control period are in stark contrast to their arguments during the 2006 Electricity Distribution Price Review (2006 EDPR).[269] The impact of the ESCV's 2006 final determination resulted in real network price decreases over the 2006–10 regulatory control period. As a result, the ESCV attempted to calculate the likely customer response to falling network charges by incorporating estimated elasticities for residential and non-residential customers. This resulted in an increase in the energy forecasts approved in the ESCV's draft decision. In their revised

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[266] SP AusNet, *Revised regulatory proposal*, July 2010, pp. 58–59.

[267] SP AusNet, *Revised regulatory proposal*, July 2010, p. 59.

[268] Victorian Department of Primary Industries (DPI), *response to AER email on 7 October 2010*, 13 October 2010.

[269] ESCV, Electricity Distribution Price Review 2006–2010, vol. 1, October 2006, pp. 150–153.

regulatory proposals, the DNSPs argued against the ESCV's calculation of elasticity and customer response. Among other reasons, the DNSPs' argued that the ESCV's approach was unreasonable because:

- the adjustment assumes all retail tariffs will change immediately when distribution tariffs change, which is prevented by retail price caps and market contracts
- the adjustment assumes no other components of retail tariffs will change, for example changes in generation costs could outweigh any distribution price decrease
- the value of the elasticity used (being –0.1 per cent for residential and –0.025 per cent for non-residential customers) was inappropriate
- the adjustment may give DNSPs the incentive to adopt tariff strategies that mitigate any revenue risk as a result of the elasticity adjustment
- the adjustment is unprecedented and unanticipated.[270]

The ESCV noted the high level of uncertainty around the extent to which electricity prices would affect energy consumption, and as it found it difficult to find an appropriate elasticity estimate, did not adjust the DNSPs' energy forecasts for elasticity impacts in its final decision.[271]

The AER points out that the arguments raised by the DNSPs in the 2006 EDPR are also relevant for the AER's consideration of energy forecasts for the 2011–15 regulatory control period, notably:

- the AER has commented on retail price barriers in the discussion above, noting that a straight pass through of the TOU tariffs to customers is unlikely. In addition, the impact of the CPRS on wholesale market prices has the potential to outweigh any TOU tariff impacts on customer behaviour
- the elasticities considered inappropriate (too high) by the DNSPs in 2006 are in fact lower than the elasticities proposed by SP AusNet in its modelling of the TOU tariff impact on peak consumption for residential customers
- under the WAPC, the DNSPs have an incentive and the ability to adopt tariff strategies that mitigate the revenue risk posed by the TOU tariffs.

Similar to the ESCV's consideration of the impact of the real price decreases on energy consumption over the current regulatory period, the AER considers that there is a significant level of uncertainty surrounding the impact of TOU tariffs on customer energy consumption in the 2011–15 regulatory control period.

Elasticity assumptions
In its revised regulatory proposal TOU model, SP AusNet has assumed the following elasticities for both residential and business customers transferring to TOU tariffs:

[270] ibid., p. 151.
[271] ibid., p. 152.

- –0.15 for the own price elasticity of peak summer/winter and shoulder demand
- between –0.005 and –0.1 for cross price elasticity of demand
- own-price elasticity of demand for off peak periods of zero.[272]

SP AusNet's initial regulatory proposal identified a lack of available data on customer response to TOU tariffs in Australia. It listed elasticities reported in studies by NIEIR, Monash University and Faruqui and George, which ranged between –0.15 and –0.5, and determined that its own proposed elasticities were conservative.[273] In its revised regulatory proposal, SP AusNet stated that its conservative (or 'discounted') elasticity assumptions are to account for the possibility of a lagged customer response to the TOU tariffs.[274]

Frontier commented on the use of elasticities by NERA Economic Consulting (NERA) in its report for the MCE on the cost-benefit analysis of a smart meter rollout in each jurisdiction of the NEM.[275] In its base case for Victoria, NERA input elasticities based on the outcome of the California State-wide Pricing Pilot Study, which were:

- for residential customers:
  - own-price elasticity of demand between 0.041 to –0.044 in summer
  - own-price elasticity of demand between –0.011 to –0.019 in winter
  - elasticity of substitution of –0.069 to –0.076 in summer
  - elasticity of substitution of –0.025 in winter
- for commercial customers:
  - own-price elasticity of demand of –0.02.[276]

NERA recognised that these elasticity assumptions may be too conservative, however instead of adjusting the elasticities, adopted a 'high demand response' scenario involving a greater reduction in consumption than that implied by the elasticities. Frontier speculates that this assumption by NERA is due to a lack of elasticity results reported in Australian trials, and the fact that while the Californian trial showed no overall reduction in consumption resulting from TOU tariffs, some Australian AMI trials (such as Country Energy's Home Energy Efficiency Trial) show positive reductions.[277] Frontier did not make any conclusions on appropriate elasticities to apply, although noted that the NERA elasticities were likely to be low.

272 SP AusNet, *Revised regulatory proposal—TOU tariff model.*
273 SP AusNet, *Electricity Distribution Price Review*, *Regulatory Proposal*, November 2009, p. 93–94.
274 SP AusNet, *Revised regulatory proposal*, July 2010, p. 59.
275 Frontier, *Review of policy adjustments–a report prepared for CitiPower, June 2010*, pp. 20–21.
276 ibid., p. 20.
277 ibid.

ACIL Tasman stated that there is significant reason to be cautious in relation to SP AusNet's elasticity estimates, given the majority of the trials to which SP AusNet referred were not conducted in Australia. However, given SP AusNet's assumed elasticities are approximately half of the elasticities assumed in the trials to which it refers (and are therefore conservative), ACIL Tasman stated that the assumed reduction in energy consumption was not unreasonable (putting aside the likelihood that the tariffs proposed would be introduced).[278]

The AER has conducted a literature review of reported elasticities of maximum demand and energy consumption, including studies by Farqui and George, NERA, NIEIR, Navigant Consulting, Monash University and the Brattle Group.[279] Table 5.22 sets out the range of elasticity assumptions reported within these studies, as compared to SP AusNet's assumptions.

278 ACIL Tasman, *Review of revised growth forecasts,* October 2010, pp. 48–49.

279 Ahmad Farqui and Stephen S. George, *The Value of Dynamic Pricing in Mass Markets*, The Electricity Journal, July 2002; NIEIR. *The Own Price Elasticity of Demand in NEM Regions*, June 2007; The Brattle Group (various), *Household Response to Dynamic Pricing of Electricity,* 10 January 2009; Monash University (Dr. Shu Fan and Prof. Rob J. Hyndman), *The Price Elasticity of Electricity Demand in South Australia and Victoria*, 22 October 2008; NERA Economic Consulting, *Demand side response - Time of use tariffs and critical peak pricing, Cost Benefit Analysis of Smart Metering and Direct Load Control*, 29 February 2008; Navigant Consulting Inc, *Evaluation of Individual Metering and Time of Use Pricing Pilot—Presented to Oakville Hydro Electricity Distribution Inc.*, 18 March 2008.

Table 5.22 Range of reported elasticities resulting from AER literature study

Elasticity	Reports	Results	SP AusNet's assumptions
Elasticity of demand (consumption)	Farqui and George (2002), NIEIR (2007), Brattle Group (2009)	–0.02 to –0.5	n/a
Elasticity of demand (maximum demand)	Farqui and George (2002), Monash University (2008)	–0.28 to –0.42	n/a (SP AusNet adopt NIEIR's assumption of a 2 per cent reduction in energy by 2015)
Own-price elasticity—peak period	NERA (2008), Navigant Consulting (2008), Monash University (2008), Brattle Group (2009)	–0.02 to –0.79	–0.15
Elasticity of substitution	Brattle Group (2009), Farqui and George (2002)	+0.4 to –0.4	n/a
Cross price elasticity—peak to off peak	Farqui and George (2002), NERA (2008), Navigant Consulting (2008), Brattle Group (2009)	–0.01 to –0.4	–0.005 to –0.008
Cross price elasticity—peak to shoulder	Navigant Consulting (2008), Brattle Group (2009)	–0.03 to –0.4	–0.008 to –0.1
Cross price elasticity—shoulder to off peak	Navigant Consulting (2008), Brattle Group (2009)	–0.03 to –0.19	–0.008

Note: Reported elasticities are for small customers, and range between short run and long run assumptions.

Table 5.22 demonstrates the level of variance in reported elasticities resulting from TOU tariff trials internationally. While SP AusNet's proposed own-price peak period elasticity is at the lower end of the range reported in studies, SP AusNet's assumed cross price elasticities are below the reported range. This indicates that SP AusNet considers the level of load shifting between periods will be lower than trials suggest.

The AER agrees that SP AusNet's assumed own-price elasticity of demand in peak and shoulder periods is reasonably conservative, and therefore acceptable to use in forecasting energy consumption for the following period. The AER agrees that given the estimates are conservative, they account for any lagged customer response to the new tariffs, and should be applied according to the implementation of TOU tariffs.

As discussed above and in the draft decision, the AER considers that SP AusNet's estimate that the own-price elasticity of off peak consumption is zero is incorrect. The AER considers it is highly likely that in the face of falling (rising) off-peak prices, customers would respond by increasing (decreasing) their consumption, beyond the load shifting from peak and shoulder periods. In addition, the AER notes that SP AusNet's cross-price elasticities for peak and shoulder periods are below the range of reported trial outcomes, set out in table 5.22. However, the AER has considered ACIL Tasman's general recommendation that, should SP AusNet's proposed tariffs be implemented, then its own estimated impact is unlikely to unreasonable, given it assumes elasticities of roughly half of its selected studies.[280] Given the difficulty of estimating a non-zero off-peak own price elasticity, and the likely low materiality of the assumption for SP AusNet's energy forecasts over 2011–15, the AER accepts SP AusNet's elasticity assumptions as reasonable.

Feedback effect and in-home displays

Frontier argued that despite the moratorium on TOU tariffs, the capability for in-home displays suggest that the AMI meters will have some impact on customer energy consumption.[281]

Similarly, CitiPower and Powercor submitted that even if the AER does not accept that TOU tariffs will reduce energy consumption in the forthcoming regulatory control period, other emerging technologies (not considered by NIEIR) should be considered, including Google PowerMeter.[282] Google PowerMeter is a free internet based tool that customers with a smart meter can sign up for to provide real time information on their energy usage and costs. It effectively provides customers with a similar level of information as that enabled by in-home displays, via their home computers.[283]

While the AMI rollout in Victoria does not include the rollout of in-home displays, the AMI communications systems are compatible with a range of in-home devices, likely to be offered to customers as part of retail tariff packages.

United Energy submitted that the additional information provided to customers via their AMI meters will result in a reduction in energy consumption, regardless of the introduction of TOU tariffs. UED provided an example of the impact of customer information on the Victorian demand for water.[284]

United Energy also referred to a report published by the American Council for an Energy Efficient Economy (ACEEE) in June 2010, which provides a summary of numerous studies into customer responses to information about energy consumption.[285] UED listed the types of feedback likely to lead to a customer response, including:

- enhanced billing—providing customers with more detailed information about energy consumption patterns
- estimated feedback—providing customers with a detailed account of electricity use by major appliances and devices, such as web-based devices (for example, Google PowerMeter, discussed above)

280 ACIL Tasman, *Review of revised growth forecasts*, October 2010, p. 48.
281 Frontier Economics, *Review of ACIL Tasman recommendations—a report prepared for CitiPower*, 20 July 2010, p. 4.
282 CitiPower, *Revised regulatory proposal*, July 2010, p. 107.
283 Google PowerMeter website, available at: http://www.google.com/powermeter/about/index.html. Accessed 12 August 2010, 1:45pm.
284 United Energy, *Revised regulatory proposal*, July 2010, p. 267.
285 ibid., p. 268.

- real-time feedback—in-home display devices providing real time information about energy use and costs, including by appliance type.[286]

United Energy also noted that the way in which the feedback is provided is critically important in generating a customer response, in particular the quality of the information and customer ability to understand it.[287] Overall, United Energy submitted that if customers are able to extract meaningful information from their AMI meter, supported by messages linking energy conservation to amelioration of climate change impacts, customers will reduce their energy consumption.[288]

Various studies on smart meters have attempted to measure the results of providing information to customers on their energy consumption, including EnergyAustralia's Critical Peak Pricing Trial. A 2007 paper on this trial stated that interim results indicate that providing information to customers on their energy use at peak times can result in a significant energy saving. However, it also stated that international experience suggests that the information only effect may diminish over time.[289]

The mandated AMI rollout does not include IHDs, and there is currently no evidence to suggest that there will be widespread take up of the devices in the forthcoming regulatory control period, such that it is appropriate to assume a separate 'information effect' will influence all customers receiving a smart meter. However, the AER agrees that there is likely to be some change in energy consumption due solely to the fact that customers will have more information on their energy use following the AMI rollout. However, separating the magnitude of this information effect from the impact of TOU tariffs is highly uncertain at this point in time.

Overall assumptions—average customer reduction in consumption and maximum demand

Between its initial and revised reports for the DNSPs, NIEIR reduced its assumed reduction in energy consumption due to TOU tariffs from 8 per cent to 4 per cent per year.[290] However, NIEIR's revised reports indicate that it maintained its original 2 per cent reduction in maximum demand due to TOU tariffs. NIEIR's revised reports state that it has assumed TOU tariffs will be introduced from 2013, with the majority of the impact on residential energy being in the period 2013–15.[291]

After considering the AER's draft decision, NIEIR's assumptions and a range of issues relating to the AMI rollout including voluntary TOU tariffs, feedback effects, in-home displays, retail tariffs, and elasticities, Frontier recommended that an appropriate assumption is that residential customers will consume 2.5 per cent less and

286 ibid., p. 268–9.
287 ibid., p. 269.
288 ibid., p. 271.
289 Alex Millar, *EnergyAustralia's Critical Peak Pricing Trial: Sample design, customer acquisition and Initial Demand Response*, 30th International Conference for the International Association for Energy Economics, Wellington, New Zealand, 18-21 February 2007, p. 19.
290 For example see NIEIR, *Electricity sales and customer number forecasts to 2019 for the JEN Electricity region*, June 2010, p. 74.
291 For example see NIEIR, *Maximum summer demand forecasts for Jemena Electricity Networks to 2020*, June 2010, p. 56.

commercial customers 0.5 per cent less by 2015 than the case where no AMI meters and TOU tariffs are rolled out.[292]

As noted above, applying SP AusNet's TOU model to NIEIR's base energy consumption forecast (with the impact of the AMI rollout removed) results in residential and small commercial customers' energy consumption being 1.98 per cent lower by 2015 than it would otherwise have been.[293]

CitiPower and Powercor submitted an additional report prepared in 2007 by Frontier Economics (UK) on the costs and benefits of smart meter and visual display unit rollouts to residential and small business customers in Great Britain.[294] Frontier Economics' (UK) analysis of the literature and trial results available at the time indicated a level of uncertainty about customer response and noted the selection bias problems with trials.[295] It referred to a large smart meter trial being conducted by Ofgem that is expected to clarify the uncertainty around customer response to time of use pricing, the results of which are to be known in late 2010.[296] In the absence of any firm trial results, Frontier Economics (UK) assumed a 'conservative' estimate of energy reduction of 2 per cent for domestic credit customers, 1 per cent for domestic prepayment customers and 0.25 per cent for small business customers.[297] This was based on a report by Sustainability First which found that smart meters, as part of a package of energy saving initiatives, might produce a domestic market reduction in the range of 1 to 3 per cent.[298]

While the AER acknowledges differences between the Great British and Victorian electricity markets and customers, the variation in advice provided by Frontier Economics (UK) and Frontier Economics (Australia) further exhibits the high degree of uncertainty as to the impact of smart meters on customer energy consumption.

The AER has considered the differing approaches to estimating the impact of TOU tariffs on energy consumption over 2011–15, in the context of the AMI Policy Committee recommendations to extend the TOU tariff moratorium and constrain the differential between peak and off-peak prices. The AER has considered the arguments raised by the DNSPs, ACIL Tasman, NIEIR, Frontier, stakeholder submissions, as well as published information from international and national smart meter and TOU tariff trials. On balance, the AER considers that the estimated impacts recommended by Frontier and calculated by SP AusNet are likely to reflect a reasonable expectation of customer response to TOU tariffs, while the impact estimated by NIEIR is likely to be overstated, and result in energy forecasts for 2011–15 that are unreasonably low.

The AER notes that SP AusNet's TOU model calculations rest on its proposed tariffs, which themselves are subject to some uncertainty, given the AMI Policy Committee

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292 Frontier, *Review of policy adjustments–a report prepared for CitiPower, June 2010*, pp. 26–27.

293 SP AusNet, *TOU tariff model*, amended version provided to the AER on 13 October 2010.

294 Frontier Economics, *Smart metering—A report prepared for Centrica*, October 2007.

295 ibid., p. 45.

296 Ofgem, *Energy Demand Research Project*, website information: http://www.ofgem.gov.uk/Sustainability/EDRP/Pages/EDRP.aspx, accessed 9 September 2010, 2:41pm.

297 Frontier Economics, *Smart metering—A report prepared for Centrica*, October 2007, p. 45.

298 ibid.; Sustainability First, *Smart meters in Great Britain: the next steps? Paper 4 : Smart meter contribution to UK goals for energy saving and carbon reduction*, July 2007, pp. 30–36 and *Paper 4 : Smart meter contribution to UK goals for energy saving and carbon reduction.*

recommendation that constraints should apply to the differential between peak, shoulder and off-peak tariffs at least until 2015. However, the AER considers that at this time it is not possible to determine alternative tariffs to use as inputs into SP AusNet's TOU tariff model.

Impacts on maximum demand

The draft decision noted NIEIR's inconsistent analysis when estimating elasticities for the impact of the AMI rollout on energy consumption and maximum demand. It stated that NIEIR should have examined available literature on the impact of AMI on maximum demand, as it did for energy consumption.[299] CitiPower and Powercor submitted that by considering the Brattle Group study, which is a survey of recent experiments on TOU tariffs and maximum demand, NIEIR did in fact account for the relevant underlying studies.[300]

ACIL Tasman stated that it does not consider NIEIR's estimated impact of 2 per cent reduction in maximum demand by 2015 to be unreasonable, given there is limited research or data available on the impact of TOU tariffs on maximum demand.[301]

Origin submitted that growth in consumption and maximum demand should not be decoupled through the impact of TOU tariffs.[302] As stated in the draft decision, the AER considers that the DNSPs' and NIEIR's assumptions of disproportionate reductions in energy and maximum demand due to the AMI rollout are unlikely.

However, the AER notes that to forecast an overstated impact of the AMI rollout on maximum demand, such that planned capital expansion is deferred, runs the risk of the DNSPs' failing to meet their service standard requirements in the forthcoming regulatory control period. It also runs the risk of more severe outages in the face of an unusually hot summer, such as that experienced in January 2009. The AER notes VECCI's submission that the network benefits of AMI should be passed through to consumers from the latter years of the forthcoming regulatory control period, given the AMI rollout will be completed.[303] However, the reliability of customer response to price signals at times of maximum demand is highly uncertain at present, such that forecasting a significant reduction in maximum demand-driven capital poses undue service reliability risks. The AER expects that further trials and information generated via AMI, including critical peak pricing trials, will better inform its assessment of expenditure driven by maximum demand growth in the 2016–20 regulatory control period.

In the absence of a better understanding of how customers are likely to respond to TOU tariffs on maximum demand days, the AER considers it is reasonable to err on the side of caution when forecasting maximum demand for the forthcoming regulatory control period. The AER expects that better information on customer behaviour (which is facilitated by the AMI rollout) will deliver more certainty in forecasting maximum demand for future regulatory control periods.

[299] AER, *Draft decision*, June 2010, p. 149.
[300] CitiPower, *Revised regulatory proposal*, July 2010, pp. 102–103.
[301] ACIL Tasman, *Review of revised growth forecasts,* October 2010, p. 42.
[302] Origin Energy, *Submission to the AER*, August 2010, p. 2.
[303] VECCI, *Submission to the AER*, August 2010, p. 9.

The AER considers that the Victorian Government's intention to constrain the differential between peak and off peak prices for the first phase of TOU tariffs indicates it is unlikely that there will be critical peak pricing in the forthcoming regulatory control period in Victoria. This means that there is unlikely to be any significant price incentive for customers to reduce their consumption during maximum demand periods.

The AER considers NIEIR's conservative assumption that the AMI rollout will result in an overall reduction in maximum demand of 2 per cent by 2015 is appropriate for the maximum demand forecasts in the forthcoming regulatory control period.

Reasonable estimates approach

Noting the uncertainty described above, the AER considered an alternative methodology to account for the impact of TOU tariffs on consumption in the forthcoming regulatory control period was through the DNSPs' annual pricing proposals. In particular, the AER considered the merits of accounting for the new tariffs within the calculation of 'reasonable estimates' for the TOU tariff sales volumes, as suggested by SP AusNet, CitiPower and Powercor in their revised regulatory proposals, and noted by Origin in its submission.[304] The AER consulted with the Victorian DNSPs on the operation and calculation of the proposed 'reasonable estimates', however was unable to reach an agreement on the exact operation of such a mechanism. Accordingly, the AER did not apply the 'reasonable estimates' approach as part of this final decision.

5.6.7.6 AER conclusion

The Victorian DNSPs, NIEIR and Frontier have all argued that despite the uncertainty surrounding the introduction of TOU tariffs, including estimating the likely effect of the tariffs on customer behaviour, it is reasonable to assume that some impact should be estimated and factored into the forecasts.

The calculation of impacts on energy consumption is highly complex and rests on a large number of uncertainties, not only about elasticities, but also about the future timing and structure of TOU tariffs. However, the AER agrees that assuming no impact on energy consumption due to the AMI rollout would place undue risk of declining consumption onto the DNSPs, and may result in adverse incentives that will affect the rollout of TOU tariffs.

As a result of the AER's considerations and conclusions outlined above, in determining appropriate amounts, values and inputs into the PTRM for the purposes of clause 6.12.1(10) of the NER, the AER has:

- for CitiPower, Powercor and United Energy—removed the estimated impact of TOU tariffs calculated by NIEIR from the revised regulatory proposal energy forecasts, and applied Frontier's estimated impact to the forecasts, commencing in 2012

[304] SP AusNet, *Revised regulatory proposal*, July 2010, pp. 369–371; CitiPower, *Revised regulatory proposal*, July 2010, p. 78; Powercor, *Revised regulatory proposal*, July 2010, p. 72.

- for JEN—applied JEN's corrected calculation of the Frontier estimated impact to the NIEIR base energy forecast for JEN (after removing NIEIR's estimated impact), commencing in 2012[305]
- for SP AusNet—applied SP AusNet's own calculation of estimated impacts of TOU tariffs on NIEIR's base energy forecast (after removing NIEIR's estimated impact), using SP AusNet's TOU tariff model, with TOU tariffs commencing in 2012.

5.6.8 Other issues—Rule requirements

This section responds to an issue raised by CitiPower and Powercor in relation to growth forecasts that is not considered in the sections above.

The draft decision stated that clause 6.12.1(10) of the NER requires the AER to make a decision on appropriate amounts, values or inputs, including forecasts of maximum demand, energy consumption and customer numbers which are inputs to the capex and opex assessments, and the PTRM and subsequently X factors.[306]

CitiPower's and Powercor's revised regulatory proposals disputed the AER's reading of clause 6.12.1(10) of the NER, stating that their maximum demand forecasts cannot be considered 'other' amounts for the purposes of that clause. CitiPower and Powercor submitted that the AER must accept the total capex and opex forecasts if it is satisfied that they reasonably reflect the opex and capex criteria, including that they reflect a reasonable expectation of the demand forecast required to achieve the capex and opex objectives.

CitiPower and Powercor submitted that the AER is not permitted by the NER to substitute maximum demand forecasts it considers 'appropriate.' They also submitted that in considering new customer connections capex, the AER must consider the total forecast capex against the capex criteria, and that it cannot rely on clause 6.12.1(10) of the NER to substitute customer number forecasts.[307]

The AER considers that maximum demand forecasts, energy sales forecasts and customer number forecasts are amounts, values or inputs for the purpose of clause 6.12.1(10) of the NER.

Maximum demand forecasts and customer number forecasts are inputs to the total capex and opex forecasts. The AER must accept the total capex or opex forecast if it is satisfied that the forecast reasonably reflects the capex or opex criteria (clause 6.5.7(c) and 6.5.6(c) of the NER), and may only adjust the total capex or opex forecast to the extent necessary to enable it to be approved in accordance with the NER (clause 6.12.3(f)).

In assessing whether a DNSP's proposed total capex or opex forecast reasonably reflects the capex or opex criteria, it is necessary for the AER to assess whether the demand forecasts and customer number forecasts which the proposed total capex or

305 JEN, *Response to information requested on 19 August 2010*, 30 August 2010.
306 AER, *Draft decision*, June 2010, p. 73.
307 CitiPower, *Revised regulatory proposal*, July 2010, p. 90; Powercor, *Revised regulatory proposal*, July 2010, pp. 82–83.

opex forecast is based on are realistic or reasonable. If a DNSP’s demand forecasts or customer number forecasts are not realistic or reasonable and as a result the AER is not satisfied that the DNSP’s total capex or opex forecast reasonably reflects the capex or opex criteria, the DNSP’s demand forecasts or customer number forecasts need to be adjusted. The adjustment should be such that it will cause the DNSP’s total capex or opex forecast to be amended to the extent that in the AER’s view it reasonably reflects the capex/opex criteria.

5.7 AER conclusion

For the reasons outlined in sections 5.6.5 and 5.6.6, the AER considers that the spatial maximum demand forecasts proposed by Powercor, JEN and United Energy are reasonable and reflect a realistic expectation of the demand forecasts required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER.

The AER considers that the spatial maximum demand forecasts proposed by CitiPower and SP AusNet do not reflect a realistic expectation of the demand forecasts required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER. In place of CitiPower's and SP AusNet's proposed maximum demand forecasts, this final decision approves the forecasts as set out in tables 5.23 and 5.26 below. In substituting the proposed forecasts, the AER has made the minimum necessary amendments to enable the forecasts to be approved in accordance with the NER, as required by clause 6.12.3(f) of the NER.

Given the Victorian DNSPs' revised regulatory proposal customer number forecasts reflect reasonable population and economic growth forecasts, as discussed in section 5.6.3, the AER considers they are appropriate to form amounts, values or inputs to the AER's determination under clause 6.12.1(10) of the NER.

The AER considers that the Victorian DNSPs' revised regulatory proposal energy consumption forecasts reflect unreasonable assumptions about the one-watt standby target policy and the introduction of time of use (TOU) tariffs in Victoria, as discussed in sections 5.6.4 and 5.6.7. In particular, the AER considers there is insufficient evidence of a government policy to implement one watt standby targets for all household appliances, and that customer behaviour has moved ahead of the 2002 National Standby Strategy, negating the need for the policy to be properly implemented via a mandatory target scheme. Following the extension of the Victorian Government's moratorium on TOU tariffs and its intention to apply constraints to differentials between peak and off-peak prices, the AER considers that NIEIR's assumption on customer response to TOU tariffs by 2015 does not reflect a reasonable expectation of energy consumption. In making this final decision, the AER has made the following amendments to the DNSPs' energy forecasts:

- CitiPower, Powercor and United Energy—removed the one-watt standby target assumption; removed NIEIR's assumed impact of TOU tariffs and replaced it with Frontier's estimated impacts for residential and commercial customers, commencing in 2012

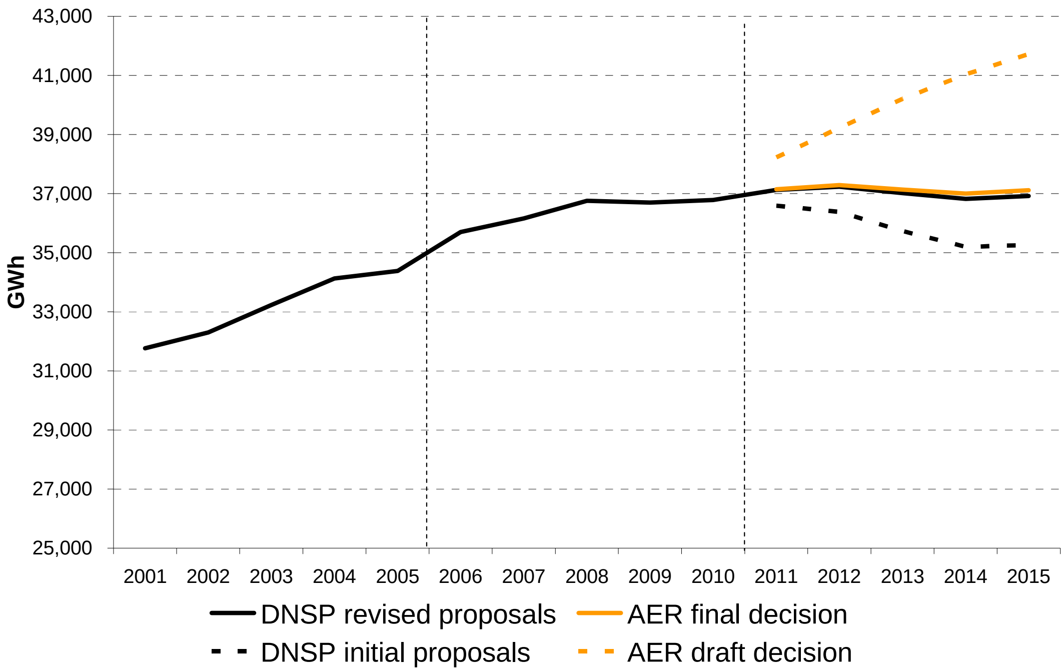
- JEN—removed the one watt standby target assumption; applied JEN's corrected calculation of Frontier's estimated impacts of TOU tariffs for residential and commercial customers, commencing in 2012

- SP AusNet—removed the one watt standby target assumption; applied SP AusNet's own calculation of estimated impacts of TOU tariffs using its TOU tariff model, commencing in 2012.

These amendments to the revised regulatory proposal energy forecasts have been made by requesting the DNSPs to model the AER's final decisions, and are the minimum necessary amendments to enable the forecasts to be approved in accordance with the NER, as required by clause 6.12.3(f) of the NER.

Figure 5.7 sets out the AER's final decision on forecast energy sales. The chart indicates that the AER has largely agreed with the forecasts proposed by the Victorian DNSPs. It also illustrates that the DNSPs responded to the AER's draft decision through updating their forecasts and moderating the presumed impact of certain energy efficiency measures (including TOU tariffs), as well as correcting the AER's draft decision population growth adjustments. The AER has also largely accepted the DNSPs' customer number and maximum demand forecasts, which are inputs into several elements of the DNSPs' forecast expenditures.

Figure 5.7 Victorian DNSP historical and forecast energy sales



Source: DNSP revised proposal RIN templates 6.3, AER analysis

In place of the Victorian DNSPs' proposed energy consumption forecasts, this final decision approves the forecasts as set out in tables 5.23 to 5.27 below.

Table 5.23 AER conclusion on growth forecasts—CitiPower

	2011	2012	2013	2014	2015
Sum of non-coincident ZSSs (MW)	1 510	1 552	1 593	1 634	1 677
Energy consumption (GWh)	6 180	6 227	6 218	6 201	6 237
Customer numbers	316 818	322 742	327 190	331 100	337 050

Table 5.24 AER conclusion on growth forecasts—Powercor

	2011	2012	2013	2014	2015
Sum of coincident ZSSs (MW)	2 481	2 557	2 652	2 747	2 848
Energy consumption (GWh)	10 726	10 795	10 781	10 761	10 797
Customer numbers	717 745	731 603	745 570	759 343	772 544

Table 5.25 AER conclusion on growth forecasts—JEN

	2011	2012	2013	2014	2015
Sum of non-coincident ZSSs (MW)	1 099	1 130	1 161	1 192	1 212
Energy consumption (GWh)	4 334	4 322	4 271	4 222	4 205
Customer numbers	310 165	315 890	320 889	325 174	329 428

Table 5.26 AER conclusion on growth forecasts—SP AusNet

	2011	2012	2013	2014	2015
Sum of non-coincident ZSSs (MW)	1 874	1 959	2 046	2 130	2 219
Energy consumption (GWh)	7 975	7 978	7 961	7 974	8 042
Customer numbers	633 847	646 034	657 240	667 352	677 204

Table 5.27 AER conclusion on growth forecasts—United Energy

	2011	2012	2013	2014	2015
Sum of non-coincident ZSSs (MW)	2 359	2 424	2 495	2 576	2 591
Energy consumption (GWh)	7 936	7 964	7 905	7 842	7 836
Customer numbers	627 203	633 295	638 757	643 600	648 220

6 Outsourcing arrangements

Each of the Victorian distribution network service providers (DNSPs) significantly engage in outsourcing, with approximately two thirds of this outsourcing to contractors which are related to the Victorian DNSPs through common ownership. As a result, much of the Victorian DNSPs' operating and capital expenditure forecasts are based on the charges they expect to pay to these related party contractors.

The AER recognises the significant economies of scale and scope or other efficiencies that a DNSP may gain access to through outsourcing. At the same time, the AER also recognises that through outsourcing to related party contractors, a service provider may attempt to maintain its reported expenditure at an ‘artificially inflated’ level in order to influence their future expenditure allowances, increase their regulatory asset base, and retain the benefit of realised historical efficiencies for a prolonged or indefinite period of time rather then sharing the benefit of these efficiencies with consumers through lower prices.

In this chapter the AER considers the appropriate treatment of outsourcing arrangements in the context of the requirements of the National Electricity Law (NEL) and National Electricity Rules (NER), and taking into account the Victorian DNSPs' revised regulatory proposals and submissions from other stakeholders. The analysis and outcomes from this chapter are most directly applied to:

- the standard control services operating expenditure (opex) forecast in chapter 7, and
- the standard control services capital expenditure (capex) forecast in chapter 8

There is also a connection between the analysis in this chapter, and:

- the regulatory asset base (RAB) roll-forward in chapter 9
- the measurement of operating expenditure efficiencies in the current regulatory control period under the ESCV's efficiency carryover mechanism (ECM), and in the forthcoming regulatory control period under the AER's efficiency benefit sharing scheme (EBSS), in chapters 13 and 14, respectively, and
- the assessment of alternative control services (public lighting and other alternative control services) in chapters 19 and 20, respectively.

The term 'margin' in this chapter is used to reflect any difference between a contract price and a contractor's actual direct costs (that is, 'margins' may include corporate and other indirect costs, and profit margins).

6.1 Regulatory requirements

The National Electricity Rules (NER) provide that the AER must accept the forecast of required opex of a DNSP that is included in a building block proposal if the AER is satisfied that the total of the forecast opex for the regulatory control period reasonably reflects the opex criteria, namely:

- the efficient costs of achieving the opex objectives
- the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives, and
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[1]

The capex criteria, which apply to the assessment of capex forecasts, are analogous.[2]

If the AER is not satisfied that the forecast opex or forecast capex reasonably reflect the opex criteria or the capex criteria the AER must not accept the forecast. As noted in chapters 7 and 8, in deciding whether or not to accept the forecast the AER must have regard to the capex factors or the opex factors, as relevant. Of those factors, the following are particularly relevant to the assessment of outsourcing and related party transactions:

- the actual and expected opex or capex of the DNSP during any preceding regulatory control periods
- benchmark opex or capex that would be incurred by an efficient DNSP over the regulatory control period, and
- the extent the forecast of required opex or capex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm’s length terms.[3]

CitiPower, Powercor and JEN consider that the AER has misconstrued the efficiency and prudency criteria in the draft decision. This issue is addressed in section 6.5.3.5.

6.2 AER draft decision

6.2.1 Conceptual approach

In the draft decision, the AER noted that outsourcing to specialist providers of a particular service is a common means by which businesses in the economy are able to gain access to economies of scale and scope and other efficiencies. Accordingly, service providers should be provided with effective incentives to seek out efficient and prudent outsourcing and related party transactions.

At the same time, the AER recognised that an incentive exists for service providers to engage in related party transactions on non-arm's length terms, with the result that the service provider's reported expenditure might be artificially inflated, and that the benefits of efficiencies realised by the service provider and its related party contractors might be retained by their shareholders for a prolonged or potentially

1 National Electricity Rules, cl. 6.5.6 (c).
2 NER, cl. 6.5.7 (c).
3 NER, cl. 6.5.6 (d)–(e), 6.5.7 (d)–(e).

indefinite period, rather than being shared with consumers after a period of time. Accordingly, the AER considered outsourcing arrangements and related party transactions should be assessed closely against the requirements of the NER.

In the draft decision, in determining whether it was satisfied that those parts of the total forecast capex and forecast opex which represented outsourcing contract charges reasonably reflects meets the capex and opex criteria, the AER had regard to, among other matters, its own analysis. The analysis applied was primarily a conceptual framework which the AER developed, taking into account the Victorian DNSPs' proposals, the AER's previous approach in the JGN access arrangement draft decision, and the past regulatory debate on this issue.

The first stage of the conceptual framework is a 'presumption threshold' designed to be an initial filter to determine which contracts it is reasonable to presume reflect efficient costs that would be incurred by a prudent operator, and which contracts it is not reasonable to presume reflect efficient costs or costs that would be incurred by a prudent operator. In undertaking this 'presumption threshold' assessment, the AER considered the two relevant considerations to be:

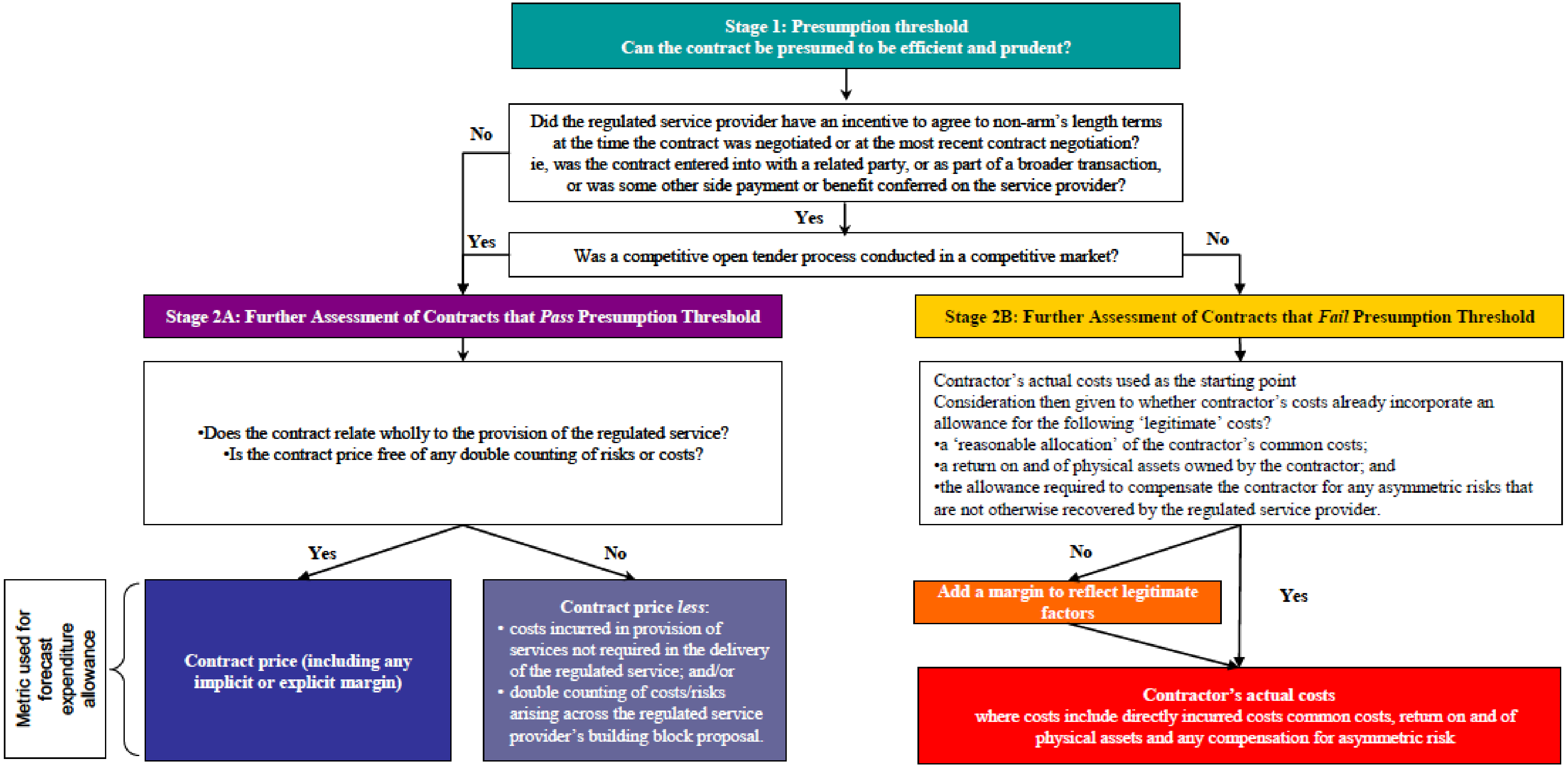
- Did the service provider have an incentive to agree to non-arm's length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

In the absence of an incentive to agree to non-arm's length terms, the AER considered it reasonable to presume a contract price reflects efficient costs. The AER also considered this presumption to be reasonable where an incentive to agree to non-arm's length terms existed but the contract was the outcome of a competitive open tender process in a competitive market.

Where an arrangement 'passes' the presumption threshold, the AER considered the starting point for setting future expenditure allowances should be the contract price itself, with limited further examination required. This further examination involves checking whether the contract wholly relates to the relevant services (e.g. standard control services) and whether the (efficient) contract price already compensates for risks or costs provided for elsewhere in the building blocks (e.g. debt raising costs).

Where a contract fails the presumption threshold, the AER considered the starting point for setting future expenditure allowances should be the contractor's actual costs itself, with a 'margin' above this level permitted only where the service provider is able to establish that such a margin is efficient and prudent against legitimate economic reasons for the inclusion of the margin (and its quantum).

Figure 6.1 AER—Draft decision approach to outsourcing and related party transactions



AER, *Draft decision*, pp.168-191.

6.2.2 Assessment of individual transactions

The AER identified some limited concerns with the tendering processes conducted by SP AusNet in its appointment of Tenix Alliance and by United Energy in its appointment of its 'turn key service provider' to replace JEN Asset Management. However, the AER still considered that these arrangements passed the presumption threshold and so the AER can presume these arrangements reflect efficient costs that would be incurred by a prudent operator. Both these arrangements are with parties who are not related to the service provider.

The related party margins of CitiPower, Powercor, JEN and SP AusNet did not pass the presumption threshold, and so the AER considered whether a margin above the related party's direct costs is appropriate. Two of the reasons the AER considers are legitimate economic reasons for the inclusion of a margin are to:

- compensate for a share of the contractor's corporate and other indirect costs, and
- retain the benefit of historical efficiencies for a period of time.

That said, the AER's assessment of the related party's corporate costs have already been included in the DNSP’s expenditure forecasts. In addition, the AER is seeking to reward the Victorian DNSP's for the historical efficiencies realised by their related parties through the efficiency carryover mechanism (ECM) allowance. Accordingly, no additional 'margin' in the expenditure forecasts is required to compensate the Victorian DNSPs for these historical efficiencies.

Additionally, the AER has identified some issues with the corporate costs of the related parties of JEN, SP AusNet and United Energy and has made adjustments to these costs. These issues include corporate costs not sufficiently connected to the provision of distribution services and management fees paid to parent companies that the AER is not satisfied are consistent with a total forecast capex or opex allowance which reasonably reflects the capex or opex criteria.

The other legitimate economic justification for a margin is to compensate for the return on and return of capital invested in assets utilised by the related party contractors, where those assets are not already in the service provider's regulatory asset base (RAB). The AER is not aware of the existence of such assets nor have the Victorian DNSPs, in their revised regulatory proposals, demonstrated that these assets exist. If such assets did exist, the AER considers allowing for a margin to compensate for the return on and return of those assets is consistent with a total forecast capex or opex allowance which reasonably reflects the capex or opex criteria.

6.3 Victorian DNSP revised regulatory proposals

6.3.1 CitiPower and Powercor

AER conceptual approach and assessment of individual arrangements

For the reasons set out in the draft decision, CitiPower and Powercor accepted the AER's decision to:

- exclude related party margins from the calculation of the efficiency carryover mechanism (ECM) amounts for the current regulatory control period
- include the related party margins in the regulatory asset base (RAB) roll-forward over the current regulatory control period, and
- exclude the administration fee payable by CitiPower and Powercor under the DRMS with CHED Services from their expenditure forecasts and the calculation of the efficiency benefit sharing scheme (EBSS) amounts for the forthcoming regulatory period.[4]

CitiPower and Powercor did not accept the AER's decision to exclude the margins payable under their contracts with related party contractors and their communications contracts with Silk Telecom:

- from their opex and capex forecasts for the forthcoming regulatory control period, and
- from the calculation of the EBSS amounts for the forthcoming regulatory control period.

CitiPower and Powercor did not recommend any changes to the AER's 'presumption threshold' (stage 1) or the AER's treatment of contracts that pass the presumption threshold (stage 2A).

However, CitiPower and Powercor considered that the AER's treatment of contracts that fail the presumption threshold (stage 2B)—specifically the treatment of economies of scale, scope and other efficiencies available to the contractor—is flawed, because:

- it is legally impermissible for the AER to adopt the costs that would be incurred by the group to which the DNSP belongs as a benchmark or counterfactual to assess expenditure forecasts against—properly construed and applied, the NEL and NER require the AER to adopt the stand-alone, in-house cost of service provision as the benchmark or counterfactual
- the AER's application of theory regarding pricing outcomes in a workably competitive market is erroneous, in particular the AER's assumption that the long run is any period in excess of a five year regulatory control period which is contrary to observed commercial practices and a prior Tribunal decision
- the AER's approach to scale, scope and other efficiencies:
  - does not recognise the potential for outsourcing arrangements that are deemed to fail the first stage 'presumption threshold' to be an efficient means of service delivery, and

[4] CitiPower, *Revised regulatory proposal*, p.121; Powercor, *Revised regulatory proposal*, p.113.

  - as a result, creates perverse incentives for DNSPs to bring their operations in-house where the outsourcing arrangement is a more efficient means of service delivery, and

- the AER's approach is inconsistent with previous regulatory decisions by itself and the ESCV.[5]

CitiPower and Powercor conceptual approach

To address what CitiPower and Powercor considered were the shortcomings of the AER's approach, they suggest stage 2B of the AER's framework be amended so that a contract that fails the presumption threshold is still considered to comply with the expenditure criteria:

> …where it can be demonstrated that the contract price is less than or equal to the in-house cost of provision, where the in-house cost of provision is measured by reference to the stand-alone counterfactual.[6]

CitiPower and Powercor stated this would bring the AER's framework into line with the approach taken by the ESCV in the GAAR.

They argued that one or more of the following types of evidence should be sufficient to provide this demonstration:

- documentary evidence from the time the contract was entered into that demonstrates that the DNSP considered whether the contract would lower its overall costs and that it weighed up the alternatives before entering into the contract

- information on the economies of scale, scope and/or other efficiencies that would be available to the contractor that would not otherwise be available to the DNSP, or

- evidence that demonstrates that if the DNSP undertook the activities itself the costs would be higher than the contract payments.[7]

Where a DNSP is unable to demonstrate this, CitiPower and Powercor stated the AER should utilise the in-house cost estimate in the derivation of forecast opex and capex.[8]

Other factors CitiPower and Powercor considered could inform the AER's assessment of contracts that fail the presumption threshold are an assessment of the contract's non-price terms and conditions and comparative benchmark analysis, though conceding that care must be taken in utilising benchmark analysis.[9]

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[5] CitiPower, *Revised regulatory proposal*, pp.136-137; Powercor, *Revised regulatory proposal*, pp.126-127.
[6] CitiPower, *Revised regulatory proposal*, p.148; Powercor, *Revised regulatory proposal*, p.138.
[7] CitiPower, *Revised regulatory proposal*, p.148; Powercor, *Revised regulatory proposal*, p.138.
[8] CitiPower, *Revised regulatory proposal*, p.149; Powercor, *Revised regulatory proposal*, p.138.
[9] CitiPower, *Revised regulatory proposal*, p.151; Powercor, *Revised regulatory proposal*, p.140.

6.3.2 Jemena Electricity Networks (Victoria)

AER conceptual approach

JEN argues that the AER's approach has a number of fundamental shortcomings which it characterises as relating to:

- a failure to recognise that while the parties involved in related party transactions may have an incentive to agree to an 'artificially inflated' price, a more detailed consideration of the contract price is required to determine whether the parties acted upon the incentive
- the AER's treatment of efficiencies available to the contractor (arising from its interpretation of the prudency criterion and workably competitive market hypothesis), which is inconsistent with:
  - the original intent of the provision 'prudent operator in the circumstances of the relevant DNSP'[10]
  - clauses 6.5.6(b)(2) and 6.5.7(b)(2) of the NER relating to the consistency of a DNSP's expenditure forecasts with its cost allocation method
  - prior regulatory decisions by the AER, the ESCV and the Tribunal
  - other aspects of the AER's draft decision
  - commercial evidence of the margins earned by contractors
- the reliance placed by the AER on the EBSS to be used to reward a contractor for efficiencies achieved during the regulatory control period
- the inconsistency of the current position taken by the AER on the margins payable under the related party contracts with the position it has taken in both the ActewAGL and the JGN final decisions.[11]

JEN argues one of the more fundamental shortcomings of the AER's approach is that it fails to recognise the potential for an outsourcing contract that cannot be presumed to be efficient to be nevertheless a genuinely efficient outcome. JEN submits that the AER's approach assumes unreasonably that the DNSP will be able to access the same economies of scale, scope and other efficiencies that would be available to a contractor that provides services to any number of related and unrelated parties.[12]

JEN also argues that:

- the practical effect of this assumption is that an outsourcing contract that fails the presumption threshold will never be viewed as a more efficient means of delivering a service than the DNSP providing the services in-house, and

[10] The AER notes that JEN mistakenly quotes this provision as 'prudent operator in the relevant circumstances of the DNSP'.
[11] JEN, *Revised regulatory proposal*, pp.84-85.
[12] JEN, *Revised regulatory proposal*, p.85.

- the consequence is that DNSPs will have a perverse incentive to provide services in-house even where outsourcing is a more efficient outcome because the DNSP cannot access the same efficiencies as the contractor.[13]

Additionally, JEN argues that:

- in the longer term, users will bear the costs associated with inefficiently bringing services in-house, and
- in the short to medium term, the AER's framework could result in those DNSPs that have entered into contracts that fail the presumption threshold:
  - not recovering at least the efficient costs they incur, which could result in an inefficient level of asset utilisation
  - being accorded insufficient incentives to promote economic efficiency, and
  - under-investing in their distribution networks[14]

JEN states that such an outcome would be contrary to several revenue and pricing principles and inconsistent with the NEO.[15]

JEN conceptual approach

JEN does not recommend any amendments to stage 1 or 2A of the AER's framework. Similar to CitiPower and Powercor, JEN proposes the AER's assessment of contracts that fail the presumption threshold (stage 2B) be modified to bring it into line with the approach adopted by the ESCV in the GAAR. Using the same words as CitiPower and Powercor, JEN proposes:

> Specifically, the framework should be modified to recognise the potential for the contract price to still be consistent with the operating and capital expenditure criteria in the Rules, where a DNSP is able to demonstrate that the contract price is equal to or lower than the costs that would be incurred if the services were provided in-house, where the in-house cost of provision is calculated by reference to the stand-alone counterfactual.[16]

JEN argues that if a DNSP is able to demonstrate that this is the case, then, in the absence of further evidence or material, the contract price should form the basis for:

- the DNSP's forecast operating and / or capital expenditure, and
- the measurement of operating expenditure used in the EBSS.[17]

If a DNSP is unable to demonstrate this is the case then, consistent with CitiPower's and Powercor’s proposed framework, the in-house cost estimate should form the basis of the expenditure forecasts.

[13] JEN, *Revised regulatory proposal*, p.85.
[14] JEN, *Revised regulatory proposal*, pp.85-86.
[15] JEN, *Revised regulatory proposal*, p.86.
[16] JEN, *Revised regulatory proposal*, p.86.
[17] JEN, *Revised regulatory proposal*, p.86.

JEN proposes that the contractor's direct costs be used as the starting point for estimating the cost of in-house provision, with additional allowances added to reflect:

- the return on and of assets required by the contractor for those assets that it owns and are used in the provision of services to the DNSP
- an appropriate portion of the contractor's common costs, and
- the economies of scale, scope and other efficiencies not otherwise available to the DNSP operating on a standalone basis.[18]

JEN considers that while ascribing a value to the first two of these items will be relatively straightforward, in practice it may not be possible to quantify, with any degree of precision, the value of efficiencies that are available to the contractor but not otherwise available to the DNSP. Accordingly, JEN proposes that one alternative the AER could use to satisfy itself when assessing whether the contract price is likely to be less than the in-house cost of provision is, where the contract is based on a cost pass through pricing structure, to undertake an inquiry to determine whether:

- the contractor's costs (both directly and indirectly incurred and an appropriate share of common costs) are lower than those that could be achieved by the in-house service provider operating on a stand alone basis, and
- the margin (defined in this context as an amount in excess of the contractor's directly and indirectly incurred costs and an appropriate share of common costs) is comparable to that charged by other contractors for similar levels of risk and does not exceed the expected benefits of the economies of scale, scope and other efficiencies offered by the contractor.[19]

JEN states the results of benchmark studies may provide further support for this inference where an outsourcing arrangement accounts for a substantial proportion of a DNSP's total expenditure. While conceding that benchmarking can not, in and of itself, be relied upon to demonstrate consistency with the opex and capex criteria. [20]

Other factors that JEN states would be relevant are the contract's non-price terms and conditions and incentive arrangements.[21]

Assessment of related party contractor's corporate costs

JEN accepted the AER's exclusion from its opex forecast of the management fee paid from Jemena Ltd to Singapore Power. However, JEN did not accept the AER's exclusion of Jemena Ltd's corporate strategy costs.

[18] JEN, *Revised regulatory proposal*, pp.86-87.
[19] JEN, *Revised regulatory proposal*, p.87.
[20] JEN, *Revised regulatory proposal*, p.87.
[21] JEN, *Revised regulatory proposal*, p.88.

6.3.3 SP AusNet

AER conceptual approach and assessment of individual arrangements

Given the common ownership between SP AusNet, SPI Management Services (SPIMS), Enterprise Business Services (EB Services) and SPI (Australia) Assets (SPIAA), in the draft decision the AER stated it could not presume the contracts SP AusNet had with these related parties were efficient.

In response to the AER's application of its presumption threshold to its related party transactions, SP AusNet states while each of these related parties are 100 per cent owned by Singapore Power, SP AusNet is only 51 per cent owned by Singapore Power. SP AusNet stated that it:

> … disagrees with the Draft Determination in that from an ownership perspective, there is NO incentive to agree to non-arm's length terms.[22]

[text removed c-i-c]

On the AER's approach to contracts that fail the presumption threshold, SP AusNet accepts the AER's position on what are the legitimate economic reasons that justify a margin above direct costs. For example, SP AusNet:

> …accepts the Draft Determination's position that the regulatory regime provides a 'return on capital' building block allowance in place of a 'profit margin', thus a profit margin in a contract with a related party can only be justified to the extent the related party utilises assets not already in the service provider's Regulatory Asset Base (RAB).[23]

On the AER's treatment of economies of scale, scope and other efficiencies available to a related party contractor that operates multiple networks, SP AusNet:

> …agrees that a hypothetical 'fully in-sourced' network model is not appropriate in assessing expenditure forecasts given the circumstances of the DNSPs.[24]
>
> …accepts the Draft Determination's approach to operating and capital expenditure in relation to the treatment of efficiencies.[25]

Assessment of related party contractor's corporate costs

SP AusNet states that while the AER willingly accepts the scale, scope and other efficiencies of being part of a larger group delivers to the DNSP, it seems reluctant to accept the overheads that also might be incurred.[26]

Specifically, SP AusNet rejects the draft decision's:

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[22] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.9.
[23] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.12.
[24] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.13.
[25] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.12.
[26] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.11.

- exclusion of the Singapore Power management fee—on the basis that the fee was not included in SP AusNet's expenditure forecasts to begin with, and

- re-allocation of SPIMS' corporate costs—on the basis that the AER's consideration of SP AusNet's whole of business costs is an irrelevant consideration, is not captured under one of the opex factors, and is inconsistent with the NEO and revenue and pricing principles. Further, SP AusNet argues that it has already returned some efficiencies to consumers, it does not have an incentive to allocate costs inefficiently given the application of the EBSS, the AER's approach results in scale or synergy gains being passed through immediately to consumers, the AER's use of percentages instead of actual amounts is flawed, and that any errors introduced by SP AusNet's approach is not significantly material and is transitory in nature.[27]

SP AusNet's revised proposal includes the same SPIMS' costs as its initial proposal.[28]

6.3.4 United Energy

AER conceptual approach

United Energy does not provide any specific comments on the approach outlined in the draft decision but states it is well aware that the regulatory treatment of profit margins for services provided by related parties is a contentious issue. It notes the regulatory issues regarding related party contracts was one reason it decided to adopt a new business model based on competitively tendered outsourced service providers.[29]

Assessment of individual arrangements

In response to the AER's assessment of its recent tendering process, United Energy states:

- the market testing process was highly competitive, as borne out by the strong commitment of bidders, and has confirmed the market's appetite for United Energy's new business model

- under the operating services agreement (OSA), United Energy may, but is not obliged to, put a 'match' offer from a single service provider for all the services for a five year term to JAM. The market testing exercise has not triggered this right, and

- United Energy does not intend to require a new service provider or providers to take an equity stake in United Energy.[30]

In response to the AER's assessment of its JAM contract and consequent counterfactual cost build-up based on United Energy's current business model, United Energy:

[27] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.13-25.
[28] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.15, 25.
[29] United Energy, *Revised regulatory proposal*, p.80.
[30] United Energy, *Revised regulatory proposal*, .pp.19-20.

- disagrees with the AER's adoption of JAM's actual costs in setting the base opex forecast without adding a profit margin on top of these costs[31]—submitting a report from Frontier Economics in support of this position, and

- contends that a [c-i-c] on top of JAM's actual costs would be reasonable[32]—submitting a report from Ferrier Hodgson, used by United Energy in its AMI submission, in support of this position.

Assessment of related party contractor's corporate costs

United Energy accepts the AER's criticism that its initial regulatory proposal did not provide sufficient explanatory information regarding the services that are provided by AMPCI and DUET.[33]

In relation to these AMPCI and DUET costs, United Energy's revised proposal includes:

- a report from KPMG concluding that the services provided by AMPCI under the financial services agreement are not covered by the debt raising cost allowance, and are instead day to day treasury management and general financial services

- a report from KPMG concluding that the services provide by DUET necessary for United Energy and that the amount of the fees are efficient

- a letter from DUET detailing the services its to United Energy

- an audit opinion from Ernst & Young confirming the costs incurred by United Energy from services provided by AMPCI and DUET, and

- a report from KPMG confirming that the AMPCI and DUET costs relate to the provision of standard control services, properly fall under the definition of operating expenditure in the NER, and do not constitute a 'double-counting' with other regulatory allowances

United Energy concludes that the services provided by AMPCI and DUET are appropriately incurred in the provision of standard control services.[34]

6.4 Submissions

6.4.1 Energy Users Coalition of Victoria

The Energy Users Coalition of Victoria (EUCV) states that a major risk for consumers is that a DNSP uses its related parties to provide some of the services required in the provision of services. By their very nature, the EUCV considers related party transactions cannot be demonstrated to be the most efficient arrangement.[35]

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[31] United Energy, *Revised regulatory proposal*, p.80.
[32] United Energy, *Revised regulatory proposal*, p.81.
[33] United Energy, *Revised regulatory proposal*, p.66.
[34] United Energy, *Revised regulatory proposal*, p.68.
[35] Energy Users Coalition of Victoria (EUCV), *Submission to the AER—2010 AER review of Victorian electricity DBs—EUCV response to AER draft decision, August 2010*, p.1.

The EUCV considers the most efficient outsourcing outcome is where the outsourcing is competitively tendered. [36]

It considers that outsourcing is only more efficient when the costs of outsourcing plus the margin is less than the cost of carrying out the work internally. The EUCV states DNSPs have consistently failed to provide clear evidence of this. It responds to the consultants reports submitted by some of the Victorian DNSPs by stating:

> …great care needs to be taken in assessing the independence of such reports. The EUCV comments that there is a world of difference between a consultant's report giving a view as to an "arms length" view of the costs of an activity, to a contractually binding firm offer to carry out an agreed scope of work made in competition with other qualified contractors.[37]

Overall, the EUCV considers the AER has made a detailed and in-depth assessment of the issue of related party transactions and the impact of these on assessing efficient costs for opex and capex. Whilst the EUCV is not convinced that consumers are effectively paying a premium so that the DNSPs and their owners can garner increased profits, there is significant difficulty in proving either way whether this concern is substantial.[38]

On balance, the EUCV considered that the AER approach is likely to achieve a minimum of cost premium for consumers and therefore considers the outcome of the AER approach is a sound attempt to resolve this aspect.[39]

6.4.2 Minister for Energy and Resources

The Minister for Energy and Resources (the Minister) considers that in the draft decision the AER has undertaken considerable analysis with respect to outsourcing and related party transactions to assess the Victorian DNSPs' operating and capital expenditure forecasts. Notwithstanding the detailed analysis, the Minister notes the AER has not sought to make adjustments to the DNSPs' roll forward calculations with respect to related party margins.[40]

The Minister notes the AER has reached this conclusion through its interpretation of clause S.6.2.1(e)(1) of the NER. The Minister states the AER (rightly) has expressed considerable concern about its conclusion based on this interpretation and pointed to the need for changes to the NER. However, the Minister considers the interpretation that the AER has reached is not, in terms of a purposive interpretation of the NER consistent with the NEO, correct.[41]

The Minister argued to protect the long term interests of consumers, consistent with the NEO, the AER should only increase the RAB by the capex incurred in providing standard control services and not for the related party margins that are not justified.[42]

[36] EUCV, *Submission to the AER*, 19 August 2010, p.42.
[37] EUCV, *Submission to the AER*, 19 August 2010, pp.42-43.
[38] EUCV, *Submission to the AER*, 19 August 2010, p.43.
[39] EUCV, *Submission to the AER*, 19 August 2010, p.43.
[40] Minister for Energy and Resources, *Submission on the Victorian Electricity Distribution Network Service Providers' regulatory proposals for 2011-2015*, 20 August 2010, p.1.
[41] Minister for Energy and Resources, *Submission to the AER*, 20 August 2010, pp.1-2.
[42] Minister for Energy and Resources, *Submission to the AER*, 20 August 2010, p.4.

The AER has responded to the Minister's submission in chapter 9 which deals with the roll forward of the RAB.

6.5 Issues and AER considerations—Conceptual approach

In this section the AER responds to the Victorian DNSPs' revised regulatory proposals and submissions in relation to assessing contract charges paid under outsourcing arrangements. This is part of the AER determining whether it is satisfied the total of the Victorian DNSPs' proposed forecast opex and capex reasonably reflects the opex and capex criteria. In particular, this section responds to issues raised in relation to:

- the AER's approach to assessing outsourcing arrangements, consisting of
  - stage 1—Presumption threshold (section 6.5.1)
  - stage 2A—Assessments of contracts that 'pass' the presumption threshold (section 6.5.2)
  - stage 2B—Assessment of contractors that 'fail' the presumption threshold (section 6.5.3), and
- the approaches proposed by the Victorian DNSPs in their revised regulatory proposals (6.5.4)

and in the context of related party transactions, considers:

- the appropriate emphasis to be placed on different types of benchmarking (section 6.5.5)
- implications for rolling forward the RAB (section 6.5.6)
- implications for measuring operating efficiencies under the EBSS (section 6.5.7), and
- implications for the assessment of alternative control services (section 6.5.8)

6.5.1 Stage 1—Presumption threshold

6.5.1.1 AER draft decision

The AER considered it was appropriate, as an initial ‘filter stage’, to determine which contracts it is reasonable to presume reflect efficient costs and costs that would be incurred by a prudent operator. Applying the ‘presumption threshold’ involves asking the following two relevant questions:

- Did the service provider have an incentive to agree to non-arm’s length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

In the absence of an incentive to agree to non-arm's length terms, the AER considered it was reasonable to presume the contract price reflects efficient costs and the costs incurred by a prudent operator. This presumption was also considered reasonable where an incentive to agree to non-arm's length terms exists, however the contract must have been subject to a competitive open tender process in a competitive market.

Question one: Did the service provider have an incentive to agree to non-arm's length terms at the time the contract was entered into (or at its most recent re-negotiation)?

Generally, the regulatory regime encourages service providers to seek out efficiencies and minimise costs (particularly in relation to opex). However, the AER noted some instances where a service provider has an incentive to outsource services on non-arm's length terms (that is, at an inefficient or artificially inflated price). The AER considered the main examples of this include:

- where the outsourcing contract is with a related party
- where the outsourcing contract is not determined independently from the negotiations of some other contract or arrangement
- where some other side-payment or benefit is conferred on the service provider in exchange for accepting an artificially inflated price

The AER noted that the second and third examples could occur between the service provider and either a related or non-related party contractor.

Outsourcing contract is with a related party

Where a service provider outsources activities to a related party then the incentive to minimise the cost of the outsourcing (and only to outsource if it leads to lower costs) is reduced. This occurs given the value of the contract charge has no financial effect on the ultimate owner (as the higher or lower cost to the service provider perfectly corresponds with a higher or lower revenue of the related party) where the ownership of both parties is identical. Indeed, if there is an expectation that the regulatory regime or the regulator may permit the higher contract price to be ultimately factored into regulated charges, then there is an incentive to agree to a higher price than otherwise would be the case for the outsourced activities (and possibly also to outsource when it may not reduce cost). If the regulator accepts the non-arm's length or inflated contract price, the service provider continues to recover its full costs while the related party earns inflated profits which can be passed on to its shareholders (being the same shareholders as the service provider).

However, where an investor is a majority shareholder in a service provider but only a minority shareholder in its related party contractor, then the service provider may not have an incentive to agree to non-arm's length terms. This is because the majority shareholder's portion of the profits (or value) that are transferred out of the service provider is greater than its share of the profits that are transferred to the related party. In other words, the transfer of profits from the service provider to the related party results is a net loss for the service provider's majority shareholder unless it is also a majority shareholder in the related party who receives those inflated profits through transfer pricing.[43]

The draft decision noted that the importance of considering the incentives of the parties was consistent with past regulatory practice, including that of the ESCV and the views of the appeal panel in the 2006 EDPR. It stated that there appeared to be broad agreement among regulators, service providers and economic consultants that looking at whether a perverse incentive to agree to non-arm's length terms existed at the time a contract was negotiated was a relevant consideration in the assessment of outsourced contracts.[44]

Outsourcing contract is not negotiated independently from other negotiations

The AER considered that where negotiations over an outsourcing contract are not determined independently from the negotiations for some other contract or arrangement, then a service provider may not have an incentive to minimise the cost of the first contract. This is because the price that the service provider is willing to pay under the first contract will depend on the price it pays or receives under the second contract. To generalise the point, the service provider may agree to an artificially inflated or non-arm's length contract price in exchange for some other side-payment or benefit conveyed on it (or on its parent, subsidiary or shareholders). These situations could arise regardless of whether the parties are related by common ownership or not.[45]

Question Two: Was a competitive open tender process conducted in a competitive market?

The draft decision noted that the position that a competitive tender can provide assurance as to the efficiency of a contract price (and sometimes only a competitive tender) was also a common feature of past regulatory practice in relation to the assessment of outsourcing contracts with related parties.[46]

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[43] The draft decision noted that this recognition differs from the ESCV's past practice where United Energy argued that the ESCV did not appreciate the relevance of the difference between controlling and non-controlling shareholders. Though the AER also noted that, even in this circumstance, the service provider's majority shareholder may permit the service provider to agree to non-arm's length terms if it receives some other side-payment or benefit from the contractor in exchange for agreeing to the inflated contract price.

[44] The AER noted that some of the preferred terminology differed between parties. For example, NERA considers the use of the term 'related party' is unhelpful considering the various definitions applied to the term by accountants, lawyers and regulators. In its place, NERA prefers to ask if the parties were acting as a 'single economic entity' stating that this term is commonly used in the US in relation to anti-trust cases. The AER did not disagree with NERA's preferred terminology, and considered the differing terminology used to consider the incentive issue resulted in substantially similar if not the same outcomes.

[45] The AER noted that a possible circumstance where this may arise in a regulated setting includes where a service provider divests assets or a part of its operations (that is, its field services staff and associated equipment and vehicles) and enters into an agreement with the party who bought those assets to provide services back to it. The equity value that the service provider would be willing to accept for its divested operations will be dependant on the contract price that it pays the acquiring party for the operating services agreement they enter into.

[46] The AER noted that the ESCV explicitly included a competitive tender process criterion in its EDPR and implicitly in the GAAR (generalising it to circumstances surrounding the negotiation of the contract). ACG considered it important and included it before the incentive criterion, however NERA did not include a competitive tender process criterion is its framework (and so presumably

The AER recognised that there may be limited instances where competitive tendering is impracticable, perhaps due to a shortage of suitable contractors who would be likely to submit an offer or because the cost of the tendering process outweighs the price discovery benefits of this process. In the absence of an incentive on the service provider to agree to non-arm's length terms, the AER considered it was reasonable to assume that a service provider's decision whether or not to conduct a competitive open tender will likely be the result of its assessment of the benefits and costs of such a process. Accordingly, the AER considered that it was reasonable to presume a contract reflects efficient costs where a service provider does not have an incentive to accept an artificially inflated or non-arm's length contract price, even where the contract has not been procured via a competitive tender. In such a circumstance, the AER has not identified any economic reasons to suggest that the service provider would not be seeking to achieve the best value it can from the negotiation with the third party contractor, in accordance with the positive cost-minimising incentives in the regulatory regime. Nonetheless, where a tender had been undertaken, the AER stated this would provide it with an added level of assurance that the contract is priced efficiently.

In contrast, where an incentive on the service provider to accept non-arm's length terms exists, the AER stated that the means by which the contract price was determined becomes important. In the presence of such an incentive, the AER considered it should not presume the contract reflects efficient costs or the costs incurred by a prudent operator unless that contract has been subjected to a competitive open tender in a competitive market.

The AER noted the Water Services Regulation Authority (Ofwat) also considered that competitive tendering was the only means of testing that provides an objective view as to whether a contract price is efficient. Ofwat considered that other forms of 'market-testing' (e.g. benchmarking) tend to require the use of judgement in comparing a predetermined price with the market, as a means of justifying the original price. Whereas competitive tendering avoids this problem as it inherently discovers the market price without inference in or judgement of the market.[47]

Additionally, the AER considered that for a contract to pass the presumption threshold, the tender process should be conducted in a competitive market. In the absence of this criteria, a service provider may attempt to 'bundle' together a large and disparate group of services in such a way that it would be unlikely to receive many tender proposals—except from its related party or parties—and yet claim the contract had been 'market-tested'.[48]

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did not consider it important). NERA (Tom Hird) included a competitive tender process criterion in its framework but considered the 'are the services provided in a competitive market?' test from the EDPR—which was distinct from the 'has an arm's length open tender process been conducted?'—should be removed as it unfairly penalises service providers who, through no fault of their own, happen to be forced to pay monopoly rents to input providers.

47 Ofwat, *Regulatory accounting guideline 5.04—Guideline for transfer pricing in the Water Industry*, March 2005, p. 11.

48 The AER's addition of the '…in a competitive market' criteria is similar to that adopted by the ESCV in the EDPR 2006. However, the ESCV adopted the question, 'Are the services provided in a competitive market?' as its first decision box (with a 'yes' result leading to the second decision box and a 'no' leading to the conclusion that the 'underlying costs are relevant' for setting the expenditure allowances). The AER's approach effectively removes this question as

To assess whether the contract has been subjected to a competitive open tender process in a competitive market the AER considered it was relevant to assess the services provided under the contract, the tender process followed at the time the contract was negotiated, and the evaluation of competing tenders undertaken by the service provider.

6.5.1.2 Victorian DNSP revised regulatory proposals

The alternative assessment CitiPower and Powercor proposed as part of their revised regulatory proposals adopts the AER's presumption threshold without modification.[49]

In response to the AER's application of its presumption threshold to SP AusNet's related party transactions, it states while each of these related parties are 100 per cent owned by Singapore Power, SP AusNet is only 51 per cent owned by Singapore Power. It states that:

- any decisions affecting the costs incurred by SP AusNet have a material impact on the return to the minority shareholders whose position needs to be considered and carried, and
- as a listed company, SP AusNet has to comply with the ASX Corporate Governance Council's principles of good corporate governance and best practice recommendations and thus has to comply with strict corporate governance in relation to related party transactions.[50]

Accordingly, SP AusNet states that it:

> … disagrees with the Draft Determination in that from an ownership perspective, there is NO incentive to agree to non-arm's length terms.[51]

JEN and United Energy did not comment on the presumption threshold.

6.5.1.3 Submissions

As noted above, by their very nature, the EUCV considered related party transactions cannot be demonstrated to be the most efficient arrangement.

6.5.1.4 Issues and AER considerations

SP AusNet appears to have misrepresented the nature of the ASX Corporate Governance Council's ('the Council's) principles of good corporate governance and best practice recommendations. Following the Council's recommendations is not mandatory.

Rather, under the ASX's listing rules, companies are required to provide a statement in their annual report disclosing the extent to which they have followed the recommendations in the reporting period. Where companies have not followed all the

the ESCV's first decision box and combines it with the AER's second question (the ESCV's third) regarding open tender processes.

[49] CitiPower, *Revised regulatory proposal*, pp.148-150; Powercor, *Revised regulatory proposal*, pp.137-140.

[50] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.8-11.

[51] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.9.

recommendations, they must identify the recommendations they have not followed and give reasons for not following them. The Council refer to its corporate governance framework as a 'if not, why not' framework that relies on disclosure rather than 'black letter' requirements.[52]

Accordingly, SP AusNet is not bound to follow the Council's recommendations, as SP AusNet represents in its revised proposal.

The AER is not able to assess the impact following or not following the Council's principles of good corporate governance has on the efficiency or prudence of contracts between SP AusNet and its related party contractors.

The AER notes SP AusNet's statement that any decisions affecting the costs incurred by SP AusNet have a material impact on the return to the minority shareholders whose position needs to be considered and carried.

Given SP AusNet is majority owned by Singapore Power, and the non-independent status (due to their connection with Singapore Power) of SP AusNet's chairperson and majority of directors, the AER considers it should not *presume* that SP AusNet's arrangements with related party contractors that are 100 per cent owned by Singapore Power have been negotiated on arm's length terms, therefore resulting in little further scrutiny of these arrangements.

That said, under the AER's framework where a contract is not presumed to reasonably reflect efficient costs does not mean that a margin above direct costs contained in the contract would necessarily be disallowed. Rather, failing the presumption threshold means the contract is subject to greater scrutiny with any margin contained requiring justification against legitimate economic reasons for the inclusion and magnitude of the margin.

Whilst SP AusNet might consider its related party contracts should pass the presumption threshold (a position the AER disagrees with), as SP AusNet supports the AER's legitimate reasons for a margin above direct costs, there should be limited areas of disagreement between SP AusNet and the AER in the AER's application of its stage 2B (assessment where contracts fail the presumption threshold) to SP AusNet's arrangements with SPIMS, EB Services and SPIAA.

The AER does not agree with the EUCV's view that related party transactions cannot, by their very nature, be demonstrated to be the most efficient outcome. While the AER considers related party transactions cannot be *presumed* to be efficient, if the inclusion and quantum of a margin in a related party transaction is substantiated against legitimate economic reasons for a margin, then the contract would be demonstrated as an efficient outcome.

6.5.1.5 AER conclusion

The AER considers the 'presumption threshold' from its draft decision remains an appropriate filter to distinguish between contracts that it is reasonable to presume

[52] ASX Corporate Governance Council, *Corporate governance principles and recommendations—2nd edition*, August 2007, pp.5-6.

reflect efficient costs and the costs of a prudent operator, and contracts that it is not reasonable to presume reflect such costs.

6.5.2 Stage 2A—Assessment where contract passes the presumption threshold

6.5.2.1 AER draft decision

Where a contract ‘passed’ the presumption threshold, the AER considered it was reasonable to presume the contract price (including any associated margin above direct costs) reflected efficient costs and the costs that would be incurred by a prudent operator in the circumstances of the relevant services provider. This was to be the case regardless of whether the contract is with a related or non-related party.

Accordingly, where a contract passed the presumption threshold, the AER considered it appropriate to use the contract price as the ‘starting point’ for setting the future expenditure allowances, however the contract price itself should not be used without the further assessment of two issues. Those were:

- an examination of whether the contract wholly relates to the provision of the relevant service (e.g. standard control services), and
- an examination of whether there is any ‘double-counting’ of risks or costs between the contract price and other elements of the building block proposal.

The AER considered that an examination of whether the contract relates wholly to the provision of the relevant service is a necessary step to ensure forecasts are set on an appropriate basis. The AER noted this step has been applied in previous regulatory approaches.

Where a contract relates to additional services, the AER noted that NERA Consulting considered this sufficient reason to require a comparison of the contract price with a separately derived estimate of the cost of service provision.

However, the AER considered a more practical approach was to allocate a portion of the contract price to those other services, with that allocation based on a causation approach, or if a causation approach can not be derived, a well accepted cost allocation approach. For electricity network service providers, this may involve following its approved cost allocation methodology (CAM).

The other examination was to ensure there is no ‘double-counting’ of certain risks or costs between the contract price and other elements of the building block proposal.

Reasons put forward to justify the inclusion of margins in contracts above direct costs include that the margin:

- reflects the transfer of risk (for example, systematic or asymmetric) to the contractor, or
- reflects an allowance for working capital.

The AER acknowledged that an efficiently priced contract may include a margin to compensate for these issues. However, the AER considered that even with an efficiently priced contract it does not automatically follow that the contract price in addition to the other elements of a service provider's particular building block proposal result in an overall revenue requirement that reflects efficient costs. This was because of the possibility of a 'double-counting' of certain risks or costs between the contract price and other elements of the building block proposal.

Where there is double-counting, the AER considered an adjustment would need to be made to either the contract price or the other building block element (depending on which is more practical) to remove the extent of the double-counting.

The AER noted that this further assessment of 'double-counting' even where a contract is presumed efficient has to some degree been noted in previous regulatory approaches. The AER noted an example provided by the Allen Consulting Group (ACG) that related to outsourcing and the cost of capital.[53]

The draft decision included the following table which highlighted possible instances of such 'double-counting' and the appropriate regulatory treatment.

[53] ACG, *GAAR—Outsourcing by regulated businesses—Statement of Jeffery John Balchin*, 22 August 2007, p. 12.

Table 6.1 AER draft decision—Instances of possible double counting of risks or costs between an (efficiently presumed) contract price and other elements of the building block proposal

Instances of possible 'double-counting'	AER response
Has there been a transfer of risk to the contractor without a commensurate reduction in risk compensation in other elements of the building block proposal?	**Asymmetric risk** Asymmetric risk may be fully or partially transferred to a contractor (e.g. under a fixed price contract) yet the service provider may seek a separate self insurance allowance and / or contingency allowance in its proposal resulting in a ‘double-counting’ of these risks. Depending on what is more practical in the instance, the AER would need to either adjust the contract price downwards or adjust the self insurance allowance / contingency allowance proportionately with the transfer of risk. **Systematic risk** Systematic risk may be partially transferred to the contractor. Given the benchmark basis on which the weighted average cost of capital (WACC) is set, adjusting the WACC downwards may be impractical (though the NER does allow different WACC parameters for different ‘classes’ of service provider). Accordingly, the AER may attempt to adjust downwards the contract price (though the AER acknowledges that this may also involve practical difficulties).
Do the services provided under the contract include cost categories that the service provider is also seeking an allowance for elsewhere in its proposal?	**Specific cost categories** For example, a contract may provide for the provision of insurance or debt raising costs, while the service provider also seeks these costs through an additional and separate allowance in its regulatory proposal. Depending on what is more practical in the instance, the AER would need to either adjust the contract price downwards or exclude the separate allowance sought to the extent of the overlap. **Working capital** A contract may provide for a working capital allowance (either directly or indirectly through the margin). However, the cash flow timing assumptions in the PTRM implicitly and fully compensate for working capital. Accordingly, working capital should not also be compensated for through the opex and capex allowances (i.e. through a contract price).

Source: AER, *Draft decision*, p.176.

6.5.2.2 Victorian DNSP revised regulatory proposals

CitiPower stated that:

…CitiPower finds it somewhat peculiar that the AER applies theory regarding pricing outcomes in workably competitive markets in its second stage assessment but has not sought to apply the same line of logic to those contracts that are deemed to pass the 'presumption threshold'. In particular, the AER has not sought to exclude any margin in excess of overheads and a return on and of capital invested in physical assets from expenditure forecasts to be incurred under these contracts. If the AER were genuinely of the view that, in a workably competitive market, a contractor would not be able to earn a margin referable to scale, scope or other efficiencies realised by the contractor for periods exceeding the duration of a 5 year regulatory period, it would have excluded from DNSPs' expenditure forecasts any margins in excess of overheads and a return on and of capital invested in physical assets that are payable under those outsourcing arrangements that pass the 'presumption threshold'.[54]

Powercor made an analogous statement in its revised proposal.[55]

That said, CitiPower or Powercor did not propose any changes to stage 2A of the AER's framework.[56]

JEN notes that in the draft decision the AER raised the possibility of a 'double-counting' of systematic risk between a contract price and the WACC, though acknowledged that adjusting either to remove the double-counting may be difficult in practice. In response, JEN states:

JEN agrees with the AER that any attempt to quantity the effect of an outsourcing arrangement on the systematic risk of a DNSP, and the adjustments that would be required to be made to either the contract price or the DNSP's WACC, is likely to pose a number of significant challenges. Some consideration was given to this issue by NERA in a report prepared for Envestra in 2007 entitled *Outsourcing by regulated business*. The clear conclusion emerging from this report was that any attempt to adjust the WACC to reflect changes in systematic risk would be a complex task and should not be embarked upon lightly by a regulator.

JEN agrees with the conclusions reached by NERA on this issue and therefore cautions the AER against employing either method before a more fulsome consideration of the issue is undertaken.[57]

SP AusNet and United Energy did not comment on the AER's approach to assessing contracts that pass the presumption threshold.

6.5.2.3 Issues and AER considerations

In response to CitiPower's and Powercor's comments, the AER reaffirms its view that in a workably competitive market a contractor could not retain the benefit of scale, scope of other efficiencies indefinitely.

The AER is conscious of the costs of regulation and the need to ensure that the AER's information gathering and approaches to assessment do not place a greater burden on DNSPs than is necessary. This was one impetus behind the AER's adoption of a

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54 CitiPower, *Revised regulatory proposal*, p.142.
55 Powercor, *Revised regulatory proposal*, p.132.
56 CitiPower, *Revised regulatory proposal*, pp.148-150; Powercor, *Revised regulatory proposal*, pp.137-140.
57 JEN, *Revised regulatory proposal*, pp.96-97.

'presumption threshold', where the AER could *presume* from a set of circumstances that a DNSP's outsourcing contract reasonably reflects efficient costs and the costs of a prudent operator without the imposition of an intrusive assessment process. For contracts that pass the presumption threshold, the AER considers it can rely on the competitive pressures between entities with an incentive to only agree to arm's length terms or the competitive rivalry between firms competing with each other through a tender process in a competitive market to ensure that the benefits from scale, scope and other efficiencies available to the contractor are eventually passed through to the DNSP and consumers in an appropriate timeframe. Accordingly, the AER considers the additional assessment suggested by CitiPower and Powercor to be unnecessary.

That said, the AER notes that CitiPower and Powercor did not propose any changes to stage 2A of the AER's framework, which it has applied without modification in the alternative assessment framework proposed by CitiPower and Powercor in their revised proposals.[58] Accordingly, CitiPower's and Powercor's comments appear to be more a critique of the AER's stage 2B than its stage 2A. The comments by CitiPower, Powercor and the other DNSPs on the AER's stage 2B is considered in section 6.5.3.

In response to JEN's comments, the AER notes that JEN did not disagree with the possibility of a double-counting of systematic risk between a contract price and the WACC. Rather JEN cautioned about making adjustments due to the complexity of the task. The AER acknowledged the practical difficulties of making such an adjustment in its draft decision and has not identified any such instances of double-counting. Assessing whether such double-counting exists in any of the Victorian DNSPs' outsourcing contracts that pass the presumption threshold has not been a focus of this review. However, in future reviews the AER may focus more on identifying and assessing any instances of double-counting.

6.5.2.4 AER conclusion

Having considered comments from CitiPower, Powercor and JEN in their revised regulatory proposals, for the purposes of this final decision, the AER maintains its view in the draft decision that it is appropriate to assess outsourcing contracts that pass the presumption threshold.

6.5.3 Stage 2B—Assessment where contract fails the presumption threshold

6.5.3.1 AER draft decision

Where a contract does not meet the presumption threshold, the AER considered it cannot presume the contract reflects efficient costs. Therefore, these contracts should be subject to greater scrutiny. In these circumstances the AER considered it appropriate to adopt the contractor's actual (direct) costs—which in most circumstances will be the actual costs of a related party—as the 'starting point' and then examine whether there are legitimate economic reasons to justify a 'margin' above these direct costs.

[58] CitiPower, *Revised regulatory proposal*, pp.148-150; Powercor, *Revised regulatory proposal*, pp.137-140.

Having reviewed the past decisions of the ESCV and consultants reports commissioned in the context of these reviews, the AER considered the following constituted legitimate economic reasons for a margin above a contractor's direct costs:

- an allowance that reflects a reasonable allocation of the contractor's corporate overheads and other indirect costs, though excluding shareholder costs associated with the management of equity (which are compensated through the WACC) and debt and equity raising costs (which are compensated through a separate allowance)
- an allowance that reflects the required return on and return of assets owned and utilised by the contractor, so long as those assets are not already included within the service provider's RAB, and
- an allowance that reflects the asymmetric risk faced by the contractor, so long as the service provider's proposed self insurance allowance has been commensurately reduced to reflect the transfer of risk from the service provider to the contractor.

The AER considered that whether or not a margin is justified, and the magnitude of that margin where justified, requires a 'case-by-case' examination taking into account legitimate economic reasons for the exclusion of a margin.

While the AER also considered that retaining the benefit of historical operating efficiencies for a period of time was another legitimate reason, the AER considered rewarding for these historical efficiencies through the EBSS building block was preferable to providing an additional component of the 'margin' in the opex forecast. This is because the EBSS option ensured that efficiencies realised by related party contractors would be passed through to consumers in the same time period as efficiencies realised by the DNSP itself (being five years after the year in which the efficiency is realised).

The AER stated that comparing efficiencies against those of a hypothetical 'fully in-sourced, standalone' network was not appropriate as it would prevent the economies of scale and scope and other efficiencies (such as 'know-how') realised by related party contractors from being shared with consumers. The AER formed this view on the basis of:

- the reference to 'in the circumstances' of the relevant DNSP in clause 6.5.6(c)(2) and 6.5.7(c)(2)—permitted the AER to take into account the DNSP's ownership circumstances and corporate structure including whether the DNSP was part of a corporate group that owned and operated multiple networks giving it access to significant economies of scale and scope, and
- the AER's understanding of the pricing outcomes that would prevail in a 'workably competitive market'.

In relation to the second point, the AER stated in the draft decision:

> In a workably competitive market, a contractor could not in the long run charge a premium (i.e. a margin) above its full economic costs and earn abnormal profits due to the efficiencies available to the contractor that are not currently available to the service provider or other contractors. This is

> because in a workably competitive market, it is assumed that over time existing contractors will become more efficient or new efficient contractors will enter the market and bid away these abnormal profits. In other words, in a workably competitive market a contractor could not earn abnormal profits in the long run for efficiencies it has realised in the past, it could only continue to earn abnormal profits if it were able to continually improve its efficiency relative to its competitors.
>
> To the extent the difference between a contract price and related party contractor's (full economic) costs reflect past efficiencies, the AER did not consider the contract price should be used to project the future expenditure allowances as this would perpetuate the earning of abnormal profits by the related party which in a workably competitive market would be bided away over time (and therefore not retained indefinitely).[59]

Other relevant considerations included:

- a comparison of the contract price with the service provider's pre-outsourcing costs (particularly where the decision to outsource was made recently), and
- the circumstances surrounding the entering into of the contract or arrangement between the service provider and contractor.

6.5.3.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs generally supported or did not comment on the four reasons that the AER considered were legitimate economic reasons for a margin above the contractor's direct costs.

However, CitiPower, Powercor and JEN also considered that a margin to reflect the full extent of economies of scale and scope realised by the related party contractor was also acceptable. That is, CitiPower, Powercor and JEN argued that contract prices should still be considered acceptable under the NER if they are equal to or less than the standalone, in-house cost of service provision. CitiPower, Powercor and JEN provided both legal and economic reasons why the AER should not have rejected the standalone, in-house cost standard in its draft decision.

JEN also argued that there was a difference between parties having an incentive to agree to non-arm's length terms, while CitiPower and Powercor argued that the AER's approach results in a perverse incentive. CitiPower, Powercor and JEN both identified inconsistencies with the AER's draft decision approach and previous regulatory decisions.

In the following sections, the AER sets out its response to the following issues raised by CitiPower, Powercor and JEN:

- JEN stated there is a difference between parties having an incentive to agree to non-arm's length terms, and the parties acting on that incentive (section 6.5.3.3)
- SP AusNet supported the AER's legitimate economic reasons for the inclusive of a margin, whereas the other DNSPs mostly do no comment on this issue (section 6.5.3.4)

[59] AER, *Draft decision*, p.182.

- CitiPower, Powercor and JEN did not support the AER's rejection of a 'standalone, in-house' cost standard and its treatment of scale, scope and other efficiencies realised by related party contractors (section 6.5.3.5)

- CitiPower, Powercor and JEN argued that the AER's approach creates a 'perverse incentive' for DNSPs to internalise activities even where outsourcing is the more efficient option (section 6.5.3.6), and

- CitiPower, Powercor and JEN identify inconsistencies with the AER's approach and previous regulatory decisions of the AER, ESCV and the Tribunal (section 6.5.3.7).

6.5.3.3 Incentive to agree to non-arm's length terms vs. acting upon the incentive

Victorian DNSP revised regulatory proposals

While JEN acknowledged that the relationship between contracting parties, or the conditions under which the contract was negotiated, may mean that the parties had an incentive to agree to an 'artificially inflated' price, a more detailed consideration of the price and terms specified in the contract is required to determine whether the parties acted upon the incentive. JEN stated that the AER's framework fails to recognise this difference.[60]

JEN referenced a report from NERA in support of the position that a finding that a service provider entering into an outsourcing arrangement with a related party is not itself sufficient to conclude that transfer pricing had actually occurred between the service provider and the related entity.[61]

JEN argued the appropriate test to determine whether the DNSP agreed to an artificially inflated price is to compare the contract price against the in-house cost of providing the service. The conclusion drawn is that if the contract price is less than the in-house cost, then this demonstrates the DNSP did not act on the incentive to agree to an artificially inflated contract price.[62]

AER considerations and conclusion

The AER agrees with JEN that a finding that parties had an incentive to agree to non-arm's length terms is not necessarily sufficient to conclude that they acted on that incentive.

The AER's rejection of the contract margins between the Victorian DNSPs and their related parties in the draft decision was not based solely on the fact that the parties had an incentive to agree to non-arm's length terms. Rather, the existence of such incentives only triggered a closer assessment of these margins against the legitimate economic reasons for the inclusion of a margin. That assessment led the AER to conclude that the Victorian DNSPs' related party margins were not efficient costs or costs that would be incurred by a prudent operator in their circumstances.

[60] JEN, *Revised regulatory proposal*, p.73.
[61] JEN, *Revised regulatory proposal*, p.74.
[62] JEN, *Revised regulatory proposal*, pp.74-75.

Consistent with JEN's proposal and NERA's position, the AER has undertaken a 'more detailed consideration' of the contract price rather than simply removing this margin where an incentive to agree to non-arm's length terms exists.

The difference between JEN's revised proposal position and the AER's position is what that detailed consideration should be. As noted above, JEN argued that if the contract price is less than the in-house cost of providing the service, then this is sufficient to conclude that the contract price is efficient and reflective of arm's length terms. As stated in the draft decision, the AER does not agree than the 'standalone, in-house' cost is the appropriate standard to assess outsourcing contracts against or the standard which is consistent with arm's length terms. The AER addresses this issue in section 6.5.3.5.

6.5.3.4 Legitimate economic reasons for a margin

Reason one: Margin reflects contractor's corporate and other indirect costs

AER draft decision

To the extent that a margin reflects a related party’s reasonable allocation of common costs then that margin is reasonable. However, the AER considered that relying on allowances for corporate overheads based on an unsubstantiated percentage that is added to direct costs (for example, direct costs plus 6 per cent for corporate overheads) is not sufficient to establish an appropriate forecast. Rather, as with most other operating costs, an allowance for corporate overheads should be based on historical actual costs, adjusted as appropriate to reflect expected changes in real labour price movements and other such factors.

In addition, the AER stated it must ensure that only a proper allocation of the related party’s corporate costs, and corporate costs that should be allocated to the service provider in the first place, are included in an allowance.

The AER noted and agreed with the ESCV's position from the 2008–12 GAAR, that:

- costs incurred by a parent entity in undertaking corporate functions that would be required of a distribution business meeting the benchmark assumption should be allocated to the service provider’s opex. These functions include corporate governance, treasury, investor relations, HR management and statutory reporting
- costs associated with the management of the equity holders’ ownership interests (including the parent entity’s ownership interest) should not be allocated to the service provider’s opex. That is, costs which are directly associated with the management of equity and not operational costs required to in the provision of regulated services are already compensated through the WACC.
- costs associated with the parent entity’s capital raising costs should not be allocated to the service provider’s opex as a separate benchmark allowance is provided for these costs.

The AER stated that management fees paid to parent companies included within the related party’s actual costs should also be considered closely to ensure that these fees contribute to the provision of distribution services, and the service provider has substantiated these fees are efficient costs that would be incurred by a prudent operator.

Victorian DNSP revised regulatory proposals

JEN did not comment specifically on this issue, however in its proposed alternative framework it proposed a similar component, which JEN described as:

> an appropriate portion of the contractor's common costs.[63]

SP AusNet supported the AER's draft decision position, stating:

> SP AusNet accepts the position that corporate overheads should be based on historical actual costs, adjusted to reflect expected changes in real labour price movements and other such factors. Costs incurred by a parent entity in undertaking corporate functions that would be required of a DNSP meeting the benchmark assumption, should be allocated to the service provider's operating expenditure.[64]

However, SP AusNet considered the AER seemed unwilling to accept parent entity costs.

CitiPower, Powercor and United Energy did not comment on this issue.

AER considerations and conclusion

While the AER has maintained its specification of this margin component from the draft decision, it considers there to be little to no significant difference in the meaning of the phrasing proposed by JEN and the AER's phrasing.

In response to SP AusNet, the AER does accept parent entity costs but considers they need to be assessed closely to ensure they are not shareholder costs and to ensure that the additional corporate overheads from the parent does not lead to an overall excess amount of corporate costs which are inefficient or imprudent. The AER's analysis of corporate cost adjustments it made to SP AusNet's initial proposal in the draft decision are discussed in section 6.7.

The AER maintains its position on this margin component from the draft decision, noting that the DNSPs' revised regulatory proposals were generally either supportive of or did not comment on the AER's position on this issue.

Reason two: Margin reflects the required return on and of assets owned and utilised by contractor in the provision of the relevant service

AER draft decision

The AER noted that a common argument put to regulators is that all contracts with third parties, including efficiently priced contracts with related parties, will necessarily include a ‘profit margin’ above the contractor’s direct and common costs. The AER recognises that this sentiment was expressed by the Tribunal in its judgement on the AMI appeal. However, the Tribunal stated that its judgement in that matter was not to be seen as a precedent for the treatment of related party margins, generally.

[63] JEN, *Revised regulatory proposal*, p.86.

[64] SP AusNet, *Revised regulatory proposal—Revised related party arrangements appendix*, July 2010, pp.11-12.

The AER stated that the regulatory regime does not explicitly provide service providers with a ‘profit allowance’. But in its place, it provides a ‘return on capital’ building block allowance which is calculated as the cost of capital multiplied by the RAB. This provides a reasonable return to both equity holders and debt holders for their investment in the service provider. In addition, a ‘return of capital’ building block allowance is provided which compensates, over time, for the original cost of the assets used by the service provider (which is equivalent to the capital investment by equity and debt holders).

The AER considered a central issue in relation to whether a ‘profit margin’ in an outsourced contract is justified is whether or not the assets used by the contractor to deliver the service—regardless of whether it is a construction or maintenance service—are already included in the service provider’s RAB. For example, the assets used by a contractor to deliver a construction or maintenance service may include depots, vehicles, equipment and other such assets. Where all of these assets are already in the service provider’s RAB, and at the same time the service provider’s capex or opex forecast is built on a contract that includes a profit margin (where that profit margin is to compensate for the return on / return of capital associated with assets used by the contractor)—then this is clearly a ‘double-counting’ of the same assets.

The AER noted that a non-related party contractor would be expected to own a certain amount of assets used to deliver construction or maintenance services. It would be highly unusual and would not be expected if these assets were already included in the service provider’s RAB. Accordingly, the AER stated it can be expected that an efficiently priced contract with a non-related party would include a profit margin above the direct and common costs of the contractor to compensate for the return on / return of capital associated with these assets. In contrast, the AER stated its understanding was that it is common for at least some (if not all) assets utilised by related party contractors to already be included in the service provider’s RAB.

The AER concluded that a profit margin in a contract with a related party is only justified to the extent it utilises assets not already in the service provider's RAB.

Victorian DNSPs revised regulatory proposals

JEN did not comment specifically on this issue, however in its proposed alternative framework it proposed a similar component, which JEN described as:

> the return on and return of assets required by the contractor for those assets it owns and are used in the provision of services to the DNSP[65]

SP AusNet supported the AER's draft decision position, stating:

> SP AusNet accepts the Draft Determination's position that the regulatory regime provides a 'return on capital' building block allowance in place of a 'profit margin', thus a profit margin in a contract with a related party can only be justified to the extent the related party utilises assets not already in the service provider's Regulatory Asset Base (RAB).[66]

[65] JEN, *Revised regulatory proposal*, p.86.

[66] SP AusNet, *Revised regulatory proposal—Revised related party arrangements appendix*, July 2010, p.12.

CitiPower, Powercor and United Energy did not comment on this issue.

AER considerations and conclusion

The AER agrees with JEN's proposed margin component so long as the assets in question are not already included with the service provider's RAB, for the reasons outlined in the draft decision (summarised above).

The AER maintains its draft decision position on this margin component, noting that the Victorian DNSPs' revised proposals were either supportive of or did not comment on the AER's position on this issue.

Reason three: Margin reflects the allowance required to self-insure against the asymmetric risks faced by the contractor

AER draft decision

The AER considered a margin to compensate for the asymmetric risks of the contractor was also legitimate, but only if the service provider’s proposed self insurance allowance has been commensurately adjusted to only include asymmetric risks faced by the service provider (and not those risks that the service provider has transferred to the contractor through its contracting arrangements).

Victorian DNSP revised regulatory proposals

SP AusNet supported the AER's draft decision position, stating:

> SP AusNet accepts the view that a margin to compensate for asymmetric risks of the related party is legitimate, only if the service provider's proposed self insurance allowance has been commensurately adjusted to only include asymmetric risks faced by the service provider (and not those risks that have transferred to the related party through the arrangements).[67]

CitiPower, Powercor, JEN and United Energy did not comment on this issue.

AER considerations and conclusion

The AER maintains its draft decision position on this margin component, noting that the DNSPs' revised proposals were either supportive of or did not comment on the AER's position on this issue.

Reason four: Margin reflects the historical or future efficiencies of the contractor (such as economies of scale or scope)

This matter is discussed in section 6.5.3.5.

Reason five: Margin reflects the 'know-how' of the contractor

AER draft decision

The AER notes that another argument sometimes put forward by service providers as to why a margin above a related party contractor’s actual costs should be allowed is due to the ‘know-how’ available to a contractor that would not be available to the service provider. Alternatively, this is argued from the perspective that the contractor holds ‘intangible’ assets for which it should be allowed to recover both a return on and return of capital associated with those intangible assets.

[67] SP AusNet, *Revised regulatory proposal—Revised related party arrangements appendix*, July 2010, p.12.

For example, there are few capital assets associated with the provision of most alternative control services. However, there is a degree of ‘human capital’ (or intangible assets) employed in the provision of these services. These human capital costs are operating costs which are expensed and do not earn a return under the building block approach. The AER noted that some Victorian DNSPs had expressed a view that without a profit margin or a return on these intangible assets, there would be no incentive for their related parties, or the DNSPs themselves, to provide the alternative control services.[68]

The AER noted the views of NERA, commissioned by Envestra in the context of the last Victorian GAAR, which the ESCV summarised as:

> Dr Hird provides evidence of the value of intangible assets of a business and draws a conclusion that ‘the only reason that a contractor can charge a margin on its actual costs is if the contractor has previously invested in the costly development of those intangible assets’. Dr Hird considers that to not consider a margin over and above actual costs of the contractor as an element of costs implies that:
>
> - the contractor does not hold valuable intangible business processes and knowledge or
> - that the distributor could have costlessly acquired those assets or
> - that the distributor should have acquired these assets in the past and should be treated as if it holds the assets[69]

The AER also noted and generally agreed with the ESCV's rejection of this argument in the GAAR.

Specifically, the AER stated, as NERA points out, ‘know-how’ or intangible assets are not acquired by a business without cost. The AER considered that these acquisition costs might involve specific training costs, or more broadly the costs of experience.

The AER stated that one of the considerations it takes into account in assessing DNSPs' forecasts is the ‘revealed cost’ (particularly opex) that is projected from historical actual expenditure. Importantly, the AER noted that the ESCV's opex and capex allowances for the Victorian DNSPs in the current regulatory control period were based on the historical opex and capex of the DNSPs and their related parties. Accordingly, to the extent that a service provider currently possesses ‘know-how’, this know-how has most likely already been funded by customers. This is because the DNSPs’ current expenditure allowances were for the most part based on their historical actual costs in the past before it acquired this know-how and so when it was relatively less efficient than it currently is.

To the extent the service provider’s or related party contractor’s know-how has or will lead to future efficiencies (for example, through lower costs) then the AER considered it should be treated the same way as other operating and capital efficiencies. That is, the service provider and its related party should retain the benefit of this efficiency for

[68] AER, File note—Meeting with CitiPower and Powercor, 18 February 2010.

[69] ESCV, *Gas access arrangement review 208-2012—Final decision—Public version*, 7 March 2008, pp. 56–57.

a time, but after that time the benefit should be passed on to consumers. In contrast, for customers to pay a margin above a related party's actual costs because of the 'know-how' or intangible assets in the possession of the related party would be to ask customers to fund something that they have already funded in the past. Accordingly, such expenditure could not be considered efficient or the costs of a prudent operator in the circumstances of the DNSP.

Victorian DNSPs revised regulatory proposals

SP AusNet supported the AER's draft decision position, stating:

> SP AusNet also accepts the Draft Determination's approach to operating and capital expenditure in relation to the treatment of efficiencies. To the extent that a service provider's or related party contractor's know-how has or will lead to future efficiencies, SP AusNet accepts that it should be treated in the same way as most other efficiencies with the service provider and related party retaining the benefit of this efficiency for a time before the benefit passes on to customers.[70]

CitiPower, Powercor, JEN and United Energy did not comment on this issue.

AER considerations and conclusion

The AER maintains its draft decision position on this margin component, noting that the DNSPs' revised proposals were either supportive of or did not comment on the AER's position on this issue.

6.5.3.5 Rejection of a hypothetical 'standalone, in-house' cost standard and treatment of efficiencies realised by related party contractors

AER draft decision

In the draft decision, the AER considered the related issues of:

- whether expenditure forecasts should be assessed against those of a hypothetical 'fully in-sourced, standalone' network, and
- whether a margin paid to a related party contractor above its direct and indirect costs which reflects the historical or future efficiencies should be included within a DNSP's expenditure forecasts

The core of this issue is whether the benefit of economies of scale, scope and other efficiencies realised by related party contractors through operating multiple networks should be retained indefinitely within a DNSP's corporate group, or whether these benefits should be shared with consumers.

The AER's view was that efficiencies realised by related party contractors should be treated the same as other operating and capital efficiencies under the regulatory regime. That is, DNSPs and related party contractors should retain the benefit of these efficiencies for a period of time but eventually these benefits should be passed on to consumers. Specifically:

[70] SP AusNet, *Revised regulatory proposal—Revised related party arrangements appendix,* July 2010, p.12.

- operating efficiencies should be retained for five years in addition to the year they are realised, and
- capital efficiencies should be retained until the end of the regulatory control period in which they are realised.

The AER sought to achieve this retention period in relation to operating efficiencies realised by related party contractors by:

- adopting as the basis for the opex forecast the related party contractor's actual historical (direct and indirect costs)—noting that these historical costs will include historical and realised efficiencies but ignore expected but unrealised future efficiencies)[71]
- using the related party contractor's actual costs (and not the contract price) when measuring efficiencies at the end of the regulatory control period for the purposes of the EBSS, and
- indicating its intention to adopt the related party contractor's (now more recent) actual historical costs as the basis for the opex forecast in the following regulatory control period.

For capex, the AER also considered that a contract margin that reflects historical realised efficiencies should not be used in assessing future expenditure allowances (that is, this margin should be removed first). Similarly, any expected but currently unrealised efficiencies should be ignored when assessing future capex allowances.

The AER reasoned this approach based on its view that 'in the circumstances' of the relevant DNSP, as referred to in clauses 6.5.6(c)(2) and 6.5.7(c)(2), refers to the actual circumstances of the relevant DNSP and the expected pricing outcomes in a workably competitive market.

Meaning of 'in the circumstances'
In the draft decision, the AER noted:

- while each of the Victorian DNSPs are separate legal entities, they are also all part of a broader group of companies or corporate group[72]
- each of the Victorian DNSPs, being part of broader corporate groups, have access to significant economies of scale, scope and other efficiencies that would not be available to a 'standalone' network, and [73]

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[71] At a particular point in time, a contractor's actual costs will necessarily incorporate the effect of any efficiency gains it has realised in the past but exclude any future efficiency gains it is expected to realise in the future but is yet to achieve (and which will therefore lead to its actual costs in the future being lower).

[72] For example, CitiPower and Powercor are part of the CKI group (which also includes ETSA Utilities), SP AusNet and JEN are part of both a broader group of 'SP AusNet' networks and 'JEN' networks, while ultimately, also all being part of the Singapore Power group. And United Energy is part of a group of DUET-majority owned networks, which includes MultiNet.

[73] Generally speaking, specialist related parties within these groups provide a particular type of service (for example, management) to all entities within the group. Sometimes these services are on-

- accordingly, whether or not they should be treated as though they were standalone networks for the purposes of assessing expenditure forecasts under the NER is an important question.

The AER considered if the reference to 'in the circumstances' in clause 6.5.6(c)(2) and 6.5.7(c)(2) refers to the costs of a hypothetical ‘standalone’ network, this would justify a profit margin being added by related parties when charging the service provider that reflects the full extent of the economies of scale and scope available to the related party through operating multiple networks. Such a margin could therefore be justified indefinitely and these economies of scale, scope and other efficiencies available to the group within which the DNSP belongs would be retained indefinitely within that group (that is, by the DNSP's shareholders) and not shared with consumers.

The AER did not accept this position and considered that the ‘circumstances’ of the DNSP includes its ownership structure, and in particular whether or not it is part of a large group of networks giving it access to economies of scale, scope and other efficiencies that would not be available to a hypothetical ‘standalone’ network.

Were a service provider to actually be a ‘standalone’ network and not connected to a corporate group that owned and operated multiple networks, the AER considered it should not be penalised through setting its expenditure allowances below its costs (that is, at a level that would be incurred by a multi-network business). However, should that service provider (or the corporate group the service provider is in) acquire other networks, the AER considered those merger synergies should be retained for a period of time by the service provider but eventually passed through to consumers.

Accordingly, the AER concluded that a ‘standalone’ cost standard would only appear appropriate if that reflects the actual circumstances the service provider is found in. Where a service provider is part of a larger corporate group that owns and operates multiple networks, then these are the circumstances that service provider is found in. The AER considers this is relevant in assessing the costs that would be incurred by a prudent operator in the circumstances of that DNSP.

The AER concluded that economies of scale or scope or other efficiencies (for example, ‘know-how’) are not a legitimate reason for a related party contractor to charge the service provider above its direct and indirect costs, as this approach would prevent consumers from sharing in these benefits.

The AER noted this approach is consistent with how the ACCC has treated merger synergies, such as in the last GasNet access arrangement review, however this approach is different to the ESCV’s approach in the 2008–12 GAAR, where the ESCV adopted an 'in-house' cost standard test.

The AER noted that where the terminology ‘standalone’ network is used in relation to the appropriate expenditure assessment test, it is often (though not always) meant to imply a *fully in-sourced* standalone network.

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charged to the DNSP ‘at cost’ (particularly within the SP AusNet group), however these services are mostly on-charged to the DNSP on a ‘cost plus profit margin’ basis (for example, in relation to CitiPower's and Powercor's main related party contractors).

The AER considered that even a standalone network is able to outsource to specialist contractors rather then providing each service in-house. Indeed, it would seem unlikely that the most efficient model of service provision for a standalone network would be to provide each service in-house, and not to procure any services from an external party (for example, not to seek legal advice from specialist law firms and rather to always rely on its own internal legal staff).

Accordingly, the AER did not consider the concept of a ‘fully in-sourced’ network is appropriate in assessing margins which are consistent with forecast capital expenditure or forecast operating expenditure that reasonably reflects, respectively, the capital expenditure criteria or the operating expenditure criteria.

Efficient costs and pricing outcomes from a workably competitive market

The AER considered that were the Victorian DNSPs to procure the contracts with their related parties through an open tender process in a competitive market, there would be no need to closely examine the margins in these contracts, as the AER could reasonably rely on ‘the market’ pricing these services efficiently. However, the AER’s understanding of the workings of a ‘workably’ competitive market provided an insight into the appropriate treatment of these relative efficiencies.[74]

The AER considered that, in a workably competitive market, a contractor could not in the long run charge a premium (that is, a margin) above its full economic costs and earn abnormal profits due to the efficiencies available to the contractor that are not currently available to the service provider or other contractors. This is because in a workably competitive market, it is anticipated that over time existing contractors will become more efficient or new efficient contractors will enter the market and bid away these abnormal profits. In other words, in a workably competitive market a contractor arguably could not earn abnormal profits in the long run for efficiencies it has realised in the past, it could only continue to earn abnormal profits if it were able to continually improve its efficiency relative to its competitors.

To the extent the difference between a contract price and related party contractor’s (full economic) costs reflect past efficiencies, the AER did not consider the contract price should be used as the basis for future expenditure allowances as this would perpetuate the earning of abnormal profits by the related party which in a workably competitive market would be competed away over time (and therefore not retained indefinitely). Instead, the AER considered that expenditure forecasts should not include an upwards adjustment above the related party’s actual costs to reflect these historically realised efficiencies. Importantly, however, in adopting the related party’s costs no downwards adjustments should be made to reflect any future expected but currently unrealised efficiencies of the related party. Importantly, the AER also proposed that at the end of the regulatory control period, the related party contractor’s actual costs (rather the service provider’s costs, that is, the contract price) should be used to measure efficiencies under the EBSS. The result of this is to reward for historical efficiencies through EBSS payments. Consequently, historical efficiencies in the contract margins should not be accepted into the expenditure forecasts. Such an approach provides the service provider with a revenue stream to pay its related party

[74] One of the objectives of the regulatory regime is to reflect the outcomes of a competitive market. This is generally regarded as the outcomes of a ‘workably’ competitive market rather than a ‘perfectly’ competitive market.

an amount greater than its full economic costs, but only in the short run not the long run, consistent with the workings of a workably competitive market.

The AER noted the consistency between its approach and the ACCC's treatment of merger synergies in the last GasNet decision. In that reset, the ACCC's approach was:

- to ignore both one-off merger (transaction or restructuring) costs and expected (though unrealised) cost reductions resulting from merger synergies for the purposes of determining the forecast opex allowance

- to allow the service provider to retain those merger related cost reductions for a period of six years through the above approach to determining the forecast opex allowance and the calculation of the EBSS allowance at the following reset, and

- to factor those merger synergies into the forecast opex allowance for the following regulatory control period after those cost reductions have been realised.

Under this approach, the merged group of which the service provider is part will retain the merger synergies for six years (regardless of when they are realised) and after this time the benefit of these efficiencies will be passed through to consumers. Importantly, under this approach, somewhat artificial corporate distinctions where a division of a service provider (for example. its field services team) is turned into a separate but wholly owned company, does not affect the regulatory treatment of merger synergies. Consequently, such somewhat artificial distinctions do not affect the incentive power for the service provider to seek out efficiencies, or the timing of efficiency sharing between the service provider (including its related parties) and consumers.

Treatment of incentive payments in contracts between the DNSP and contractor

In the draft decision, the AER considered that where the opex forecast is being based on a DNSP's historical expenditure that includes incentive payments paid to a related party contractor arising from the incentive arrangements in the contract between the parties (for example, for meeting or exceeding set KPIs) that these incentive payments should be:

- excluded from the forecast opex allowance, and

- excluded from the actual opex for the purposes of measuring efficiencies under the EBSS.[75]

The AER stated this approach ensures that the efficiencies achieved by the related party are rewarded as if the DNSP achieved those efficiencies itself. The division of that reward between the DNSP and related party was then a matter for those parties to settle on without interference from the AER.[76]

The AER noted this approach is consistent with that taken by the ESCV in the 2008–12 GAAR, in which context the ESCV stated:

[75] AER, *Draft decision*, p.188.
[76] AER, *Draft decision*, p.188.

> The Commission did not consider that it was appropriate to include these payments in the forward looking cost benchmarks. The reason for this is that the Commission is required to consider the forward looking costs of providing the services, whereas an historical sharing of efficiency savings does not actually reflect a future cost of providing the service. Rather, it is a payment between the owner and the operator / manager to reflect superior performance in the past. It must be recognised that this does not mean that the distributor does not receive any allowance for the efficiency saving; they do, but they receive it through the efficiency carryover mechanism. It should also be recognised that this treatment in no way limits the ability of the distributor to share future efficiency savings with the operator / manager.[77]

Victorian DNSP revised regulatory proposals

Meaning of 'in the circumstances' and AEMC intent

CitiPower and Powercor noted that the NEL requires that the NER be given a purposive rather than a literal interpretation. CitiPower and Powercor stated that they have reviewed the AEMC's rule determination released in the context of the chapter 6A review.[78] JEN stated that is has reviewed both the rule determination and the legal advice the AEMC received on the drafting of the expenditure criteria.[79]

JEN considered the AEMC had two intentions behind the inclusion of the phrase 'in the circumstances of the relevant' DNSP, whereas CitiPower and Powercor considered the AEMC had one intention.[80]

CitiPower, Powercor and JEN concluded that the AEMC's intent was not to allow regard to be had to the group structure of a DNSP in assessing its expenditure forecasts. Rather, CitiPower and Powercor consider that the AEMC's intent was to require a consideration of the network operating conditions of the DNSP. Similarly, JEN stated that the AEMC's intent was:

> …to focus on the operational circumstances of the DNSP (ie, network size and location of the network) rather than reflecting the ownership interests of the DNSP.[81]

The three DNSPs drew this intent from the AEMC's statement that the criteria were 'more … operationally focused' than the test previously under consideration.[82]

CitiPower and Powercor also argued that this is consistent with the prudency criterion as a 'counter-balance' to the efficiency criterion as contemplated by the AER's consultant (Wilson Cook) in the context of the NSW electricity distribution determination.[83]

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[77] ESCV, *Gas access arrangement review 208-2012—Final decision—Public version*, 7 March 2008, p. 57.

[78] CitiPower, *Revised regulatory proposal*, pp.507-508; Powercor, *Revised regulatory proposal*, pp.513-514.

[7979] JEN, *Revised regulatory proposal*, pp.75-76.

[80] CitiPower, *Revised regulatory proposal*, pp.507-508; Powercor, *Revised regulatory proposal*, pp.513-514; JEN, *Revised regulatory proposal*, pp.75-76.

[81] JEN, *Revised regulatory proposal*, p.76.

[82] CitiPower, *Revised regulatory proposal*, p.508; Powercor, *Revised regulatory proposal*, p.514; JEN, *Revised regulatory proposal*, p.76.

[83] CitiPower, *Revised regulatory proposal*, pp.508-512; Powercor, *Revised regulatory proposal*, pp.514-518.

JEN argued that the AEMC's intent was not to infer inefficiency or imprudence from a DNSP's circumstances, and particularly its corporate structure. Rather, it argued that the AEMC's intent was to require, among other things, that consideration be given to whether the DNSP has prudently sought to protect its own commercial interests in negotiations with the related party contractor, rather than favouring the interests of the contractor of the wider corporate group. JEN stated that this could be assessment by:

- Examining whether the price paid under the contract is less than, or equal to, the costs that would be incurred by the DNSP operating on a standalone basis,[84] and / or

- Comparing the terms and conditions specified in the agreement with those contained in contracts entered into by parties operating on an arm's length basis.[85]

Assumption that DNSP can access services from related party contractor 'at cost'
CitiPower and Powercor argued that even if the AER is correct in concluding that 'the circumstances of the relevant distribution network service provider' include its ownership structure:

- the prudency criterion refers to the circumstances of the relevant DNSP and not to the circumstances of the group to which the DNSP belongs

- the relevant inquiry is one of the costs that the DNSP itself (as distinct from the group to which the DNSP belongs), acting prudently, would require to achieve the opex and / or capex objectives

- the AER cannot exclude any scale and scope efficiencies achievable by the group to which a DNSP belongs from the benchmark costs against which a DNSP's expenditure forecasts are assessed in applying the prudency criterion, without first satisfying itself that those efficiencies could be accessed without cost (that is, without a margin) by the DNSP, acting prudently.[86]

CitiPower and Powercor attempted to establish a reason why a DNSP could not access services from its related party contractors 'at cost', that is, without having to pay a margin above the related party contractors incurred costs commensurate with the economies of scale and scope available to the related party. CitiPower and Powercor stated:

> It cannot be assumed that scale and scope efficiencies achievable by the group are necessarily available to a DNSP, acting prudently. Despite the fact that the entities form part of a commonly owned group, they remain separate legal persons for all legal, regulatory and other purposes. By operation of the *Corporations Act 2001 (Cth)* and various other laws, each company within the group to which the DNSP belongs owes independent fiduciary, contractual and other obligations to its financiers, creditors, employees and other stakeholders. These obligations of a group entity to third parties cannot be disregarded in dealings with another group entity simply because the two

84 As JEN argues that a prudent operator that is part of a broader corporate group would be expected to pay no more than the cost of in-house service provision for services provided under the contract.
85 JEN, *Revised regulatory proposal*, p.76.
86 CitiPower, *Revised regulatory proposal*, pp.508-509; Powercor, *Revised regulatory proposal*, pp.514-515.

> entities fall within the same ultimate ownership structure and it is not correct that superior cost arrangements are necessarily or automatically available simply because that common ownership structure exists. Accordingly, a member of the group may not provide to the DNSP the benefits of the scale and scope efficiencies available to it at no cost because of its legal obligations to third parties.
>
> …
>
> There may be scope to exclude these efficiencies under the efficiency criterion by reference to the costs that would prevail in a workably competitive market … but it is impermissible for the AER to do so by application of the prudency criterion.[87]

Efficient costs and pricing outcomes from a workably competitive market

CitiPower and Powercor accepted that:

- pricing under outsourcing arrangements is efficient if that pricing is set in a workably competitive market through an open tender process or mimics the pricing outcomes that would prevail in a workably competitive market through an open, competitive tender process, and
- in a workably competitive market a contractor could not charge a premium above its full economic costs in the long run

CitiPower and Powercor stated they accept that the efficiency criterion, properly construed and applied, necessitates an inquiry into the pricing outcomes in a workably competitive market.[88]

However, CitiPower and Powercor noted that they disagreed that it follows from the application of these propositions, that scale, scope or other efficiencies realised by a contractor in the current or previous regulatory periods would never warrant the payment of a margin to that contractor in the forthcoming regulatory control period.

Similarly, JEN stated that while in theory any 'abnormal profits' earned by a contractor operating in a workably competitive market can be expected to be competed away over the longer term, it is possible in the short to medium term that contractors may be able to generate 'abnormal profits'. JEN stated the AER appears to have given no consideration to the potential for this to warrant the payment of a margin in the short to medium term.[89]

CitiPower and Powercor also considered the AER's assumption that the long run is any period in excess of a five year regulatory period is erroneous, because it is:

- contrary to a prior Tribunal decision, and
- contrary to observed commercial practices

Similarly, JEN stated that benchmark studies of margins earned by contractors supplying comparable services to those procured by the Victorian DNSPs provide

[87] CitiPower, *Revised regulatory proposal*, p.509; Powercor, *Revised regulatory proposal*, p.515
[88] CitiPower, *Revised regulatory proposal*, p.509; Powercor, *Revised regulatory proposal*, p.515.
[89] JEN, *Revised regulatory proposal*, pp.80-81.

clear evidence that the majority of contractors consistently earn margins in excess of the amounts viewed by the AER as constituting an acceptable basis for a margin. JEN referenced the same benchmark studies as CitiPower and Powercor in support of this contention.[90]

Other issues

CitiPower and Powercor argued that in striking a reasonable balance between the efficiency and prudency criteria, the AER has no discretion to reduce a DNSP's expenditure forecasts below the efficient costs of achieving the opex and capex objectives, on the basis of its assessment of that expenditure forecast against the prudency criterion.[91]

CitiPower and Powercor also argued that the AER should not take into account the efficiencies derived by the contractor from the provision of unregulated services or the provision of services to third parties when assessing a DNSP's forecast opex and capex under an outsourcing arrangement that fails the presumption threshold. That is, just as the costs associated with the provision of unregulated services should not be taken into account when deriving forecasts for the standard control service neither should be benefits derived from the provision of these services.[92]

Similarly, JEN stated that clauses 6.5.6(b)(2) and 6.5.7(b)(2) of the NER state that forecast opex and capex must be for expenditure that is 'properly allocated to standard control services'. This limitation has been included to prevent any costs incurred by the DNSP in the provision of non-standard control distribution services being passed onto consumers. In JEN's view, it could be reasonably inferred from this provision that if the costs associated with the provision of services other than standard control services are to be disregarded when developing forecast expenditure, then so too should any efficiencies derived by the contractor from the provision of unregulated services. JEN argued it follows that even if the AER is to have regard to the DNSP's ownership structure when assessing forecast opex and capex, the AER should not have regard to the efficiencies derived by the contractor from:

- the provision of services to third parties
- the provision of services to other entities in which the contractor's parent entity has an interest, including other regulated entities, and
- the provision of alternative control and negotiated services to the DNSP.

Issues and AER considerations

Meaning of 'in the circumstances' and AEMC intent

The AER agrees with CitiPower and Powercor that a purposive rather than literal interpretation of the NER is required by the NEL. The AER considers that, where the same provisions appear in chapter 6 and chapter 6A, the AEMC's chapter 6A rule determination may appropriately inform the interpretation of the equivalent provisions in chapter 6.

[90] JEN, *Revised regulatory proposal*, p.80.
[91] CitiPower, *Revised regulatory proposal*, p.139; Powercor, *Revised regulatory proposal*, pp.129-130.
[92] CitiPower, *Revised regulatory proposal*, p.139; Powercor, *Revised regulatory proposal*, p.130.

However, the AER does not agree with CitiPower, Powercor and JEN in relation to the AEMC's reference to 'operational circumstances'. As Frontier Economics (commissioned by United Energy) points out:

> The AEMC's main focus in its Final Determination was to justify its refusal to adopt a 'best estimates' approach to setting operating expenditure while retaining some objectivity in the assessment of DNSPs' proposed expenditure forecasts, rather than precisely defining the benchmark against which proposed costs should be assessed.[93]

The AER has reviewed the AEMC's final rule determination and agrees that the focus of this part of the AEMC's rule determination was as described by Frontier Economics.

Accordingly, the AER considers that the DNSPs' 'circumstances' should be given its ordinary meaning, which includes operating circumstances (such as network size and location) and ownership circumstances. Nothing in the AEMC's rule determination suggests that operating and ownership circumstances could not both be considered under the prudency criterion.

The AER also considers that the efficiency criterion and prudency criterion are complementary and not competing. This is further considered in chapter 7 (opex) and chapter 8 (capex).

Assumption that DNSP can access services from related party contractor 'at cost'
CitiPower and Powercor appeared to suggest that its related party contractors have a legal obligation to make a profit in their transactions with CitiPower and Powercor, and accordingly CitiPower and Powercor are not able to access services from their related party contractors 'at cost'.

The AER understands is that there is no general obligation under Australian corporations law that would strictly require CitiPower’s and Powercor's related party contractors to include a profit component in their charges to CitiPower and Powercor. When contracting with a third party, a company’s directors may conclude that failing to include a (reasonable) profit component in charges for services provided would breach their obligations to act in that company’s best interests. However, the directors of a related party contractor will not necessarily have to have to form such a view when contracting with CitiPower or Powercor, which is part of the same wholly owned corporate group.

Further, somewhat at odds with CitiPower's and Powercor's submission, the AER notes that a number of JEN's and SP AusNet's related party transactions are conducted at cost without a profit component.

While in the draft decision the AER considered that the DNSP and related party contractor should benefit from the scale, scope and other efficiencies realised by the related party, it considered the appropriate mechanism for this to occur was via EBSS payments rather than via a margin included within the expenditure forecasts.

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[93] UED, *Revised regulatory proposal—Appendix C.17 (Frontier Economics, Meaning and application of National Electricity Rule 6.5.6(c)—A report prepared for Johnson Winter & Slattery, July 2010, p.5.)*

Efficient costs and pricing outcomes from a workably competitive market

In the draft decision, the AER did not, as suggested by CitiPower, Powercor and JEN, consider that efficiencies realised in the current period would not warrant a payment in the short to medium term (that is, the forthcoming regulatory control period). The AER's approach was to measure and reward for the related parties operating efficiencies from the current period through the EBSS payments rather than through the opex forecast in the forthcoming period. Accordingly, the AER's approach leads to a lower operating forecast but higher EBSS payments which will reward their related party contractors in the forthcoming period for efficiencies they realise in the current regulatory control period.

CitiPower, Powercor and JEN have disagreed with the AER's position on the appropriate timing of passing through efficiencies in a workably competitive market, referring to the Australian Competition Tribunal (the Tribunal) in *Application by Optus Mobile Pty Limited and Optus Networks Pty Limited.* In this matter, the Tribunal established that in a workably competitive market a service provider may gain a competitive advantage by having access to economies of scale and scope and by reason of its ownership and operation of other networks in addition to the regulated network such that the standalone, in-house costs of service provision is the cost benchmark that best reflects the pricing outcomes that would prevail in a workably competitive market.[94]

The AER notes firstly that the legislation considered in that case was different. For example, the ACCC was not required to consider whether the costs that would be incurred by a prudent operator in the position of the regulated entity. Secondly, under section 152AB(6) of the *Trade Practices Act 1976* (Cth), regard must be had by the ACCC (and by the Tribunal on review) to, among other things:

> …the legitimate commercial interests of the supplier of the services, including the ability of the supplier to exploit economies of scale and scope.

The NEL and the NER do not refer to the legitimate commercial interests of the Victorian DNSPs. Further, in the matter *Re Vodafone Network Pty Ltd & Vodafone Australia Limited*[95]—which was subsequent to the Optus matter—the ACCC proposed a different view to the Tribunal on the meaning of a service provider's legitimate commercial interests to exploit economies of scale and scope. The Tribunal summarised the ACCC's position as follows:

> The Commission argued that to base the prices of [a mobile network operator for the mobile terminating access service] with a market share of, say, 1%, on its actual costs, would constitute a subsidy from access seekers for its inefficient costs. On the other hand, the Commission's position was that an operator's actual costs provide an upper bound as a basis for prices, so that an operator with more than 25% market share should not be able to adjust its costs upwards to take account of the lesser economies of scale and scope it would enjoy were it smaller, that is, were it the size of the benchmark operator. The Commission saw no inconsistency in arguing that

[94] CitiPower, *Revised regulatory proposal*, p.139; Powercor, *Revised regulatory proposal*, p.129; JEN, *Revised regulatory proposal*, pp.78-79.

[95] *[2007] ACompT 1 (11 January 2007)*

> the larger operator's legitimate business interests, relevant under s 152AH(1)(b), dictate that it receive no more than its actual costs.[96]

While the Tribunal made some commentary on the ACCC's (and Vodafone's) positions, it did not form a definitive judgement, stating:

> Having regard to the conclusions we have reached in relation to other aspects of Vodafone's cost models and in relation to the Pass Through Safeguard, it is not necessary for us to reach a concluded view on what it the benchmark of an efficient operator by reference to which an MNO's costs are to be assessed for their efficiency.[97]

In any event, the economic issues are also quite different. There are different market structures and dynamics between the telecommunications and electricity markets. The Optus case concerned an instance where market participants were competing in many aspects of their activities. While there was no competition in relation to the termination access services for any particular carriage service provider, the costs imposed by setting that price were carried by other service providers (or their customers). The inter-relationship between market participants was much more complex and, in any event, of a different nature to the position in relation to the national electricity market, and in particular, the provision of standard control services by DNSPs.

The Optus case involved the ACCC and Tribunal operating under a framework where part of its role was to promote competition in certain markets. With the relevant market, in particular, being a contestable market where Optus competes with other operators—some of whom are 'standalone' operators in the sense they do not operate in other markets, whereas others (for example, Telstra) operate in both in the mobile market and the market for the provision of fixed line infrastructure services. Accordingly, it might be argued that a 'standalone' benchmark in that context promotes competition in the mobile market. The market for standard control services is not a competitive market. Accordingly, it is difficult to see how competition in a relevant market is promoted by adopting a 'standalone, in-house' benchmark in the context before the AER.

In summary, the AER does not agree with CitiPower, Powercor and JEN that the Tribunal's previous comments on the regulatory treatment of economies of scale and scope are persuasive.

The AER responds to the margin benchmarking reports referred to by CitiPower, Powercor and JEN in section 6.5.5.

The AER now turns to furthering its reasons for the timing of the efficiency sharing with consumers which it has adopted and considers consistent with that in a workably competitive market.

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[96] *Re Vodafone Network Pty Ltd & Vodafone Australia Limited [2007] ACompT 1 (11 January 2007),* paragraph 64.

[97] *Re Vodafone Network Pty Ltd & Vodafone Australia Limited [2007] ACompT 1 (11 January 2007),* paragraph 84.

The AER notes that the first reference to the term 'workably competitive market' in a regulatory context was in the matter of *Re Michael*, by the Supreme Court of Western Australia.

This concept and language was adopted by the AEMC in its final rule determination on chapter 6A, where it stated in relation to operating, capital and service performance incentives:

> The role of incentives in regulation can be traced to the fundamental objective of regulation. That is, to reproduce, to the extent possible, the production and pricing outcomes that would occur in a workably competitive market in the circumstances where the development of a competitive market is not economically feasible.[98]

In comparing incentive regulation to cost-of-service regulation, the AEMC stated:

> While cost-of-service regulation is based on remunerating TNSPs in respect of their *actual* costs, incentive regulation is based on remunerating TNSPs in respect of their *forecast* costs over the regulatory control period (which is typically three to five years). Because TNSPs are able to capture a proportion of the benefits of any unanticipated cost reductions (and must absorb unanticipated cost increases) that occur during a regulatory control period, they are encouraged to make cost savings. At the end of the period, the actual costs in this period may be used as a *basis* for establishing the reasonableness of the cost estimates provided by the TNSP in the subsequent regulatory period. In this way consumers share the benefits of the efficiency gains secured by the TNSP, just as in a competitive market cost savings are ultimately passed to consumers as lower prices.[99]

The AEMC also noted that a key consideration in designing an incentive regime is the strength of the individual and suite of incentive mechanisms. It further stated:

> The extent to which TNSPs are allowed to benefit from the efficiency gains (and bear the risk of efficiency losses) that occur during a regulatory control period determines the strength or 'power' of the relevant incentive regime: a high-powered regime allows TNSPs to retain a relatively large share of the benefits, while a low-powered regime allows them to retain a smaller share.[100]

After having noted that replicating the pricing outcomes of the workably competitive market is the fundamental objective of regulation, considering that in a competitive market efficiencies are ultimately passed back to consumers, and noting that the extent to which service providers retain a share of past efficiency gains was a key consideration, the AEMC set up a framework whereby:

- the benefit of operating efficiencies were to be retained by service providers for a period to be determined by the AER following consultation—with the AER adopting a period of six years (five years in addition to the year the efficiency is realised), and

[98] AEMC, *Rule Determination—National electricity amendment (Economic regulation of transmission services) rule 2006 No.18*, 16 November 2006, p.93.
[99] AEMC, *Rule Determination—National electricity amendment (Economic regulation of transmission services) rule 2006 No.18*, 16 November 2006, p.93.
[100] AEMC, *Rule Determination—National electricity amendment (Economic regulation of transmission services) rule 2006 No.18*, 16 November 2006, p.94.

- the benefit of capital efficiencies were to be retained by service providers until the end of the regulatory control period in which they were realised.

Accordingly, the AER's position on the appropriate retention period for efficiencies realised by related party contractors is consistent with the AEMC's views on the expected pricing outcomes in a workably competitive market.

Importantly, the AER's approach ensures consistent regulatory treatment of all operating and capital efficiencies regardless of source. That is, regardless of whether the efficiencies are realised directly by the DNSP itself or its related party contractor. This treatment (assuming this is the treatment expected by DNSPs), in the AER's view, does not distort the business decisions of DNSPs and their related parties to structure their corporate groups and outsourcing arrangements on the basis of different regulatory treatments of efficiencies depending on the particular corporate structure adopted and subsequently 'game' the regulatory regime. In other words, the AER's approach 'sees through' a DNSP's corporate structure to ensure that past or future efficiencies are not afforded a different regulatory treatment purely on the basis of the particular corporate structure and pricing arrangements between related parties adopted by the DNSP's shareholders.

Other issues

The AER does not consider it has provided DNSPs with less than their efficient costs because of its interpretation of the prudency criteria. It is not clear to the AER how CitiPower and Powercor have reached this view on the AER's approach. That said, the AER does not agree with CitiPower's and Powercor's view that the capex criteria are competing. The AER considers these criteria are complementary. This is further discussed in chapter 7 (opex) and chapter 8 (capex).

The AER does not accept CitiPower's, Powercor's and JEN's position that the AER should ignore scale and scope efficiencies in providing standard control services which arise from a related party contractor providing other services to third parties, other related parties, and the provision of alternative control and negotiated services to the DNSP. Instead, the AER considers that by virtue of the related party providing standard control services to the DNSP, it is able to provide the other services to third parties at less than the standalone cost of providing those services. Given that both the standard control and the non-standard control services are provided at a lower cost by the fact that the related party is providing both sets of services, the AER considers it is reasonable that standard control services consumers share in the economies of scale and scope arising from this scenario.

AER conclusion

The AEMC's rule determination on chapter 6A does not suggest the AEMC intended the prudency criterion component 'in the circumstances' of the relevant DNSP to be restricted to the network operating circumstances or network characteristics of the relevant DNSP. The AER considers that the term 'circumstances' should be given its ordinary meaning which includes both the network operating circumstances and corporate structure and ownership circumstances of the relevant DNSP.

The actions of each of the Victorian DNSPs (especially CitiPower, Powercor, JEN and SP AusNet) to outsource significant activities to centralised, specialist operators within their corporate structures appears consistent with good business practice. This is primarily because of the significant economies of scale and scope that each of these operators can achieve through operating multiple networks. The fact that significant economies of scale and scope have been achieved is not in dispute.

Accordingly, the AER's concerns are not over the Victorian DNSPs' corporate structures, per se, but rather over the pricing arrangements agreed to by the Victorian DNSPs and these related party contractors. Specifically, whether these pricing arrangements reflect efficient costs and costs that a prudent operator in each of the Victorian DNSPs' circumstances would incur.

Through each of the Victorian DNSPs outsourcing to their related party contractors (and in several cases this involved the transfer of staff to the often newly formed related party contractor), the Victorian DNSPs have directly contributed to and increased the workload of the related parties, and consequently, contributed to the economies of scale and scope realised by their related parties. That is, but for the work received from the Victorian DNSPs their related parties would be smaller and would likely enjoy lesser economies of scale and scope. Generally speaking, it would not be a good and prudent business practice to give away 'something for nothing'. Accordingly, good and prudent business practices would suggest that as the Victorian DNSPs have contributed to the scale and scope economies of their related parties, then they should share in at least some of those efficiencies in the pricing arrangements struck between the parties.

The AER expects that a prudent operator would not agree to continue to pay a contractor standalone, in-house costs (the costs it incurred pre-outsourcing), and would only agree to pay something less than this amount as it would require that it receives a share of the contractor's economies of scale and scope (which it has helped the contractor achieve by virtue of it outsourcing activities to the contractor).

Following on from this, the AER considers that the prudency criterion suggests the appropriate cost standard is some amount less than 'standalone, in-house' costs, and that the efficiency criterion provides more precise guidance for how much less than standalone, in-house costs is appropriate.

It appears to be generally accepted by the Victorian DNSPs that the expected pricing outcomes from a workably competitive market is an appropriate framework to consider the meaning of efficient costs. There is also general acceptance that in a workably competitive market a contractor cannot continue to earn a margin above its full economic costs (that is, earn abnormal profits) for efficiencies it has realised in the past. The issue in contention is over what time period this pass back of historical efficiencies to consumers would be expected to occur in a workably competitive market.

As an aside, the AER notes there appears to be an inconsistency between CitiPower's, Powercor’s and JEN's acceptance that in a workably competitive market the benefit of historical efficiencies cannot be retained indefinitely by a contractor, and their position that any contract charge with their related parties up to and including standalone cost should be acceptable under the NER. Given their related parties operate multiple networks and have realised significant historical scale and scope efficiencies, it follows that CitiPower, Powercor and JEN should agree that standalone cost would not be an acceptable cost standard as it does not acknowledge that in a workably competitive market their related parties could not retain the benefit from these efficiencies indefinitely.

The AER has adopted a retention period of five years for operating efficiencies and until the end of the regulatory control period for capital efficiencies. This is consistent with the regulatory framework set up by the AEMC for the treatment of efficiencies. And in setting up this framework the AEMC acknowledged that the fundamental goal of incentive regulation was to replicate a workably competitive market. The AEMC also stated that in a competitive market historical efficiencies are eventually passed through to consumers.

The AER has reviewed the margin benchmarking submitted by CitiPower, Powercor and JEN. The AER notes that this margin benchmarking does not suggest a particular retention period and so it is not clear that the AER's retention periods are not a reasonable approximation of observed commercial practice. The AER also noted three studies referred to by the Queensland Competition Authority (QCA) is setting up its efficiency carryover mechanism which suggest that in commercial reality firms do not retain the benefit of efficiencies for longer than five years.

In section 6.5.5.3 the AER has also reviewed the Australian Taxation Offices (ATO) guidelines material submitted by CitiPower and Powercor, but considers that the different objectives of the tax and economic regulatory regimes means that related party transactions made under the ATO guidelines should not be assumed to automatically also meet the NER requirements.

Accordingly, while the AER has had regard to the margin benchmarking and ATO material it has not persuaded the AER to depart from the retention periods which are consistent with the treatment of efficiencies realised by DNSPs. The AER considers consistency between the treatment of efficiencies realised by related parties and consistency between the treatment of efficiencies realised by DNSPs themselves to be an important consideration. The AER considers these retention periods are consistent with the expected pricing outcomes from workably competitive market.

The interaction with the EBSS is also important to recognise. The AER's approach results in historical operating efficiencies being rewarded through the EBSS. This approach is appropriate because the AER can not reasonably rely on the DNSPs and their related parties to pass back efficiencies to consumers in an appropriate timeframe. The AER also considers the dividing up between the DNSP and its related party of the benefit from historical efficiencies is a matter entirely up for them to decide. The AER is concerned about when consumers share in these benefits, not the dividing up of the benefit between the DNSP and related party before it is passed back to consumers.

Finally, the AER considers the adoption of a standalone cost standard is not consistent with the NEO as while it would promote efficiencies, it would not promote efficiencies in the long term interests of consumers as consumers would not share in these efficiencies. The AER's retention periods ensure DNSPs and related party contractors are provided with effective incentives—in accordance with the relevant revenue and pricing principles—to pursue efficiencies (because they get to keep the benefit for a period of time) while also promoting the NEO because consumers share in the benefit of the efficiencies.

6.5.3.6 Incentive effects of AER's framework

CitiPower, Powercor and JEN all argue that the AER's approach provides a perverse incentive for DNSPs to bring internally functions which are currently outsourced, even where outsourcing is the lower cost solution.

The AER does not agree. The AER's approach allows DNSPs and their related party contractors to retain the benefit of efficiencies realised by the related party contractor for a period of time, but after that time for that benefit to be passed on to consumers.

As the AEMC noted in drafting chapter 6A:

> While cost-of-service regulation is based on remunerating TNSPs in respect of their actual costs, incentive regulation is based on remunerating TNSPs in respect of their forecast costs over the regulatory control period (which is typically three to five years). Because TNSPs are able capture a proportion of the benefits of any unanticipated cost reductions (and must absorb unanticipated cost increases) that occur during a regulatory control period, they are encouraged to make cost savings. At the end of the period, the actual costs in this period may be used as a basis for establishing the reasonableness of the cost estimates provided by the TNSP in the subsequent regulatory period. In this way consumers share the benefits of the efficiency gains secured by the TNSP, just as in a competitive market cost savings are ultimately passed to customers as lower prices.

The AER's approach to the assessment of outsourcing and related party transactions affects the timing that benefits are passed through to consumers (to ensure that the timing is the same as that of other operating and capital efficiencies) but does not prevent DNSPs and their related parties from benefiting from those efficiencies for a period of time, with that time being:

- operating efficiencies are retained for five years in addition to the year they are realised, and
- capital efficiencies are retained until the end of the regulatory control period in which they are realised.

As DNSPs and their related parties will continue to share in the benefits from the scale, scope and other efficiencies realised by the related party outsourcing for a period of time, contrary to the statements of CitiPower, Powercor and JEN, the AER's approach does not provide a perverse incentive to inefficiently internalise functions that could be more efficiently outsourced.

6.5.3.7 Previous regulatory decisions

CitiPower, Powercor and JEN have identified the following instances which they believe demonstrate an inconsistency between the AER's approach to outsourcing and related party transactions in the draft decision and other previous regulatory decisions:

- the ESCV's last GAAR which concluded that contract charges could still be accepted as efficient where it could be demonstrated that the charges were less than or equal to the costs of 'in-house' provision by the service provider[101]

- a prior telecommunications judgement where the Tribunal considered that the standalone, in-house cost of service provision is the cost benchmark that best reflects the pricing outcomes that would prevail in a workably competitive market[102]

- the AER's draft decision for ETSA Utilities which accepted PB Consulting's recommendation that ETSA Utilities' contract charges with CHED Services were efficient because the contract resulted in 'lower costs than providing the services in-house on a stand alone basis', and[103]

- the conclusions in the AER's JGN final decision as discussed below.

JEN alone has submitted that the AER's approach to outsourcing and related party transactions in the draft decision is inconsistent with:

- the AER's final decision for ActewAGL which accepted the entire margin paid to JAM in the opex forecast,[104] and

- the AER's approach to equity and debt raising costs in the draft decision where it assessed the forecasts against that of a 'benchmark firm' that, among other aspects, the AER considered was a firm 'without parent ownership'.[105]

These issues are considered in the following section.

ESCV—Gas access arrangement review

The AER has, in developing its approach, had regard to the work done by the ESCV in the 2006 EDPR and the GAAR, as well as having regard to the reports by economic consultants commissioned by both the ESCV and service providers in the context of those reviews.[106] CitiPower and Powercor have acknowledged this.

The starting point for assessing contracts that do not pass the presumption threshold under both the ESCV's and AER's frameworks, is the contractor's direct costs of providing the service. Similarly, under both frameworks, these costs are adjusted upwards to incorporate a return on assets employed by the contractor or an appropriate portion of common or overheads costs if such costs have not already been included.

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[101] CitiPower, *Revised regulatory proposal*, pp.143-144; Powercor, *Revised regulatory proposal*, pp.133-134; JEN, *Revised regulatory proposal*, pp.66-68.
[102] CitiPower, *Revised regulatory proposal*, p.139; Powercor, *Revised regulatory proposal*, pp.131-132; JEN, *Revised regulatory proposal*, pp.78-79.
[103] CitiPower, *Revised regulatory proposal*, p.147; Powercor, *Revised regulatory proposal*, p.137; JEN, *Revised regulatory proposal*, p.77.
[104] JEN, *Revised regulatory proposal*, pp.83-84.
[105] JEN, *Revised regulatory proposal*, p.77.
[106] CitiPower, *Revised regulatory proposal*, p.143; Powercor, *Revised regulatory proposal*, p.133.

However, CitiPower, Powercor and JEN pointed out that the ESCV also allowed an upwards adjustment if an efficient and prudent service provider could not undertake the activities at the same cost as incurred by the contractor. That is, the ESCV in the GAAR adopted an 'in-house' cost benchmark to assess contracts that do not pass the presumption threshold. The ESCV stated there were various ways a service provider could demonstrate the contract charge was less than the costs the service provider would likely incur if it undertook the activities itself, including:

- producing evidence that it considered this factor when it entered into the contract and weighed up the alternatives before entering into the contract
- identifying economies of scale, scope or other efficiencies that are available to the contractor that are not available to it, and
- producing evidence that shows that if it undertook the activities itself its costs would be higher than the contract payments.

CitiPower and Powercor stated that the ESCV's adoption of an 'in-house' cost test in the GAAR was one of the more fundamental changes from EDPR, while JEN similarly described it as 'perhaps the most significant change'.[107] CitiPower and Powercor stated:

> While the AER appears to have drawn heavily upon the work on the presumption threshold undertaken in the context of the GAAR, it has essentially gone back to the position adopted by the ESCV in its 2006–10 EDPR in respect of the stage two assessment required where a contract fails the presumption threshold and assumed that the contractor's costs (including a share of overheads and return on and of physical assets) should be used as the basis for determining forecast opex and capex.[108]

CitiPower and Powercor argued that stage 2B of the AER's framework should be amended to bring it in line with the with the ESCV's approach in the GAAR.[109]

In the draft decision, the AER acknowledged the ESCV's significant contribution in the area of the appropriate regulatory treatment of outsourcing and related party transactions and the fact that the AER's framework is sourced from the previous work of the ESCV or consultants commissioned by either the ESCV or service providers during past ESCV resets. However, as stated in the draft decision, the one area where the AER has departed from the ESCV's approach is in respect of the in-house cost standard.[110]

In response to CitiPower's, Powercor's and JEN's submissions regarding departing from the ESCV's in-house cost standard, the AER notes it is not clear why the ESCV departed from its position in the EDPR to adopt the in-house cost test in the GAAR.

[107] CitiPower, *Revised regulatory proposal*, p.143; Powercor, *Revised regulatory proposal*, p.133; JEN, *Revised regulatory proposal*, p.66.
[108] CitiPower, *Revised regulatory proposal*, p.146; Powercor, *Revised regulatory proposal*, p.136.
[109] CitiPower, *Revised regulatory proposal*, p.148; Powercor, *Revised regulatory proposal*, p.138.
[110] AER, *Draft decision*, p.179.

Further, in the draft decision the AER stated that the ESCV's 'in-house' cost test did not appear to be equivalent to a 'fully in-sourced network' cost test.[111] The AER took this inference from the ESCV's statement that one of the factors it would consider relevant to its assessment, being:

> …whether the contractor is able to provide the outsourced activities at lower cost than the distributor *could obtain elsewhere. [emphasis added]*

Neither CitiPower, Powercor or JEN responded to this draft decision statement in their revised proposals.

Tribunal—Optus DGTAS judgement

CitiPower, Powercor and JEN submitted that the Australian Competition Tribunal (the Tribunal) in *Application by Optus Mobile Pty Limited and Optus Networks Pty Limited* established that, in a workably competitive market, a service provider may gain a competitive advantage by having access to economies of scale and scope and by reason of its ownership and operation of other networks in addition to the regulated network such that the standalone, in-house costs of service provision is the cost benchmark that best reflects the pricing outcomes that would prevail in a workably competitive market.[112]

This is discussed further in section 6.5.3.4.

AER—ETSA Utilities draft decision

JEN submitted that in prior regulatory decisions, the AER applied the standalone counterfactual when assessing expenditure forecasts. JEN stated:

> A recent example of this inconsistency can be found in the AER's *Draft Decision – South Australia distribution determination 2010-11 to 2014-15*. In this draft decision, the AER endorsed the use of the stand alone test employed by its consultant PB Associates, when considering the outsourcing arrangements entered into by ETSA Utilities and its related party, CHED Services.[113]

While JEN stated that the AER has applied a standalone cost counterfactual when assessing forecast expenditure, the AER notes that the only example of this JEN identifies is in the treatment of one opex cost category in the ETSA Utilities draft decision.[114] CitiPower and Powercor also identified this inconsistency.[115]

The AER notes that issue of whether a standalone cost standard is appropriate in assessing expenditure forecasts was not a focus of PB Associates' review or the AER's ETSA Utilities draft decision, whereas this issue has been reviewed in detail in the context of the Victorian electricity distribution determination. The AER's considered opinion on this matter is that set out in this review.

[111] AER, *Draft decision*, pp.179-180.
[112] CitiPower, *Revised regulatory proposal*, p.139; Powercor, *Revised regulatory proposal*, p.129; JEN, *Revised regulatory proposal*, pp.78-79.
[113] JEN, *Revised regulatory proposal*, p.77.
[114] JEN, *Revised regulatory proposal*, p.77.
[115] CitiPower, *Revised regulatory proposal*, p.147; Powercor, *Revised regulatory proposal*, p.137.

AER—JGN final decision

CitiPower and Powercor submitted that the AER appears to have regard to the principles referred to in the JGN draft decision but not the actual decision to allow a margin in the JGN final decision.[116] In particular, CitiPower and Powercor submitted that the AER:

- did not assess whether the margin reflected the amount required by the contractor to recover a reasonable share of its overheads, a return on and of capital invested in physical assets and / or an allowance for asymmetric risks, and
- appears to have instead made its assessment on the basis of benchmark studies.[117]

JEN stated that the inconsistencies with the JGN final decision are that while the AER rejected the margin paid to JAM on services sub-contracted by JAM, the AER also acknowledged that the payment of a margin to a contractor was:

- 'not inconsistent with' the relevant provisions of the National Gas Rules (NGR)
- appropriate at a level consistent with the implicit margin arising from JAM's revealed costs in the 2008–09 base year, and
- 'consistent with the benchmarking evidence' at the level it determined.[118]

The AER notes firstly that, in the draft decision, it did not refer to the JGN final decision because at that time the JGN final decision had not been published.[119]

Secondly, the AER notes that CitiPower, Powercor and JEN have not recognised that both the Victorian draft decision and JGN final decision, in relation to overhead margins:

- considered overhead margins (in the form of flat percentages rates added to direct costs) are not appropriate unless they are supported by evidence of consistency with underlying historical incurred indirect costs[120]
- excluded the same enterprise support function (ESF) costs allocated from Jemena Ltd (Singapore Power management fee, financial strategy, investment analysis, energy investments) and rejected these costs for similar reasons.[121]

Additionally, in relation to profit margins, both decisions:

- stated related party contract prices (underlying cost plus profit margin) could be demonstrated as efficient if the result of a competitive tender process[122]

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[116] CitiPower, *Revised regulatory proposal*, p.143; Powercor, *Revised regulatory proposal*, p.133.
[117] CitiPower, *Revised regulatory proposal*, p.147; Powercor, *Revised regulatory proposal*, p.137.
[118] JEN, *Revised regulatory proposal*, p.83.
[119] AER, *Final decision—Public—Jemena Gas Networks—Access arrangement proposal for the NSW gas networks—1 July 2010 to 30 June 2015*, 11 June 2010. The Victorian draft decision was published on 4 June 2010.
[120] AER, *JGN final decision*, pp.51-52.
[121] AER, *JGN final decision*, pp.247-254.

- considered overall comparative cost benchmarking is not a good basis to demonstrate the efficiency of a margin

- considered the margin in contracts that JAM provides to other parties is not a good benchmark due to difficulties in ensuring comparability between arrangements[123]

- the JGN decision excluded margins where the related party further outsourced the service to another party. While this test is not explicitly part of the Victorian draft decision approach, the outcome is consistent with the outcomes under the Victorian draft decision approach (this was also noted in the Victorian draft decision)[124]

Thirdly, the AER's decision to accept part of the margin paid to JAM was not on the basis of benchmark studies, as stated by CitiPower and Powercor. JEN's summary of the AER's position in the JGN final decision also overstates the emphasis placed on margin benchmarking studies by the AER. To clarify, the AER's decision to accept part of the margin in the JGN final decision was based on the consistency of the margin with the implicit margin arising from JAM's revealed costs in the 2008–09 (a 'revealed margin' approach)—as acknowledged by JEN.

While the AER noted the consistency between the JAM margin and the results of certain benchmarking studies, this consistency was not itself a reason the AER accepted the margin in the JGN final decision.

The reason the AER assesses margins in contracts that do not pass the presumption threshold (such as in a contract with a related party contractor) is because in that circumstance both the service provider and the related party contractor have an incentive to agree to a contract price that is greater than arm's length terms. The existence of this incentive is accepted by CitiPower, Powercor and JEN.

The AER's approach in the JGN final decision was to compare the margin in the future JAM contract (which the AER had concerns with because of the same incentive effects just stated) with the implicit margin—that is, the difference between the contract price and JAM's actual costs—from the current JAM contract.

The AER has since reassessed its position on accepting a margin based on consistency with a historical implicit margin. The AER acknowledges the differences in aspects of the approach to assessing outsourcing arrangements in the Victorian draft decision and JGN final decision. The AER has further considered the approaches in both decisions and taken into account the views of CitiPower, Powercor and JEN in this regard. The AER's considered position on the appropriate approach to assessing outsourcing arrangements for the purposes of assessing opex and capex forecasts under the NEL and NER is that set out in this chapter.

AER—ActewAGL final decision

Comparing the draft decision to both the ActewAGL and JGN final decisions, JEN stated:

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[122] AER, *JGN final decision*, p.267.
[123] AER, *JGN final decision*, p.271.
[124] AER, *JGN final decision*, pp.55, 268.

> While each of these decisions was made under the NGR and the National Gas Law, the operating and capital expenditure criteria are broadly similar to those specified in the Rules. One would therefore expect some consistency in the approaches employed in the regulation of both gas pipelines and electricity networks. The AER's rationale for applying a different approach to the Victorian DNSPs to that employed in these two decisions has not been made clear in the draft decision. Nor has the AER explained why, when developing its proposed assessment framework, it considered the approach taken in the JGN draft decision but not the approach that was ultimately taken in the JGN final decision, which was released just one week after the AER's draft determination for JEN. The lack of consistency between these decisions and the absence of any reason for the difference in approach is, in JEN's view, peculiar and contrary to one of the Ministerial Council on Energy's principal objectives in implementing further reforms in the gas and electricity sectors, which was to develop a 'common approach to revenue and network pricing across the energy market'.[125]

The AER acknowledges that it did accept the full margin paid to JAM in ActewAGL's opex forecast. At the time of the ActewAGL access arrangement review the AER had not yet formed a considered view on the appropriate approach to the assessment of outsourcing and related party transactions. The JGN access arrangement review was the first time the issue of related party transactions was material and so resulted in a substantial evaluation by the AER. The Victorian electricity distribution determination was the second such review.

The AER's approach to the issue of related party transactions has continued to evolve as its understanding of factors involved and ability to assess information provided has increased. The AER's understanding of the appropriate specification of regulatory information notices (RINs) in order thorough assess service providers' related party transactions has also increased.

As noted above, the AER has since reassessed its position on the appropriate approach to outsourcing and related party transactions from that set out in the ActewAGL and JGN final decisions.

On the information currently before the AER, after having considered the submissions from the Victorian DNSPs and other stakeholders, and for the reasons set out in this chapter, the AER has maintained the approach from its Victorian draft decision in this final decision. The AER intends to consider this same approach in future regulatory determinations.

AER—Victorian electricity distribution draft decision

JEN argued that the AER's approach to related party transactions in the draft decision was inconsistent with its approach to assessing equity and debt raising costs, notwithstanding the same opex and capex criteria are relevant to both issues. JEN stated:

> When assessing the compliance of the Victorian's proposed equity and debt raising costs with the opex and capex criteria, the AER has based its assessment on a 'benchmark firm', which it describes as a 'pure play regulated electricity network operating in Australia without parent ownership'. The position taken by the AER on ownership in this context is in direct contrast to the position it has taken with respect to outsourcing

[125] JEN, *Revised regulatory proposal*, p.84.

> arrangements, notwithstanding the application of the same opex and capex criteria.[126]

That is, JEN argued that although the AER's position was that a hypothetical 'standalone' network cost standard was not appropriate for the purposes of assessing outsourcing arrangements under the opex and capex criteria, the AER's approach to equity and debt raising costs supports a standalone cost standard and is therefore inconsistent.

The AER does not agree. The benchmark efficient firm definition adopted in the draft decision assessment of equity and debt raising costs originated from the AER's WACC review. In the WACC review explanatory statement (released with the proposed WACC parameters), the AER stated:

> The AER considers that the efficient benchmark is a 'pure play' electricity network business rather than a standalone network…[127]

In the WACC review final decision, the AER slightly revised this definition as follows:

> The AER considers that the concept of the benchmark efficient NSP is a 'pure play' regulated electricity network business operating within Australia without parent ownership.[128]

The reference to 'without parent ownership' was included in response to submissions on the issue of competitive neutrality, and to clarify that the AER was not treating government owned and privately owned service providers differently. It was not intended to express a view on the treatment of economies of scale through operating multiple networks. In the final decision the AER maintained its adoption of the term 'pure play' network and again rejected the term 'standalone' network from the definition of the benchmark efficient firm.[129]

To clarify, the AER has applied the same opex and capex criteria in its assessment of outsourcing arrangements and to its assessment of debt and equity raising costs. In the assessment of debt and equity raising costs, the AER considers the benchmark expenditure factor to be particularly relevant. The AER's assessment of debt and equity raising costs is set out in appendices N and O, respectively.

6.5.4 Alternative frameworks proposed by Victorian DNSPs

6.5.4.1 CitiPower and Powercor revised regulatory proposals

CitiPower and Powercor suggested that the AER's framework should be amended to bring it into line with the approach taken by the ESCV in the GAAR. Specifically, stage 2B of the AER's framework should be amended to recognise the potential for

[126] JEN, *Revised regulatory proposal*, p.77.
[127] AER, *Explanatory statement—Electricity transmission and distribution network service providers—Review of the WACC parameters*, December 2008, p.56.
[128] AER, *Final decision—Electricity transmission and distribution network service providers—Review of the WACC parameters*, May 2009, p.82.
[129] AER, *Final decision—Electricity transmission and distribution network service providers—Review of the WACC parameters*, May 2009, pp.79-82.

the price payable under a contract that fails the presumption threshold (including any explicit or implicit margin) to comply with the opex and capex criteria:

> …where it can be demonstrated that the contract price is less than or equal to the in-house cost of provision, where the in-house cost of provision is measured by reference to the stand-alone counterfactual.[130]

CitiPower and Powercor stated that the framework should also provide guidance to a DNSP on the types of evidence that may satisfy the AER that the contract price is less than the in-house cost. CitiPower and Powercor argued that, consistent with the ESCV's position, one or more of the following types of evidence should be sufficient:

- documentary evidence from the time the contract was entered into that demonstrates that the DNSP considered whether the contract would lower its overall costs and that it weighed up the alternatives before entering into the contract

- information on the economies of scale, scope and/or other efficiencies that would be available to the contractor that would not otherwise be available to the DNSP, or

- evidence that demonstrates that if the DNSP undertook the activities itself the costs would be higher than the contract payments.[131]

Where a DNSP is able to demonstrate that the contract price is lower than the in-house cost of provision, CitiPower and Powercor argued that the contract price should be accepted as representing the appropriate basis for determining the opex and capex forecast, subject to the two further assessments that apply to contracts that pass the presumption threshold under the AER's framework (that is, the contract relates wholly to the provision of the relevant services and there is no double-counting of costs or risks between the contract price and other aspects of the DNSP's building block proposal). In other words, CitiPower and Powercor proposed that the contract moves from stage 2B to stage 2A of the AER's framework.[132]

Where a DNSP is unable to demonstrate this, CitiPower and Powercor stated that the AER should utilise the in-house cost estimate in the derivation of forecast opex and capex.[133]

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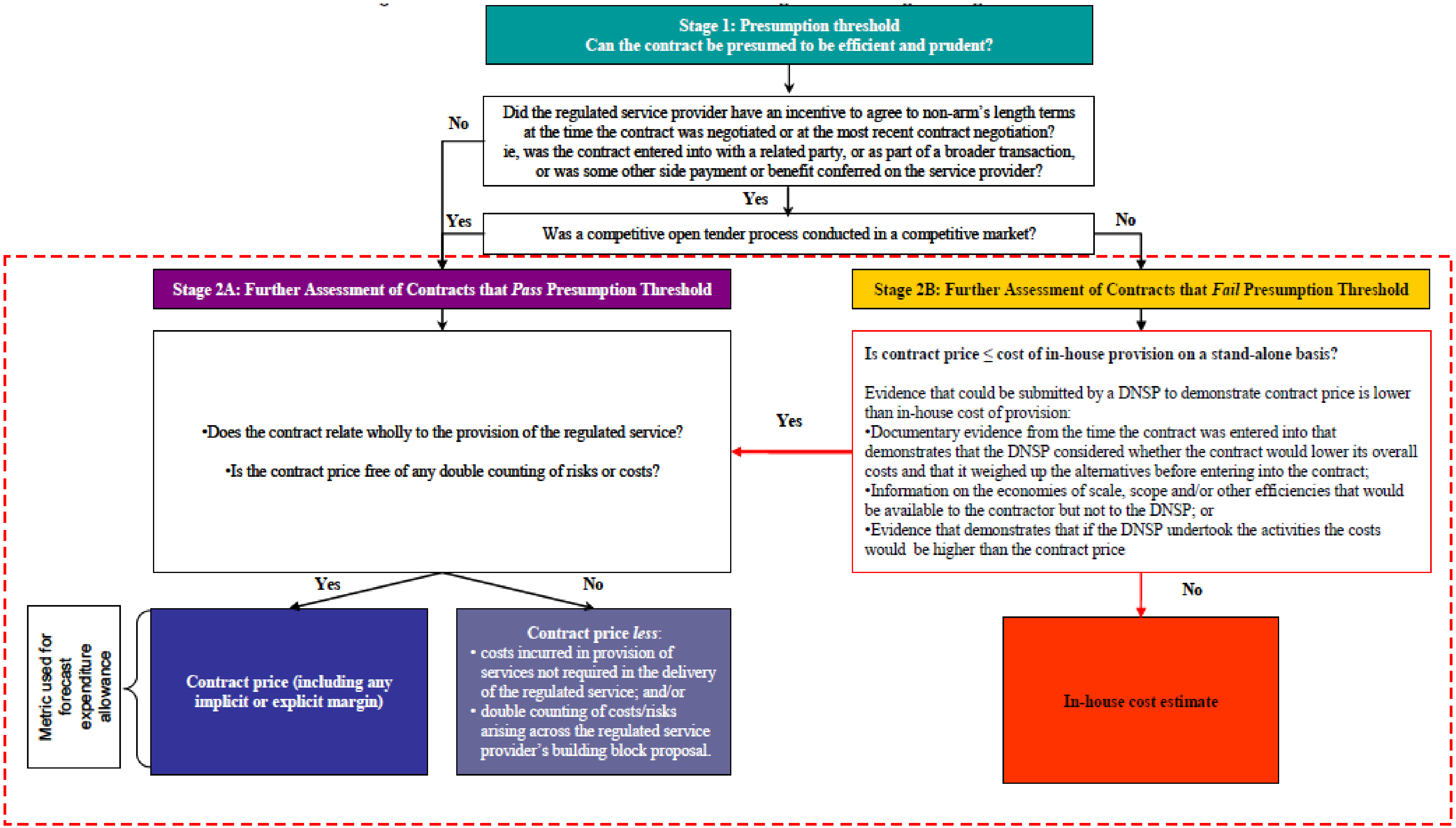
130 CitiPower, *Revised regulatory proposal*, p.148; Powercor, *Revised regulatory proposal*, p.138.
131 CitiPower, *Revised regulatory proposal*, p.148; Powercor, *Revised regulatory proposal*, p.138.
132 CitiPower, *Revised regulatory proposal*, pp.148-149; Powercor, *Revised regulatory proposal*, p.138.
133 CitiPower, *Revised regulatory proposal*, p.149; Powercor, *Revised regulatory proposal*, p.138.

Figure 6.2 CitiPower and Powercor—Proposed assessment of outsourcing and related party transactions



Source: CitiPower, *Revised regulatory proposal*, p.150; Powercor, *Revised regulatory proposal*, p.139.

Other factors CitiPower and Powercor considered could inform the AER's assessment of contracts that fail the presumption threshold are:

- the non-price terms and conditions, with particular emphasis placed on:
  - the level of control accorded to the DNSP over the expenditure incurred by the contractor and other governance arrangements contained in the contract
  - the extent to which the contract accords the contractor with an incentive to lower costs and pass those reduced costs on to the DNSP, and
  - the risks accorded to the contractor under the contract, and
- comparative benchmark analysis—while CitiPower and Powercor conceded that some care must be taken with benchmark studies, they believe such studies still have a role to play particularly when they form part of a broader submission that demonstrates that the price payable under the contract does not exceed the level that would be incurred if the services were provided in-house.[134]

6.5.4.2 JEN revised regulatory proposals

JEN also proposed the AER's assessment of contracts that fail the presumption threshold (stage 2B) be modified to bring it into line with the approach adopted by the ESCV in the GAAR. Using the same words as CitiPower and Powercor, JEN proposed:

> Specifically, the framework should be modified to recognise the potential for the contract price to still be consistent with the operating and capital expenditure criteria in the Rules, where a DNSP is able to demonstrate that the contract price is equal to or lower than the costs that would be incurred if the services were provided in-house, where the in-house cost of provision is calculated by reference to the stand-alone counterfactual.[135]

JEN argued that if a DNSP is able to demonstrate that this is the case, then, in the absence of further evidence or material, the contract price should form the basis for:

- the DNSP's forecast operating and / or capital expenditure, and
- the measurement of operating expenditure used in the EBSS.[136]

If a DNSP is unable to demonstrate this is the case then, consistent with CitiPower's and Powercor's proposed framework, the in-house cost estimate should form the basis of the expenditure forecasts.

Following the ESCV's approach in the GAAR, JEN proposed that the contractor's direct costs be used as the starting point for estimating the cost of in-house provision, with additional allowances to reflect:

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[134] CitiPower, *Revised regulatory proposal*, p.151; Powercor, *Revised regulatory proposal*, p.140.
[135] JEN, *Revised regulatory proposal*, p.86. While JEN states this may not be the only way that costs could be demonstrated as efficient, JEN does not describe other ways.
[136] JEN, *Revised regulatory proposal*, p.86.

- the return on and of assets required by the contractor for those assets that it owns and are used in the provision of services to the DNSP

- an appropriate portion of the contractor's common costs, and

- the economies of scale, scope and other efficiencies not otherwise available to the DNSP operating on a standalone basis.[137]

JEN considered that while ascribing a value to the first two of these items will be relatively straightforward, in practice it may not be possible to quantify, with any degree of precision, the value of efficiencies that are available to the contractor but not otherwise available to the DNSP. JEN stated it has therefore given further consideration to the other factors the AER could use to satisfy itself when assessing whether the contract price is likely to be less than the in-house cost of provision.[138]

JEN stated that one alternative, where the contract is based on a cost pass through pricing structure, would involve undertaking an inquiry to determine whether:

- the contractor's costs (both directly and indirectly incurred and an appropriate share of common costs) are lower than those that could be achieved by the in-house service provider operating on a stand alone basis, and

- the margin (defined in this context as an amount in excess of the contractor's directly and indirectly incurred costs and an appropriate share of common costs) is comparable to that charged by other contractors for similar levels of risk and does not exceed the expected benefits of the economies of scale, scope and other efficiencies offered by the contractor.[139]

JEN stated that the results of benchmark studies may provide further support for this inference where an outsourcing arrangement accounts for a substantial proportion of a DNSP's total expenditure. While conceding that benchmarking cannot itself be relied upon to demonstrate consistency with the opex and capex criteria, JEN argued it is a further piece of information that can provide greater insight into whether the total price payable under the contract is efficient and prudent.[140]

Other factors that JEN stated would be relevant are the contract's:

- non-price terms and conditions—comparing these against what would be expected in an arm's length contract, which would involve an assessment of the scope of services provided and governance arrangements (i.e. including an appropriate allocation of responsibilities and according the DNSP with sufficient control over its assets and expenditure)

- incentive arrangements—the AER could take comfort that the contractor's incentives are aligned with the NEO, revenue and pricing principles and the NER

[137] JEN, *Revised regulatory proposal*, pp.86-87.
[138] JEN, *Revised regulatory proposal*, p.87.
[139] JEN, *Revised regulatory proposal*, p.87.
[140] JEN, *Revised regulatory proposal*, p.87.

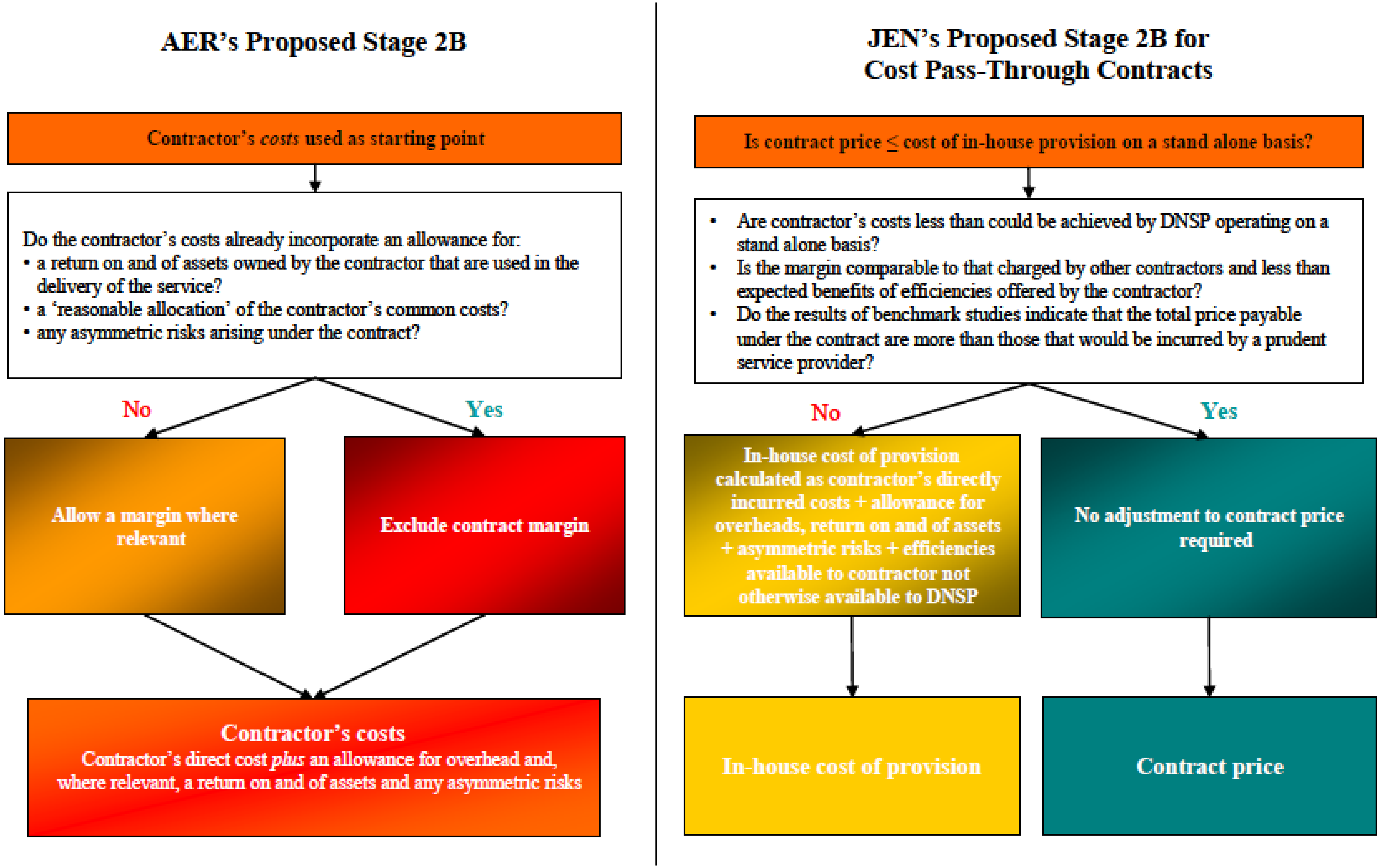
> if the contract provides the contractor with an incentive to pursue productive and dynamic efficiencies and pass those efficiencies back to the service provider.[141]

JEN stated that the ESCV had regard to both these factors in the GAAR.[142]

JEN did not recommend any amendments to the stage 1 or 2A of the AER's framework. JEN's proposed changes to the AER's stage 2B, as discussed above, is set out in Figure 6.3.

[141] JEN, *Revised regulatory proposal*, p.88.
[142] JEN, *Revised regulatory proposal*, p.88.

Figure 6.3 JEN—Proposed approach to outsourcing and related party transactions (amendments to stage 2B)



JEN, *Revised regulatory proposal*, p.89.

6.5.4.3 Issues and AER considerations

Central to CitiPower's, Powercor's and JEN's proposed frameworks is that the AER should adopt a 'standalone, in-house' cost standard against which to assess expenditure forecasts.

As explained in this chapter, the AER continues to consider that efficiencies realised by a related party contractor should be shared with consumers after a period of time. The sharing of the efficiencies between the service provider and the related party contractor in the first instance, is a matter entirely up to those parties to determine. However, after an appropriate period of time has lapsed the benefits from those efficiencies should be passed through to consumers.

The AER considers that adopting a 'standalone, in-house' cost standard is unlikely to promote the achievement of the NEO because it would prevent consumers benefiting from the economies of scale or scope realised by related party contractors. This would not be in the long term interests of consumers. Rather, to be in the long term interests of consumers, consumers need to benefit from efficiency gains either through, *ceteris paribus*:

- lower prices for existing levels of service security, safety, reliability and performance, or
- higher levels of service security, safety, reliability or performance, without any prices increases.

While a 'standalone, in-house' cost standard would promote efficiency, it would not promote efficiency in the long term interests of consumers, as consumers would not share in the realised scale or scope efficiencies of related party contractor through either lower prices or higher service levels.

The AER reaffirms its draft decision position that a standalone, in-house cost standard is not appropriate under the NEL and NER unless this represents the actual circumstances of the DNSP (taking into account its corporate structure).

The other cost build-up components proposed by JEN appear consistent with the AER's legitimate economic reasons for a margin (which refer to a return on and of certain assets, and corporate overheads).

The AER's position on benchmarking in the context of outsourcing and related party transactions is set out in section 6.5.5.

CitiPower, Powercor and JEN all promote the consideration of non-price terms in the contract, including whether the contract passes back some of the efficiencies realised by the contractor.

If a contract with a related party contractor includes a mechanism to pass back some of the efficiencies realised by the related party to the DNSP, then the AER considers this is a positive aspect of the contract. However, the inclusion of any mechanism is not sufficient to conclude that the contract design reflects the actions of a prudent operator in the DNSP's circumstances or that the DNSP pays only efficient costs.

The design of the EBSS is intended to result in a sharing ratio of past efficiencies between DNSPs and consumers of 30 per cent / 70 per cent in net present value terms, in favour of consumers. In contrast, a sharing mechanism in a related party contract could, hypothetically, effectively include a 90 cent / 10 per cent sharing between the contractor and the DNSP (and eventually consumers) or even a 99 per cent / 1 per cent sharing ratio. Clearly these sharing ratios are not equal, and should not be considered equally acceptable. That is, the mere presence of any sharing mechanism in a related party contract does not immediately mean that the ultimate sharing of efficiencies with consumers is sufficient. The AER considers that the sharing ratio prevailing in a workably competitive market is the ideal. As outlined in this chapter the AER considers this ratio would be consistent with an efficiency retention period of six years for operating efficiencies and until the end of the regulatory control period for capital efficiencies.

The AER also does not agree with that aspect of CitiPower's, Powercor's and JEN's proposed frameworks in which they propose that a contract price should be accepted if the DNSP is able to demonstrate the price is equal to or less than the standalone, in-house cost of providing the service. If the DNSP cannot demonstrate this, then the contract price should be replaced by an estimate of the standalone, in-house cost of providing the service. The AER considers this approach would appear to encourage DNSPs to poorly attempt to demonstrate that the contract price is *equal to or less than* the standalone, in-house cost, because if they fail to do this then the expenditure forecasts would be set *equal to* the standalone, in-house cost (that is, at a higher level).

Further, a practical difficulty in applying JEN's framework, is that JEN only endorses the application of its approach for cost pass through style contracts. So JEN's approach does not provide general guidance that the AER could apply to assessment of all contracts that fail the presumption threshold (or at least, not guidance which is endorsed by JEN).

6.5.4.4 AER conclusion

The frameworks proposed by CitiPower, Powercor and JEN are similar to that set out by the AER in the draft decision. The most significant change proposed is the adoption of a 'standalone, in-house' cost standard with which the AER does not agree. Therefore, the AER does not agree that the modifications proposed by CitiPower, Powercor and JEN are appropriate in assisting it in determining whether it is satisfied that the proposed related party margins in excess of overheads are consistent with a forecast opex or capex that reasonably reflects the opex or capex criteria.

6.5.5 Treatment of benchmarking

6.5.5.1 EBIT margin benchmarking

It is common practice for service providers to provide consultant's reports which benchmark the margins they pay to their related parties with earnings before interest and tax (EBIT) margins earned by contractors in the energy and other industries. JEN has submitted a number of such reports to the AER with its initial and revised regulatory proposals. CitiPower, Powercor and United Energy have also referenced or submitted such reports with their revised regulatory proposals.

AER draft decision

In the draft decision, the AER supported the ESCV's position on this matter and considered that it is the overall cost of providing the service which must be prudent and efficient, rather than simply the margin earned. The AER noted the ESCV's position from the GAAR 2008 final decision, that:

> …the mere presence of a margin that is consistent with industry benchmarks does not mean that the overall level of expenditure under the contract is itself consistent with the Code. The Commission outlined that if that were the case, there would be nothing to preclude a distributor simply restructuring its affairs to move its staff over to a related or associated party and entering into a contract at actual cost plus a margin. The result would simply be to inflate the costs that are recoverable from consumers by the level of the margin. The Commission noted that under this scenario, there would be nothing to preclude a series of cascading contracts in which each contractor in turn sub-contracted to another party at actual cost plus a 'margin'.[143]

The AER considered that whether or not a margin should be allowed, and the magnitude of that margin if allowed, should not simply be a matter of comparing the margin earned by a related party against industry benchmarks. Rather, the AER considered this is a case-by-case issue and includes consideration of the margin against the legitimate economic reasons for the inclusion of a margin. For example, whether or not a related party's corporate overheads are already included in the reported expenditure and whether it is utilising assets already in the service provider's RAB has an impact on the appropriate margin for that specific contract.

Victorian DNSPs' revised regulatory proposals

In its revised proposal, JEN stated that it:

> …agrees with the AER that in circumstances where a contractor owns and utilises its own assets in the provision of services, it would expect to earn a higher margin than contractors that do not own those assets.[144]

That said, CitiPower, Powercor and JEN contended that margin benchmarking studies demonstrate that, in practice, contractors earn margins in excess of the amounts that the AER has categorised as forming a legitimate basis for a margin, for periods exceeding five years.[145] CitiPower and Powercor argued that the most significant flaw in the AER's application of theory regarding pricing outcomes in workably competitive markets is that it fails to explain why this occurs.[146]

The main margin benchmarking studies referred to by CitiPower, Powercor and JEN are:

- NERA (commissioned by Envestra in the context of the last Victorian GAAR)—found that the average EBIT margin earned by contractors in its sample was 5.5 per cent between 2002–06, and

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[143] ESCV, *Gas access arrangement review 208-2012—Final decision—Public version*, 7 March 2008, p. 55.

[144] JEN, *Revised regulatory proposal*, p.93.

[145] CitiPower, *Revised regulatory proposal*, pp.139-142; Powercor, *Revised regulatory proposal*, pp.130-132; JEN, *Revised regulatory proposal*, p.80.

[146] CitiPower, *Revised regulatory proposal*, p.140; Powercor, *Revised regulatory proposal*, pp.130-131.

- Impaq (commissioned by the AER in the context of the draft decision to review the Victorian DNSPs' proposed alternative control services prices)—found in industries similar to alternative control services, profit margins of from 3 per cent to 8 per cent are common.

CitiPower and Powercor noted that EBIT margins represent the margin available to an entity after paying its directly incurred expenses, overheads and a return on capital invested in physical assets. CitiPower, Powercor and JEN stated that the samples in the NERA and Impaq studies use contractors with a relatively low proportion of assets in the derivation of revenue, implying that the observed EBIT margins are likely to be capturing more than the return on capital invested in these contractors' physical assets.[147] Following on from this, CitiPower and Powercor argued that the results of both NERA's and Impaq's studies:

> …suggest that either the AER's proposition does not hold in practice, or that there are factors, such as differences in the relative efficiency of contractors, supporting the payment of a margin above the contractor's directly incurred costs, overheads and a return on and of capital.[148]

JEN made similar comments to CitiPower and Powercor.[149] CitiPower and Powercor also referenced a comment made by Impaq that as alternative control services are not capital intensive the application of the standard building blocks of return on and of capital 'do not yield meaningful profit margins'.[150]

AER considerations and conclusion

The AER notes Impaq's view that the application of the building block approach does not provide meaningful profit margins in less capital intensive industries. However, the AER considers that standard economic and finance theory is that the primary interest of shareholders is to earn a return on the capital they have injected into a company that is commensurate with the shareholders' required rate of return for an asset with that level of systematic risk. The AER has not identified, nor have any stakeholders, any reasons why this premise would not still hold regardless of the capital intensity of a particular industry. The AER also notes the economic rational underlying the payment of a margin to a contractor was not a focus of Impaq's review.

Of particular interest are NERA's views on this issue which are central to CitiPower's, Powercor's and JEN's position on margin benchmarking. In the same report referenced by CitiPower, Powercor and JEN, NERA states that a margin in excess of a contractor's direct expenses may be prudently paid for reasons which are very similar to the AER's legitimate economic reasons. Specifically, NERA considers these reasons are:

- a share of the contractor's common costs
- a return on and of the capital owned by the contractor (that would otherwise need to be owned by the service provider),

[147] JEN, *Revised regulatory proposal*, pp.93-94.
[148] CitiPower, *Revised regulatory proposal*, p.141; Powercor, *Revised regulatory proposal*, p.131.
[149] JEN, *Revised regulatory proposal*, p.80.
[150] CitiPower, *Revised regulatory proposal*, p.140; Powercor, *Revised regulatory proposal*, p.131.

- expenses that cannot otherwise be directly passed through under the contract (for example, asymmetric risk), and

- the differences in the relative efficiency of the contractor and the service provider (which NERA refers to as the contractor's 'know-how').

On the role of margin benchmarking in the assessment of outsourcing arrangements, NERA stated:

> In general, it will not be possible to directly measure each of these factors. For example, it is difficult to measure the economic value of the contractor's 'know-how' or to determine a fair allocation of its common expenses. One way to test whether the size of a margin on a contract is reasonable is to compare it with the size of margins observed for other businesses providing comparable services to those provided under the contract. If the margin paid on the contract is within the range of margins earned by comparable businesses then the presumption should be, in the absence of any other powerful information to the contrary, that the payment of a margin is prudent.[151]

That is, NERA's report does not suggest that there are any 'missing factors' from the AER's list of legitimate economic reasons giving rise to a margin above direct costs. NERA's promotion of margin benchmarking is meant to be a 'proxy' for directly measuring each of these reasons. The AER has instead chosen to directly assess each of the components of the margin as it does not consider the task of assessing each component to be as complex as NERA suggests.[152] The AER also considers that in assessing contracts between parties that have an incentive to agree to non-arm's length terms, this greater level of scrutiny is warranted.

The main difference between the positions of NERA and the AER is that NERA adopts a cost standard similar to the standalone, in-house standard proposed by CitiPower, Powercor and JEN. That is, the difference is over the magnitude of the component of the margin reflecting 'know-how' which is acceptable. NERA stated a margin in excess of the contractor's direct expenses may be prudently paid if:

> The contractor's expenses are lower than those that would be incurred by providing the service in-house or through an alternative contractor.[153]

The AER notes that NERA does not appear to support the adoption of a standalone, in-house cost benchmark in all circumstances dues to its reference to '…or through an alternative contractor'. NERA appears to suggest that a prudent margin is the lower of the two. NERA also does not suggest that a contractor would require this payment in order for it to provide the service, rather NERA's comments are more in line with the AER's view that this reflects an 'abnormal profit' earned by the contractor. For example, NERA states:

> In this case, the existence of a margin is the ordinary response of commercial negotiations and will result in a total payment somewhere above the minimum price at which the contractor would be willing to accept the

[151] NERA, *Benchmarking contractor's profit margins—Envestra*, 28 March 2007, p.1.
[152] For example, an allocation of each of their related party contractor's common costs is determined each by the Victorian DNSPs and reported in their regulatory accounts.
[153] NERA, *Benchmarking contractor's profit margins—Envestra*, 28 March 2007, p.1.

> contract and somewhere below the businesses willingness to pay for the services.[154]

Ultimately, the issue here relates to what is the appropriate retention period for past efficiencies, and specifically whether the margin benchmarking studies presented by CitiPower, Powercor and JEN demonstrate that retention periods in commercial practice are longer than the six years for operating efficiencies and until the end of the regulatory period for capital efficiencies, as proposed by the AER in the draft decision.

The AER acknowledges that its proposed retention periods may not perfectly correlate with that observed in commercial practice. However, the AER considers it is important that there be consistency between the regulatory treatment of efficiencies realised by related party contractors and those realised by DNSPs themselves. That is, consistency generally with the standard regulatory treatment of operating and capital efficiencies under chapter 6. Further, it is not clear what retention period is suggested by NERA's average EBIT margin of 5.5 per cent or the other benchmarking studies referenced by the DNSPs.

The AER is also aware of other evidence that suggests the retention periods in observed commercial practice are similar to that adopted by the AER. Specifically, in developing its efficiency carryover mechanism, the Queensland Competition Authority (QCA) referenced the following empirical evidence, concluding that the period of above normal returns in actual competitive markets is generally limited to a maximum of five years:

- a study of 46 major product innovations found that the average time until entry by a competing product was around 3.4 years (Agarwal & Gort, 2001)
- a study of 500 brands in 50 product categories showed that market leadership ‘does not appear to last very long’ and the median period of leadership was only five years (Golder & Tellis, 1993), and
- even patented innovations are quickly imitated—a study of 48 successful patented product innovations from firms in chemical, drug, electronics and machine industries showed that the majority were imitated within four years (Mansfield et al, 1981).[155]

The AER acknowledges that the QCA references are not necessarily the most 'authoritative' evidence on observed market practice, however, nor is it necessarily any more reliable or authoritative than that presented by NERA and Impaq. However, the AER notes that to the extent there are differences in the results in these sets of market evidence, then this suggests a cautious approach in the interpretation and application of this data is prudent.

Accordingly, while the AER has had regard to the margin benchmarking presented by CitiPower, Powercor and JEN, the AER concludes that these benchmarking studies:

[154] NERA, *Benchmarking contractor's profit margins—Envestra*, 28 March 2007, p.1.
[155] Queensland Competition Authority, *Issues paper—Efficiency carryover mechanism*, September 2004, p.8.

- do not demonstrate that there are 'missing factors' in the AER's legitimate economic reasons for a margin—nor was this the intention of NERA is presenting this data, and
- do not demonstrate that the AER's adopted retention periods for past efficiencies are unreasonable or clearly at odds with observed commercial practice

6.5.5.2 Overall comparative cost benchmarking

Another way service providers may attempt to justify the payment of margins and the overall size of the contract in general is through the comparative cost benchmarking of the service provider's overall capex or opex costs (or ratio analysis based on these amounts) with those of other services providers.

AER draft decision

Where the contract provides only a portion of the services required by the service provider to operate its network, the AER considered overall comparative benchmarking provides little guidance as to the reasonableness of the contract price. The AER stated this position was consistent with its approach in the last SP AusNet transmission determination.

Alternatively, where the contract essentially covers the operation of the entire network, then the AER considered comparative cost benchmarking may be more valid. That said, the AER noted that while it has had regard to overall comparative cost benchmarking, it has not previously placed significant weight on this type of benchmarking given the difficulties in comparing different service providers (for example. due to differences in network characteristics or capitalisation policies).

Victorian DNSPs' revised regulatory proposals

CitiPower and Powercor stated that they understand the AER has some concerns about benchmark studies and the extent to which they can be relied upon to demonstrate compliance with the expenditure criteria in the NER. While CitiPower and Powercor agreed that some care must be taken with benchmark studies, they submitted that the studies still have a role to play, particularly when they form part of a broader submission that demonstrates that the price payable under the contract does not exceed the level that would be incurred if the services were provided in-house.[156]

JEN stated the results of benchmark studies may provide inference that the total price (inclusive of margin) paid to a contractor is less than the in-house cost of providing the service where an outsourcing arrangement accounts for a substantial proportion of a DNSP's total expenditure. JEN stated that it understands the AER has some concerns with the reliance that can be placed on benchmark studies and while JEN agrees that '…benchmarking can not, in and of itself, be relied upon to demonstrate consistency' with the expenditure criteria, it is a further piece of information that can provide greater insight into whether the total price payable under the contract is efficient and / or prudent.'[157]

[156] CitiPower, *Revised regulatory proposal*, p.151; Powercor, *Revised regulatory proposal*, p.140.
[157] JEN, *Revised regulatory proposal*, p.87.

AER considerations and conclusion

In the draft decision, the AER relied on comparative overall cost benchmarking in forming the view that the Victorian DNSPs' historical underlying costs (that is, exclusive of related party margins) were relatively efficient compared to that of other Australian DNSPs. The AER maintains that establishing the relative efficiency of these underlying costs is where this type of benchmarking is of most usefulness.

The AER notes that while acknowledging limitations to this type of benchmarking, CitiPower, Powercor and JEN argued that comparative overall benchmarking is one information source that can be used to establish that the DNSPs' contract prices are lower than standalone, in-house cost. The AER does not support this cost standard, as outlined in section 6.5.3.5.

In particular, the AER does not consider it is appropriate to use overall comparative cost benchmarking to prevent the sharing of historical efficiencies realised by related party contractors with consumers. For example, a related party contractor may be relatively more efficient in providing services than other DNSPs. If the maximum charge between DNSP and related party contractor that was permissible under the NER was the prevailing industry average (that is, the line of best fit in the overall comparative cost benchmarking) then the DNSPs and their related parties could retain the benefit of past efficiencies for longer periods than the AER considers appropriate under the NER, as set out in section 6.5.3.5.

6.5.5.3 Benchmarking against ATO guidance on 'arms length' related party transactions

CitiPower's and Powercor's initial regulatory proposals included reports from Ernst & Young (each focusing on different types of services, for example, corporate services) that were commissioned to establish 'arm's length' transfer prices applying methods accepted by the ATO with respect to the pricing of domestic and international related party transactions.

AER draft decision

Given the different objectives of the economic regulatory regime and the tax regime, the AER considered that it should not be assumed that practices which are appropriate in a tax context are always appropriate in an economic regulatory context.

For example, the AER noted that the ATO considers where 'special expertise' is being used by the related party contractor, one would normally expect a substantial mark-up in unrelated party transactions. Accordingly, the ATO considers a high margin in these related party transactions is acceptable. However, the AER considered that this was similar to the 'know-how' argument that had been put forward in an economic regulatory context to justify margins in related party contracts. In response to this argument for a related party margin, the AER considered that given the cost-based nature of the regulatory regime, consumers have already funded the acquisition of that know-how and so should now receive a share of the benefit when that know-how leads to efficiencies. Accepting a margin that fully reflects the value of that know-how would mean that consumers do not share in the benefit of the know-how, despite previously having funded its acquisition.

Victorian DNSPs' revised regulatory proposals

CitiPower and Powercor disagreed with the position taken by the AER on this issue and noted that, in a similar manner to the economic regulatory regime, the ATO's methods are designed to prevent any consideration passing between two related parties that would not be agreed by parties operating on an arm's length basis.[158]

According to CitiPower and Powercor, the ruling developed by the ATO on this provides guidance on when the costs associated with providing services to related parties should be recovered and when the costs should include a 'mark-up' on those costs. Where the provision of services to an associated entity confers a benefit on that entity then the arm's length charge should reflect the economic and commercial value of that benefit, including a margin.[159]

CitiPower and Powercor stated that the ATO's categorises services into:

- non-chargeable activities—activities of an entity that an unrelated entity would not be willing to pay for
- specific benefit activities—activities of an entity that an unrelated entity would pay for
- centralised services—services that benefit the related group as a whole (or a particular group of related subsidiaries) and must be apportioned and so a charge for the services would normally be made if the entities were dealing with each other on an arm's length basis[160]

CitiPower and Powercor stated that the methods accepted by the ATO for determining the arm's length charge include the comparable uncontrolled price (CUP) method and the cost plus (CP) method. CitiPower and Powercor stated that the CP method was used by Ernst & Young and states this method calculates an arm's length mark-up by analysing the profit earned on direct and indirect costs that companies providing comparable services to third parties earn.[161]

CitiPower and Powercor argued that such an analysis is just as relevant in an economic regulatory context as it is in a taxation context.[162]

AER considerations and conclusion

The AER agrees with CitiPower and Powercor that the ATO's categorisation of services is also appropriate in an economic regulatory context. Indeed, this reflects the approach adopted in the draft decision and maintained in this final decision. For example, the AER has rejected certain corporate costs on-charged from Jemena Ltd to JEN on the grounds that the costs primarily benefit the Jemena group's shareholders, not consumers, and are therefore not sufficiently connected to the provision of distribution services. This is consistent with the ATO's position on 'non-chargeable' activities.

[158] CitiPower, *Revised regulatory proposal*, p.167; Powercor, *Revised regulatory proposal*, p.156.
[159] CitiPower, *Revised regulatory proposal*, p.168; Powercor, *Revised regulatory proposal*, p.156-157.
[160] CitiPower, *Revised regulatory proposal*, p.168; Powercor, *Revised regulatory proposal*, p.157.
[161] CitiPower, *Revised regulatory proposal*, p.168; Powercor, *Revised regulatory proposal*, p.157.
[162] CitiPower, *Revised regulatory proposal*, p.169; Powercor, *Revised regulatory proposal*, p.158.

On the different objectives of the economic regulatory and taxations regimes, the AER notes the following.

Generally speaking, in markets where natural monopoly characteristics are not present the transactions between related parties cannot affect the final retail price to consumers. In competitive markets, prices are set external to the firm and cannot be affected by the actions of an individual firm. If a firm set its price above the equilibrium market price than, all else being equal, that firm will not be able to sell any output as consumers will migrate to other firms.

Whereas it is the natural monopoly characteristics of standard control services, and the monopoly power this confers on the DNSPs that gives rise to the AER's functions, and in particular, to ensure that prices are not set at a level where DNSPs earn monopoly profits. In this context, the AER is concerned about the incentive for DNSPs to agree to non-arm's length contract prices with related parties, resulting in higher regulated tariffs (if accepted by the AER) and monopoly profits earned by the DNSPs' shareholders.

Whereas, in the instances the ATO is concerned about the incentive to engage in transfer pricing is not caused by a goal of increasing final retail prices. Rather, the incentive is to reduce the overall tax paid by the corporate group by exploiting differences between tax regimes.

Consequently, the incentive in a tax context might be to under or over charge with this depending on the tax regime relativities. If Australia is a relatively high tax country (at least in terms of corporate tax rates) then the ATO would be primarily concerned with Australian companies undercharging their international related parties. The ATO's goal is to ensure that Australia receives its fair tax of corporate tax revenue rather than this revenue being lost to low tax countries.

In contrast, as noted above, the AER is concerned about DNSPs abusing their monopoly power and overcharging consumers, as well as ensuring that efficiencies are appropriately shared with consumers. Given these different objectives in the economic regulatory and tax regimes, the AER is not satisfied that related party transactions that meet the ATO's guidelines automatically meet the requirements of the NER.

Further, the AER notes the ATO's definition of the cost-plus method (the method adopted by Ernst & Young) is:

> A transfer pricing method using the costs incurred by the supplied of property (or services) in a controlled transaction. An appropriate cost plus mark-up is added to this cost, to make an appropriate profit in light of the functions performed (**taking into account assets used and risks assumed**) and the market conditions. What is arrived at after adding the cost-plus mark-up to the above costs may be regarded as an arm's length price of the original controlled transaction.[163] [emphasis added]

[163] Australian Taxation Office, *Draft taxation Ruling 1995 / D22—Income tax: using arm's length transfer pricing methodologies in international dealings between associated enterprises,* p.4.

Ernst & Young does not appear to have taken into account the assets used by CitiPower's and Powercor's related party contracts and risks assumed, in determining an appropriate mark-up.

As outlined elsewhere in this chapter, standard economic and finance theory is that the primary interests of shareholders (including the shareholders of related parties) is to earn a reasonable return on the capital they inject into the company which is commensurate with their required return.

In the draft decision, the AER stated that if CitiPower or Powercor indentified any assets owned and utilised by their related party contractors in providing services to them that are not already contained within their RABs, then a margin to reflect the return on and return of those assets would be appropriate. Neither CitiPower nor Powercor identified the existence of any such assets in their revised regulatory proposals.

In summary, while the AER questions the direct applicability of the ATO's guidelines on related party transactions in an economic regulatory context, even to the extent these guidelines are relevant, Ernst & Young's analysis does not appear to be in line with the ATO's guidelines as it has not taken into account the assets used by their related party contractors in determining an appropriate profit margin.

6.5.6 Implications for the regulatory asset base roll-forward

In the draft decision, the AER noted that during the current regulatory period the capital expenditure of each of the Victorian DNSPs included profit margins paid to related party contractors. The AER noted that such amounts were excluded from the Victorian DNSPs’ capex allowances by the ESCV for the current regulatory period, on the basis that these arrangements have the potential to allow for a greater than intended proportion of the benefits of any efficiency gains to be retained within the corporate group. This characterisation of margins was reflected in amendments to the ESCV’s Guideline 3, where it required the Victorian DNSPs to report capital and operating expenditure exclusive of profit margins paid to related parties as they were regarded as not reflecting the costs of providing regulated services.[164]

The AER noted the NER required that ‘all capital expenditure incurred’ is to be rolled into a DNSP's RAB. The AER considered the extent to which the margins paid would be characterised as inefficient expenditure or whether they were so excessive as to have no relationship to the services provided by the related party or the DNSP (and therefore not recognisable as capital expenditure under the NER).[165]

The AER considered that:

- the apparent requirement for the AER to automatically roll into the RAB all amounts characterised as capex creates an incentive for DNSPs to enter into related party contracts and seek outcomes contrary to the efficiency objectives of the regulatory framework. For example, a DNSP may present contract charges as actual capital expenditure, yet actual costs of service delivery incurred by the

[164] ESCV, *Final decision—Revisions to guideline no. 3 regulatory accounting information requirements*, December 2006,p. 13.

[165] AER, *Draft decision*, p.189.

related party may be lower due to efficiency gains or because the service provider receives an inflated contract charge. In this situation, where contract charges are rolled into the RAB, these efficiency gains are retained by the ultimate owner or owners of both entities and there is no incentive for gains to be passed back to consumers.

- in the case of opex allowances, incentive carryover mechanisms and the setting of allowances based on underlying costs (not simply contracted rates) ensure that efficiency gains are retained by the DNSP for an appropriate amount of time then passed to end users.

- in the case of capital expenditures, while regulators are able to set allowances that are reflective of efficient costs on an ex ante basis, there are no checks on an ex post basis to ensure the DNSPs are being rewarded or penalised for bona fide efficiency gains or losses. While there is a clear policy intention to not undertake ex post efficiency assessments of capital expenditure, the AER considered that the NER framework needs to address any incentives that a DNSP and its related party may have to capitalise amounts which bear no relationship to actual costs.[166]

In the draft decision the AER concluded that under the NER it was required to recognise the capitalised related party profit margins paid by the Victorian DNSPs in the current regulatory control period as capital expenditure incurred. Consequently the AER was required to roll this expenditure into the DNSPs' RABs without adjustment. The AER considered that the capitalisation of related party margins gives rise to more fundamental issues relating to the RAB roll-forward requirements which would require changes to the NER (including to the equivalent provisions in chapter 6A).[167]

The AER has maintained this approach in this final decision. Further discussion on this matter, including the AER's response to issues raised in submissions on the draft decision is set out in chapter 9.

6.5.7 Implications for the efficiency benefit sharing scheme

6.5.7.1 AER draft decision

An important principle behind the efficiency benefit sharing scheme (EBSS) is that the forecast opex allowance and actual opex incurred must be calculated on a like-for-like basis. To do otherwise would distort the calculation of the incremental efficiency gain (or loss), which at worst may reward the service provider for efficiencies not actually achieved (or penalise them for efficiency losses which did not occur), and at best would distort the sharing ratio of efficiencies between the service provider and consumers intended in the scheme.

Following this consistency principle:

- where the forecast opex is based on the service provider’s actual opex (that is, the contract price) then the ‘actual’ opex used in the EBSS calculation at the end of the regulatory control period should also be based on the contract price, and

[166] AER, *Draft decision*, p.189.
[167] AER, *Draft decision*, p.190.

- where the contract price fails the 'presumption threshold' and does not meet the legitimate economic reasons for the margin and the AER bases the service provider's forecast opex on the related party's actual opex, then for consistency, the related party's actual opex and not the service provider's actual opex (that is, not the contract price) should be used in the EBSS calculation at the end of the regulatory control period.

This approach results in past operating efficiencies realised by related party contractors being rewarded for through the EBSS, making a margin for historical efficiencies in the opex forecast unnecessary.

As outlined elsewhere in this chapter, this approach ensures that the service provider is rewarded for the efficiencies achieved by the related party in the same way it would be rewarded if it had achieved those efficiencies itself (and most importantly, customers' share of efficiencies is the same as if the service provider had achieved those efficiencies rather than the related party). The sharing of the service provider's share of the efficiencies between itself and its related party is then a matter for those parties to decide upon and which the AER would not and should not be involved in. This approach is consistent with that followed by the ESCV.

6.5.7.2 Victorian DNSPs' revised regulatory proposals

JEN stated that it is concerned about the reliance placed on the EBSS by the AER to reward contractors for efficiencies achieved during the regulatory control period. Its reasons for this concern are because:

- the scheme applies only to operating expenditure and not to capital expenditure
- the uncertainty created by changes since the original scheme was introduced by the ESC, coupled with the potential for future exercises of regulatory discretion to affect the EBSS allowances, means that DNSPs can place little reliance on the scheme providing adequate compensation for future efficiencies, and
- it is not clear why the AER intends to apply the EBSS differently to contracts depending on whether they pass or fail the presumption threshold.[168]

6.5.7.3 AER considerations and conclusion

The AER responds to each of JEN's three concerns in turn.

Firstly, the AER's approach is simply to treat efficiencies realised by related party contractors in the same way as all other operating and capital expenditure efficiencies realised by the DNSP itself are treated under the regulatory regime. That is, with the application of the EBSS to opex and not capex, all operating efficiencies are retained for six years while all capital efficiencies are retained until the end of the regulatory control period in which they are realised. If these retention periods are appropriate for efficiencies realised by the DNSP itself, the AER sees no reasons why they would not be equally appropriate for efficiencies realised by related party contractors. This issue is discussed further in section 6.5.3.5.

[168] JEN, *Revised regulatory proposal*, pp.82-83

Secondly, under the NER, the regulatory discretion given to the AER in applying the EBSS at the end of the regulatory control period is significantly more constrained than that applying to regulators in the application of previous similar schemes. Under the NER, the AER must publish a scheme in a separate process prior to application. Further, as a constituent decision the AER must set out in advance (that is, as part of the distribution determination) how the AER will apply the scheme at the end of the regulatory control period to which the determination applies. While the AER has considered JEN's concerns, the NER provides JEN significant regulatory certainty about how the EBSS will be applied at the end of the forthcoming regulatory control period. Therefore, the AER considers JEN's concerns over uncertainty in how the scheme will be applied to be unfounded.

Thirdly, the different treatment between contracts that pass and fail the presumption threshold is that, for contracts that pass the presumption threshold the AER can rely on competitive pressures to pass through efficiencies. Where as for contracts that fail the presumption threshold (that is, for contracts for the parties had an incentive to agree to non-arm's length terms and did not go through a competitive tendering process) the AER can not reasonably rely that the contract arrangements themselves will naturally pass through the benefit of past efficiencies in an appropriate timeframe. Hence, the AER's more intrusive and precise calculation of past efficiencies (through the EBSS) which ensures that DNSPs and their related party contractors only retain the benefit of past efficiencies for six years before these benefits are passed onto consumers.

6.5.8 Implications for the assessment of alternative control services

In the draft decision the AER essentially applied the same outsourcing and related party transactions approach to assessing the Victorian DNSPs' proposed alternative control services prices as the AER applied to the assessment of standard control operating and capital expenditure forecasts.[169]

Part of this framework was the principle that the benefit of historical efficiencies realised by related party contractors should be retained by the DNSPs and their related parties for a period of time, and then passed through to consumers. Consistent with the treatment of other efficiencies under the regulatory regime, operating efficiencies were to be retained for five years in addition to the year they are realised whilst capital efficiencies were to be retained until the end of the regulatory control period.

In relation to standard control services, under the AER's framework in the draft decision, this treatment of operating efficiencies would be achieved through the method used to measure efficiencies under the EBSS (i.e. through the EBSS building block allowance). Accordingly no 'margin' in the opex forecasts was required to achieve this outcome.

In recognition that the AER did not apply an EBSS to alternative control services, in the draft decision the AER allowed a margin (of 3 per cent) in its alternative control services prices to reward DNSPs and their related parties for assumed efficiencies realised in the current regulatory period. The AER stated that this margin would not be continued in the regulatory control period after the forthcoming regulatory control

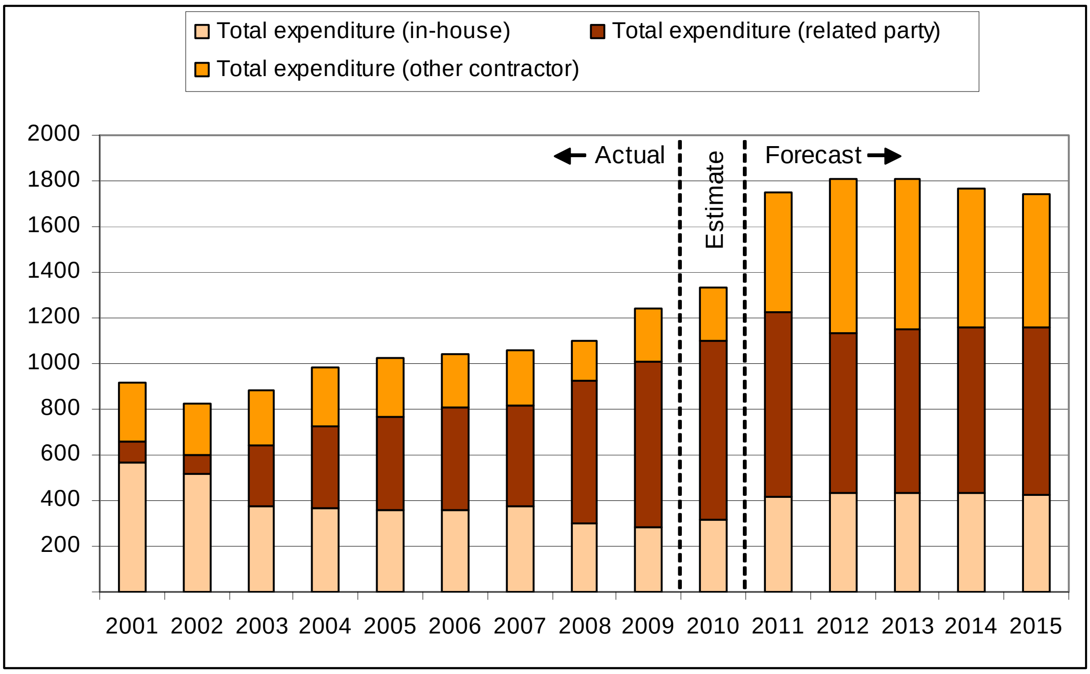
[169] AER, *Draft decision*, p.190.

period unless a DNSP was able to demonstrate that it or its related party has achieved further efficiencies in the forthcoming regulatory control period.[170]

The AER has maintained this approach in this final decision. Further discussion on this matter, including the AER's response to issues raised in submissions on the draft decision is set out in chapter 20.

6.6 Issues and AER considerations—Assessment of individual outsourcing arrangements

Figure 6.4 Victorian DNSP revised proposals—Total expenditure (capital, operating, maintenance) by service delivery model (m, $2010)



Source: Victorian DNSP revised regulatory proposal RIN templates

Figure 6.4 sets out the total actual expenditure (capital, operating and maintenance) of the Victorian DNSPs over the previous and current regulatory control periods, and their forecast total expenditure over the forthcoming regulatory control period. This expenditure is split between expenditure delivered 'in-house' by the Victorian DNSPs themselves, and expenditure delivered by related party contractors and other (non-related party) contractors.

As can be seen from Figure 6.4, from 2001 to 2010 there has been an overall trend away from the in-house provision of services and towards the greater use of outsourcing, and in particular, outsourcing to related party contractors. In 2001, 62.1 per cent of expenditure was delivered in-house while this decreased to 23.6 per cent by 2010. Over that same period, outsourcing to related party contractors has increased from 9.4 per cent of total expenditure to 58.8 per cent, while outsourcing to non-related party contractors has decreased from 28.4 per cent to 17.7 per cent.

[170] AER, *Draft decision*, pp.190-191.

At the overall level, the forthcoming regulatory control period is expected to result in a significant change to this composition. While there is only a small expected increase in the proportion of expenditure delivered through outsourcing, significantly more of the outsourced expenditure is expected to be delivered by non-related party contractors (with a commensurate decrease in the proportion delivered by related party contractors).

This change in composition is primarily driven by United Energy's adoption of a new business model from mid-2011 which sees its service provision by related parties drop from an average of 98.7 per cent of its total expenditure in the current period to 8.6 per cent in the forthcoming period. At the same time its outsourcing to non-related party contractors is forecast to increase from no expenditure in the current period to 75.1 per cent of total expenditure in the forthcoming period. SP AusNet's partial move away from related party to non-related party outsourcing also contributes to the overall fall in the proportion of expenditure forecast to be delivered by related party contractors.

In contrast, CitiPower's, Powercor's and JEN's outsourcing to related party contractors as a proportion of total expenditure is expected to increase in the forthcoming regulatory control period from already high levels in the current regulatory period. While in the current period United Energy has used outsourcing to related party contractors the most, outsourcing to related party contractors will be used the most by JEN in the forthcoming period. JEN forecasts that [c-i-c] per cent of its expenditure will be delivered through related party contractors (up from [c-i-c] per cent in the current period). CitiPower and Powercor forecast that 76.5 per cent and 61.3 per cent, respectively, of their expenditure will be delivered through related parties (up from 73.7 per cent and 45.6 per cent, respectively).

Table 6.2 sets out the average proportion of expenditure for each Victorian DNSP by service delivery model (in-house, related party contractor, other contractor) over the previous, current and forthcoming regulatory control periods.

As noted previously in this chapter, the AER recognises the significant economies of scale, scope and other efficiencies (such as 'know-how') that the Victorian DNSPs have likely been able to gain access to through outsourcing. At the same time, the AER also recognises that prima facie, outsourcing to related party contractors could provide an opportunity for service providers to maintain their reported expenditure at an ‘artificially inflated’ level in order to influence their future expenditure allowances, increase their regulatory asset bases, and retain the benefit of realised historical efficiencies for a prolonged or indefinite period of time rather then sharing the benefit of these efficiencies with consumers through lower prices.

In total, the Victorian DNSPs forecast of capital, operating and maintenance expenditure amounts to $8 876 million over the forthcoming regulatory control period. Of that amount, $3 690 million of expenditure is forecast to be delivered through related party contractors and $3 040m is forecast to be delivered through non-related party contractors.

As set out in section 6.5.1, while in most circumstances it is reasonable to presume that contract charges paid to non-related party contractors are efficient and prudent, this presumption is not reasonable with charges paid to related party contractors, and therefore it is essential these contract charges be more closely scrutinised.

In this section, the AER assesses the major outsourcing arrangements of each of the Victorian DNSPs against the approach set out in section 6.5, which reflects the AER's interpretation of the NEL and NER applied to the specific issue of assessing outsourcing arrangements.

Table 6.2 Victorian DNSPs' revised regulatory proposals—Total expenditure (capital, operating, maintenance) by service delivery model (per cent)

	2001-2005 average	2006-2010 average	2011-2015 average
CitiPower			
In-house	29.7	9.4	8.6
Related party	39.7	73.7	76.5
Other contractor	30.6	16.9	14.9
Powercor			
In-house	58.2	29.5	17.3
Related party	4.3	45.6	61.3
Other contractor	37.5	24.9	21.4
JEN			
In-house	[c-i-c]	[c-i-c]	[c-i-c]
Related party	[c-i-c]	[c-i-c]	[c-i-c]
Other contractor	-	-	-
SP AusNet			
In-house	58.2	57.0	52.1
Related party	0.3	10.4	4.0
Other contractor	41.6	32.5	44.0
United Energy			
In-house	44.9	1.3	16.3
Related party	55.1	98.7	8.6
Other contractor	-	-	75.1
All Victorian DNSPs			
In-house	64.2	35.1	36.8
Related party	35.8	64.9	63.2
Other contractor	26.8	19.4	34.2

Source: Victorian DNSP revised regulatory proposal RIN templates

6.6.2 CitiPower and Powercor

6.6.2.1 Corporate structure and outsourcing arrangements

CitiPower and Powercor are both wholly by CHEDHA Holdings Pty Ltd (CHEDHA Holdings). CHEDHA Holdings is:

- 51 per cent owned by Cheung Kong Infrastructure Holdings Ltd (CKI) and Hong Kong Electric Holdings Ltd (HEH), and
- 49 per cent owned by Spark Infrastructure Group (Spark). Spark is a publicly listed stapled entity on the ASX. [171]

CitiPower's and Powercor's related party transactions comprise:

- corporate services agreements and a discretionary risk management scheme with CHED Services
- network services agreements with Powercor Network Services (PNS)
- a cost sharing arrangement with each other (that is, between CitiPower and Powercor), and
- resources agreements with CHED Services and PNS

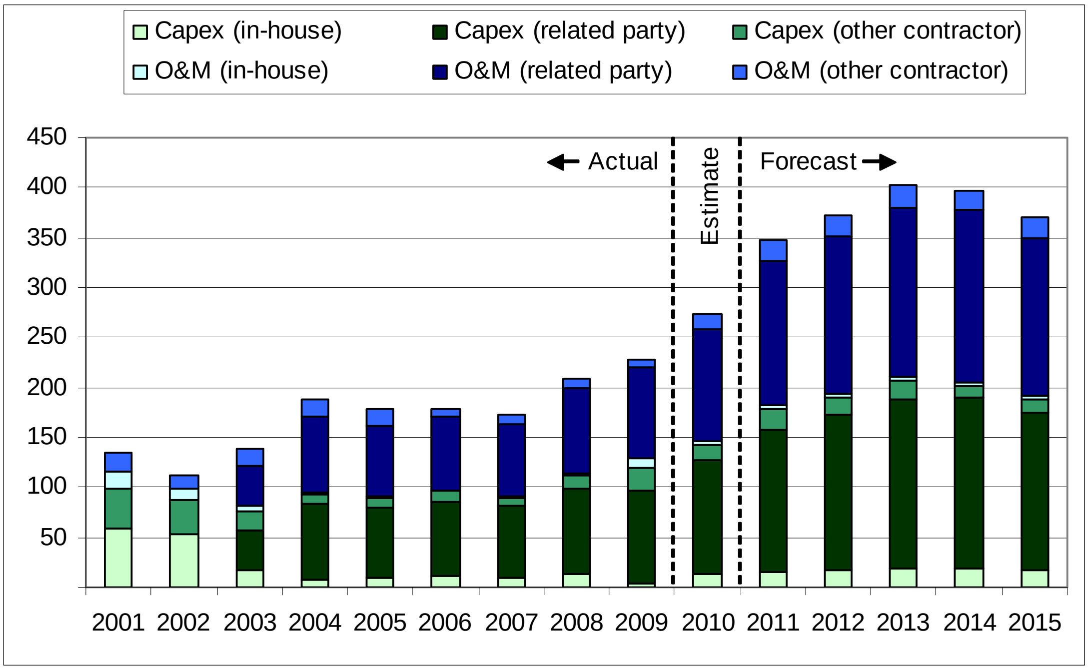
In addition, CitiPower and Powercor have entered into separate electrical network communications agreements and corporate communications agreements with Silk Telecom. At the time these communications agreements were entered into, Silk Telecom was a related party of CitiPower and Powercor (as it was owned by the CKI / HEH group). Subsequently, it has been sold to an unrelated party, Nextgen Networks, a subsidiary of Leighton Holdings.

Each of the above arrangements is assessed in the following sections.

Figure 6.5 and Figure 6.6 set out CitiPower's and Powercor's historical and forecast capital and O&M expenditure by service delivery method (in-house, related party contractor, other contractor). As can be seen from the figures, CitiPower and Powercor forecast that the majority of their expenditure in the forthcoming regulatory control period will be delivered through related party contractors.

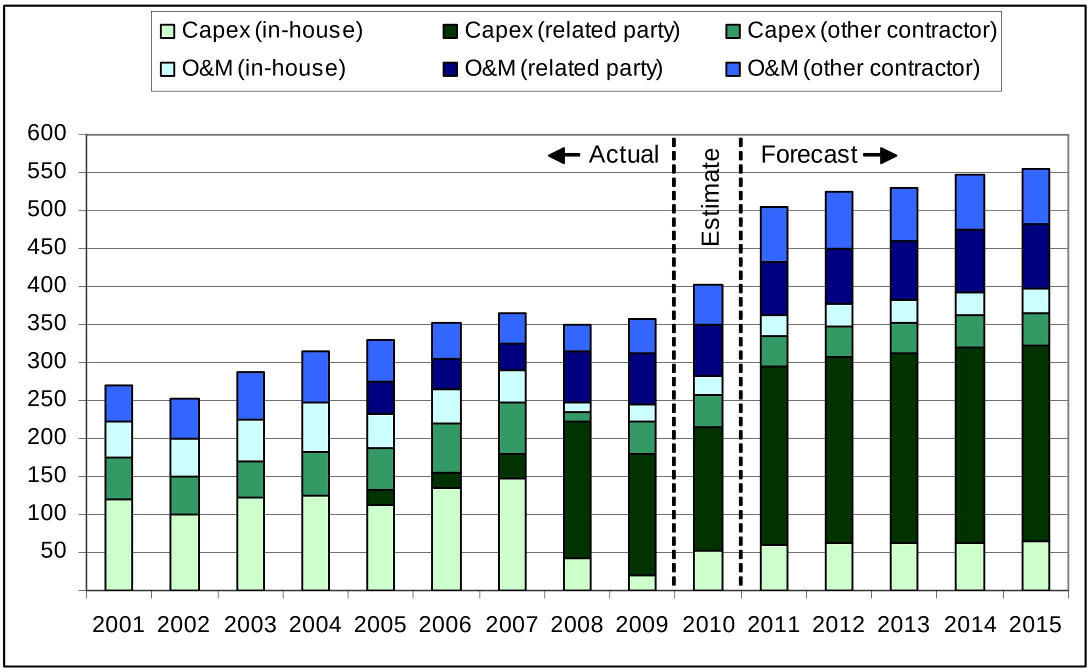
[171] Spark is a stapled security and consists of Spark Infrastructure Holdings No.1 Ltd, Spark Infrastructure Holdings No.2 Ltd, Spark Infrastructure Holdings International Ltd and Spark Infrastructure Trust (SIT). CKI owns 8.73 per cent of Spark and 38.87 per cent of Hong Kong Electric Holdings Ltd.

Figure 6.5 CitiPower revised regulatory proposal—Historical, estimated and forecast capital, operating and maintenance expenditure ($m, $2010)



Source: CitiPower revised regulatory proposal RIN templates.

Figure 6.6 Powercor revised regulatory proposal—Historical, estimated and forecast capital, operating and maintenance expenditure ($m, $2010)



Source: Powercor revised regulatory proposal RIN templates.

As set out in Table 6.3, CitiPower's capex and opex forecasts in its revised regulatory proposal includes $40.2 million and $15.4 million, respectively, of forecast contract margins (in excess of overheads) that CitiPower expects to pay its related party contractors in the forthcoming regulatory control period.

Table 6.3 CitiPower revised regulatory proposal—Forecast contract margins (in excess of overheads) paid to related party contractors ($m, $2010)

	Total 2006-10	2011	2012	2013	2014	2015	Total 2011-15
Capex	24.8	7.2	7.7	8.3	8.9	8.0	**40.2**
O&M	9.5	2.8	3.0	3.1	3.2	3.3	**15.4**
Total	**34.3**	**10.1**	**10.7**	**11.4**	**12.1**	**11.4**	**55.6**

Source: Citipower revised regulatory proposal RIN templates.

As set out in Table 6.4, Powercor's capex and opex forecasts in its revised proposal includes $63.0 million and $36.1 million, respectively, of forecast contract margins (in excess of overheads) that Powercor expects to pay its related party contractors in the forthcoming regulatory control period.

Table 6.4 Powercor revised regulatory proposal—Forecast contract margins (in excess of overheads) paid to related party contractors ($m, $2010)

	Total 2006-10	2011	2012	2013	2014	2015	Total 2011-15
Capex	29.7	11.9	11.9	12.0	13.9	13.3	**63.0**
O&M	26.6	6.6	6.9	7.2	7.5	7.8	**36.1**
Total	**56.4**	**18.5**	**18.9**	**19.3**	**21.4**	**21.1**	**99.2**

Source: Powercor revised regulatory proposal RIN templates.

6.6.2.2 Corporate services agreements with CHED Services and network services agreements with Powercor Network Services

In 2005, a separate legal entity, CHED Services, was created and separated from CitiPower and Powercor to provide corporate services to both DNSPs under separate corporate services agreements (CSAs). The corporate services include CEO, finance, company secretary and legal, HR, corporate affairs, regulation, customer services, IT, and office administration. CHED Services has been providing these services since 1 January 2005, though the current agreements span the period 2008–2010.[172]

In 2008, a separate legal entity, Powercor Network Services (PNS) was created and separated from Powercor to provide construction and maintenance services to CitiPower and Powercor under separate network services agreements (NSAs). These services include customer and connection services, asset replacement, maintenance services, asset performance (fault) services, and network development services. Prior to this time, these services were provided by Powercor to both itself and to CitiPower. The current agreements span the period 2008–2010.

[172] CitiPower, *Initial regulatory proposal*, p.346; Powercor, *Initial regulatory proposal*, p.352.

The pricing of services under the CSAs is based on a fixed charge for 2008, with CPI escalations being applied in 2009 and 2010. The 2008 fixed charge was based on what CitiPower and Powercor claim were forecast efficient costs plus a commercial margin (the margin was based on an Ernst & Young report, discussed below). The pricing of services under the NSAs is based on a mix of fixed quotes, unit rates and labour rates.

In order to facilitate the CSAs and NSAs, CitiPower and Powercor provide staff to CHED Services and PNS under separate resource agreements with CHED Services and PNS.[173]

AER draft decision

Presumption threshold

In the draft decision, the AER considered it could not presume the agreements with CHED Services and PNS reflected efficient and prudent costs, considering:

- given the common ownership between CitiPower, Powercor, CHED Services and PNS, the DNSPs did not have an incentive to enter into arms length arrangements with CHED Services, and
- CitiPower and Powercor did not procure these services on a competitive basis or conduct a tendering process.[174]

Related party margin

In relation to the CSAs, CitiPower and Powercor commissioned Ernst & Young to establish ‘arms length’ margins for corporate services, using methods they say are acceptable to the ATO for related party transfer pricing. Ernst & Young advised different margins for different types of corporate services. These ranged from 3.76 per cent for HR, training and development services to 18.93 per cent for IT services. The margins from Ernst & Young’s report were adopted as the notional margins in the current CSA. However, given the fixed price nature of the contract, the outturn margins earned by CHED Services in any given year could be more or less than these notional margins, depending on CHED Services' actual costs.

Similarly, Ernst & Young advised a margin of 5.26 per cent for construction and maintenance services under the NSA. This margin was adopted as the notional margin in the NSA, though PNS’s outturn margin depends on its actual costs in any given year.

The AER’s draft decision critique of related party transfer pricing methods used for tax purposes being applied to economic regulation is set out in section 6.5.5.3. In summary, the AER did not consider that the Ernst & Young reports demonstrated the efficiency or prudency of the margins in the CSAs or NSAs.

CHED Services’s and PNS's corporate costs had already been factored into CitiPower's and Powercor's base opex and capex forecasts—accordingly the AER considered a margin to compensate for a share of CHED Services’ or PNS's overheads was not appropriate as it would over-recover these costs. Additionally, the AER was not aware of any assets owned and utilised by CHED Services or PNS in

[173] CitiPower, *Initial regulatory proposal*, p.347; Powercor, *Initial regulatory proposal*, p.353.
[174] CitiPower, *Initial regulatory proposal*, p.355; Powercor, *Initial regulatory proposal*, pp.362-363.

providing services to CitiPower and Powercor which are not already contained within the DNSPs' RABs. The AER considered the existence of such assets would justify a margin being paid to CHED Services and / or PNS, but noted this situation did not appear to arise here. Accordingly, following the AER's draft decision approach to assessing outsourcing arrangements set out in section 6.5.3, a case for a margin above CHED Services's or PNS's actual costs had not been established.

The AER also noted that prior to the construction and maintenance services being provided by PNS, these services were provided by Powercor to both itself and CitiPower. Powercor had moved from a business model where it provided these services to itself 'at cost' to one where it now pays a related party 'cost plus margin' for these same or similar services. Powercor listed the 'greater potential for the cost-efficient provision of … back office services' as one of the reasons it moved to its current business model.[175] However, considering Powercor previously had access to significant economies of scale through servicing both itself and CitiPower, the AER was not satisfied that the move to a business model where it now pays a profit margin to a related party (a cost it did not previously incur when providing the same services to itself) reflected the actions of a prudent operator in Powercor's circumstances. The AER noted a similar situation arises with the CHED Services arrangement where services previously provided by CitiPower and Powercor to themselves 'at cost' were not being provided by a related party at 'cost plus margin'.

Further, it appeared that most, if not all staff utilised by CHED Services and PNS are in fact still directly employed by CitiPower or Powercor. CitiPower and Powercor submitted a report from KPMG that described the agreements as follows:

> The Agreements are structured so that Powercor and CitiPower back office employees are effectively "seconded" to CHED and Powercor NS to undertake their daily activities. CHED and Powercor NS then pay Powercor and CitiPower for the use of these resources through a service fee.[176]

The AER noted that CitiPower and Powercor offer the services of their employees to CHED Services 'at cost', but when CHED Services and PNS utilise these same employees to provide services back to CitiPower and Powercor, the DNSPs pay 'cost plus margin'. It appeared to the AER that the profit margins CitiPower and Powercor pay to CHED Services and PNS could be avoided by the DNSPs using their own employees to provide these services to themselves rather than entering into the arrangements they have with CHED Services and PNS. The AER considered it was difficult to see how a prudent operator would second its staff to another business, only to effectively pay their own employees' salaries plus a profit margin to that other business.

Given the above considerations, the AER was not satisfied that the profit margins paid to CHED Services and PNS reflect efficient costs or the costs of a prudent operator in the circumstances of CitiPower and Powercor. In the AER's opinion, it was unlikely that such arrangements would be entered into by parties acting on an arms length basis.

[175] Powercor, *Initial regulatory proposal*, p.365.

[176] KPMG, *Powercor Australia Limited—Consideration of the arms length nature of shared service arrangements*, December 2007, p.2.

While the AER acknowledged the scale economies available through pooling these employees, it appeared a more efficient arrangement would be similar to the cost sharing arrangement between CitiPower and Powercor, discussed in section 6.6.2.4. Under this arrangement CitiPower and Powercor have merged their asset management teams, which operate as a single team, and with the actual costs of these employees allocated between CitiPower and Powercor. The AER noted this setup accesses the scale economies of operating more than one network, while avoiding the payment of a profit margin to a related party.

CitiPower and Powercor revised regulatory proposals

CitiPower and Powercor maintained that the decision to adopt their current service model was prudent at the time of that decision and remained prudent if assessed with the benefit of hindsight, because:

- a key rationale for the decision was to enable CitiPower and Powercor to better focus on their long term asset ownership and performance. CitiPower and Powercor also listed other benefits and referenced a number of board papers and related material from the time the decision to adopt their business model was made, and
- as intended, the current service model has facilitated the provision of services to other entities within their corporate group (notably ETSA Utilities), and enabled their corporate group to expand its business activities to provide services to third parties outside their corporate group, with both resulting in the realisation of additional scale and scope efficiencies not available under the previous service model.

In any event, CitiPower and Powercor argued that the AER is required when assessing the efficiency and prudency of their outsourcing arrangements to:

- adopt a standalone network cost counterfactual, and
- disregard any scale, scope and other efficiencies accruing by reason of the common ownership and operation of the CitiPower and Powercor distribution networks. They argued this would be the case even under their previous business model where Powercor provided services to both itself and CitiPower.

Even if the AER were to take into account the economies of scale and scope from operating multiple networks, CitiPower and Powercor argued that the AER cannot take into account efficiencies accruing to a contractor from the provision of services to third parties.

CitiPower and Powercor accepted that the contract charges paid to CHED Services and PNS cannot be presumed to be efficient and prudent. However, CitiPower stated:

> In short, CitiPower does not agree that it is sufficient for the AER to simply presume that because CitiPower may have had an incentive to agree to non arm's length terms that the Agreements it entered into were actually non arm's length.

Rather, CitiPower and Powercor argued that applying their modified 'stage 2B' assessment framework leads to the conclusion that the contract charges are efficient and prudent. As noted above, their framework consisted of assessing whether the contract price exceeds the costs that would have been incurred if the services were provided in-house on a standalone basis. To support this conclusion, CitiPower and Powercor stated their revised proposals contain:

- evidence that demonstrates that the price payable under the CSAs and NSAs are lower than the cost of in-house provision
- the results of an assessment of the non-price terms and conditions
- the results of an assessment of incentives provided under the CSAs and NSAs, and
- comparative benchmark analysis.

The evidence presented by CitiPower and Powercor that their contract charges are lower than in-house costs:

- is a conceptual argument that because CHED Services and PNS provide services to multiple parties both within and outside their corporate group, it would be expected that their costs would be less than in-house costs. Therefore, CitiPower's and Powercor's current service provision model can be expected to constitute a more efficient outcome than if the services were provided in-house on a standalone basis, and
- a report from KPMG comparing CitiPower’s 2008 actual costs against KPMG’s estimate of the ‘in house, standalone’ cost of running CitiPower’s network, and a separate report containing the same analysis in respect of Powercor
- reports from KPMG (each focusing on different related party arrangements) comparing the terms of the contracts against governance principles for transactions with related parties set down by the CitiPower and Powercor boards.

CitiPower and Powercor included an analysis of the non-price terms of the CSAs and NSAs, and also noted that KPMG assessed the non-price terms. CitiPower and Powercor argued that the non-price terms are comparable to those found in arm's length contracts and stated this should provide the AER with some additional comfort that the agreements were not entered into for the purposes of transfer pricing, or to otherwise agree to non-arm's length terms.

On the incentives provided by the CSAs and NSAs, CitiPower and Powercor argued:

- as both contracts are largely fixed price contracts (with elements of the NSA contract price even decreasing over time) CHED Services and PNS will have an incentive to pursue efficiencies as they will retain the benefit of any cost savings, and
- although not stated in either agreement, the actual costs of CHED Services and PNS have in the past formed the basis for determining the price to be paid in a subsequent term and this approach will continue going forward.

CitiPower and Powercor referred to benchmarking they commissioned from NERA that demonstrates the efficiency of their opex forecasts, inclusive of any margins paid to CHED Services and PNS. CitiPower and Powercor also referred to a survey of market prices by SKM for various capital items which showed that their capital costs were more than SKM's surveyed prices. However, CitiPower argued no real weight should be placed on this benchmarking in relation to its revised proposal.

CitiPower and Powercor disagreed with the position taken by the AER on the ATO's guidelines on international related party transactions, and argued that such guidelines were just as relevant in an economic regulatory context as it is in a taxation context.[177]

AER considerations and conclusion

On CitiPower's and Powercor's decisions to adopt their current service model, the AER agrees that the centralisation of service provision into specialist entities which then provide services to multiple networks within the corporate group is consistent with prudent and good business practice. The AER's concerns stated in the draft decision were not intended to be read as concerns over the creation of CHED Services and PNS, per se, but rather over the pricing arrangements struck between CitiPower, Powercor and these related party contractors. The reasons listed by CitiPower and Powercor seem to reasonably demonstrate the prudence of their service model (that is, the centralisation of group-wide service provision into specialist business segments or entities), but not the efficiency and prudence of the pricing arrangements between the parties.

Additionally, it seems inconsistent to the AER that:

- on one hand CitiPower and Powercor argue that the additional economies of scale and scope realised by CHED Services and PNS in providing services to other parties both within and outside their corporate group demonstrate the prudence under the NER of their service model

- while on the other hand they argue it are these very efficiencies which must be disregarded under the NER by the AER in establishing efficient and prudent cost standards against which to assess their contract charges.[178]

This also seems inconsistent with CitiPower's and Powercor's acceptance that in a workably competitive market a contractor cannot charge above its full economic costs indefinitely for efficiencies it has realised in the past.

The AER maintains its position (set out in section 6.5.3.5) that the adoption of a 'standalone, in-house' cost standard is not appropriate under the NER. Moreover, in

[177] CitiPower, *Revised regulatory proposal*, p.169; Powercor, *Revised regulatory proposal*, p.158.

[178] CitiPower and Powercor list a range of benefits they claim CitiPower and Powercor receive from CHED Services and PNS providing services to third parties. These include increased buying power, reduced overhead costs and increased utilisation of existing labour and equipment resources which lowers costs. The AER agrees that each of these are likely benefits (specifically, likely economies of scale, scope or other efficiencies) that would result in multi-network service provision. But under CitiPower's and Powercor's proposed framework, these benefits could be retained entirely by CHED Services and PNS, with no benefit to CitiPower or Powercor, and yet such arrangements would still be considered efficient and prudent. CitiPower, *Revised regulatory proposal*, p.167; Powercor, *Revised regulatory proposal*, p.156.

order to promote the likely achievement of the NEO, the benefits of efficiencies, once realised, should be shared with consumers after an appropriate period of time.

CitiPower and Powercor stated that their contract charges are less than standalone cost:

- given the nature of the services provided by CHED Services and PNS one would expect them to access scale efficiencies not achievable by CitiPower or Powercor acting on a standalone basis
- reports they commissioned from KPMG that demonstrate their costs would be higher if the provided the services in-house on a standalone basis
- therefore while an incentive to agree to non-arm's length terms existed, the KPMG reports demonstrate CitiPower and Powercor did not act on this incentive.

The AER notes these are the same KPMG reports submitted by CitiPower and Powercor in their initial regulatory proposals, and so do not constitute new information. Again, the AER reiterates that while it agrees CHED Services and PNS would be expected to realise these scale efficiencies, the AER does not accept that a 'standalone, in-house' cost standard is appropriate under the NER.

On the incentive arrangements in the contracts, the AER notes that CitiPower's and Powercor's argument is based on the contract price being largely fixed in nature. However, the inclusion or exclusion of a margin in the original setting of that fixed price does not alter CHED Services' or PNS' incentives under those agreements. Therefore, CitiPower's and Powercor's comments on the incentive arrangements in the agreements do not demonstrate the efficiency or prudence of the margin.

As stated elsewhere, the AER considers that the initial sharing of the efficiency benefits between CitiPower, Powercor and their related party contractors is a matter entirely for those parties to determine. The AER's concern is that those efficiencies are passed on to consumers in an appropriate time period, which the AER considers to be:

- six years in relation to operating efficiencies, and
- at the end of the regulatory period in relation to capital efficiencies.

CitiPower and Powercor stated that the NERA benchmarking they commissioned assessed the relative efficiency of

- the forecast opex of CitiPower, Powercor and the other Victorian DNSPs (as set out in their initial proposals), and
- the opex allowance approved by the relevant regulator for DNSPs in other jurisdictions in their most recent determination.

In conducting this exercise, NERA conducted a regression analysis and used opex ratios consistent with those used by the AER in the South Australia and Queensland distribution determinations.

The AER notes that NERA does not assess CitiPower's and Powercor's actual costs (and ratios derived from these actual costs) relative to the actual costs of other DNSPs. Rather, NERA benchmarks CitiPower's and Powercor's forecast costs against the expenditure allowances of other DNSPs set by the regulator. It is unclear what the results of this analysis suggest about the efficiency of CitiPower and Powercor. NERA's analysis appears to be more a test of the regulator's decision, rather than a test of the relative efficiency of Australian DNSPs.

Perhaps most importantly, to the extent that CitiPower and Powercor are more efficient relative to other Australian DNSPs, this does not automatically entitle them or their related parties to retain the benefit of these efficiencies indefinitely. As stated elsewhere, the AER considers they should retain the benefit of these operating efficiencies for a period of six years and then pass these benefits on to consumers.

In relation to the capex benchmarking by SKM, the AER notes CitiPower argued that no real weight should be placed on this analysis in respect of its network. In respect of Powercor, the AER notes that the SKM benchmarking was considered by and taken into account by the AER's consultant (Nuttall Consulting) in advising the AER on the Victorian DNSPs' capex forecasts.

The AER responds to CitiPower's and Powercor's position on the ATO related party guidelines in section 6.5.5.3.

6.6.2.3 Discretionary risk management scheme with CHED Services

CHED Services has established a discretionary risk management scheme (DRMS), with CitiPower and Powercor as scheme members. The purpose of the scheme is to provide 'in-fill' insurance cover to CitiPower and Powercor in respect of amounts below the policy deductibles for the following external insurance policies:

- liability insurance
- property insurance, and
- motor vehicle insurance.[179]

The DRMS retains the funding reserves based on payments made by CitiPower and Powercor in order to enable CHED Services to meet the cost of claims under the DRMS. CHED Services charges CitiPower and Powercor a fee for the insurance services in accordance with external actuarial assessment and advice. The fee is based on the actual cost of the services plus a margin of 3.2 per cent paid by CitPower and 2.9 per cent for PNS.[180]

AER draft decision

Presumption threshold
In the draft decision, the AER considered it could not reasonably presume that the contract charges under the DRMS reflect efficient costs or costs of a prudent operator in the circumstances of CitiPower and Powercor, as:

[179] CitiPower, *Initial regulatory proposal*, p.346; Powercor, *Initial regulatory proposal*, p.352.
[180] CitiPower, *Initial regulatory proposal*, p.352; Powercor, *Initial regulatory proposal*, p.359.

- given the common ownership of CitiPower, Powercor and CHED Services, the DNSPs did not have an incentive to enter into arms length arrangements with CHED Services, and

- CitiPower and Powercor acknowledged that they did not procure these services on a competitive basis or conduct a tendering process.[181]

Related party margin

In the draft decision, the AER noted:

- CHED Services's corporate costs are already included within CitiPower's and Powercor's expenditure forecasts, and

- the services provided under the DRMS would not appear to utilise any assets not already contained with CitiPower's or Powercor's RAB's.

Accordingly, the AER considered that a case for a margin above CHED Services' actual costs had not been established.

The AER also noted that the set-up of the DRMS did not have an impact on the expected level of deductibles incurred. Rather, its impact appeared to be one of cost-smoothing for CitiPower and Powercor, whereby they pay a relatively constant fee to CHED Services each year, who then incurs the cost of deductibles when they occur, instead of CitiPower and Powercor incurring the deductible costs (which might vary on an annual basis).

When a service provider obtains external insurance, the AER noted the premium price they pay effectively covers the expected cost of the exposure, plus an additional component to cover the insurer's administration costs and a profit margin. Despite having to contribute to the insurer's administration costs and a profit margin, incurring the insurance premium is still often a prudent action giving the cost-smoothing benefits that can be considerable.

However, the AER noted that the risk transfer from CitiPower and Powercor to CHED Services is not significant given the deductibles only relate to relatively low value amounts. It was difficult for the AER to see the prudence in CitiPower's or Powercor's actions in entering this scheme which does not have significant cost-smoothing benefits. If CitiPower and Powercor instead retained these risks, the AER noted their expected costs over the long run would be the same as that paid to CHED Services minus the profit margin. Accordingly, the AER was not satisfied that the profit margin paid to CHED Services was a cost that would be incurred by a prudent operator in CitiPower's or Powercor's circumstances.

CitiPower and Powercor revised regulatory proposals

CitiPower and Powercor stated that:

- due to an oversight, their opex forecasts in their initial proposals did not include the administrative fee payable to CHED Services under the DRMS, and

[181] CitiPower, *Initial regulatory proposal*, p.355; Powercor, *Initial regulatory proposal*, pp.362-363.

- because of this, they do not contest the AER's assessment of the administrative fee.[182]

AER considerations and conclusion

In their revised proposals, CitiPower and Powercor accepted the AER's exclusion of the administrative fee or profit margin paid to CHED Services under the DRMS (noting that due to an oversight, this fee was not included in their initial proposals). Accordingly, the AER has maintained its exclusion of this fee from CitiPower's and Powercor's opex forecasts in this final decision.

6.6.2.4 Cost sharing arrangement between CitiPower and Powercor

In 2007, CitiPower and Powercor merged their asset management teams. The associated costs are shared between CitiPower and Powercor under a cost sharing arrangement.

The agreements entail an annual payment being made between CitiPower and Powercor. The payment is based on the pooling of defined overhead costs and the reallocation of those costs to each DNSP based on defined formula. The difference between the reallocation amount and the actual cost incurred by each DNSP is the amount that is paid by one DNSP to the other.

In the draft decision, the AER considered it could not presume the costs incurred by CitiPower and Powercor under these arrangements reflected efficient and prudent costs, considering:

- given the common ownership of CitiPower and Powercor, the DNSPs did not have an incentive to enter into arms length arrangements with each other, and

- CitiPower and Powercor acknowledged they did not procure these services on a competitive basis or conduct a tendering process.[183]

As described above, the actual costs incurred by CitiPower and Powercor are shared between the DNSPs with no profit margin added. Accordingly, in the draft decision the AER concluded that no issues arose regarding margins in excess of overheads that required analysis.

CitiPower's and Powercor's revised proposals did not comment specifically on these arrangements or the AER's assessment. No additional information has been presented suggesting to the AER that its draft decision assessment is no longer appropriate. Accordingly, the AER has maintained its draft decision position in relation to these arrangements.

6.6.2.5 Resource agreements with CHED Services and PNS.

As noted above, CitiPower and Powercor provide services to CHED Services and PNS under separate resources agreements.

CHED Services and PNS pay CitiPower and Powercor wages and salaries (including bonuses, allowances, leave payments, fringe benefits, fringe benefits tax, payroll tax,

[182] CitiPower, *Revised regulatory proposal*, p.169; Powercor, *Revised regulatory proposal*, p.158.
[183] CitiPower, *Initial regulatory proposal*, p.355; Powercor, *Initial regulatory proposal*, pp.362-363.

superannuation payments and workcover payments), operating expenses incurred by CitiPower or Powercor that are incidental to the provision of the staffing services (including phone calls, stationary, etc), and motor vehicles expenses relating to the services.[184]

These agreements differ from the other agreements between the parties in that it is CitiPower and Powercor providing services to CHED Services and PNS, not the other way around. And in return for these staffing services, CHED Services and PNS pay CitiPower and Powercor 'at cost' for the costs incurred.

As the costs of these resource agreements do not feed directly into CitiPower's and Powercor's expenditure forecasts, they do not need to be analysed in the same manner as the other arrangements. However, AER comments on the interaction between these resource agreements and the corporate and network services agreements, in section 6.6.2.2 which analyses the CSAs and NSAs.

6.6.2.6 Electrical network communications agreement and corporate communications agreement with Silk Telecom

CitiPower and Powercor use Silk Telecom as their principal provider for all telecommunications links and services. Under the electricity network communications agreements, Silk Telecom provides electrical services including SCADA and trunked mobile radio services, and under the corporate communications agreements, it provides corporate communications services including managed wide area network (WAN), WAN links, mobile phones, remote access, PABX, voice and data communications.[185]

Silk Telecom was formed in 2005 from the merger of Powercor Telecom and ETSA Utilities' telecommunications division. At the time it was created, Silk Telecom was ultimately owned by the Cheung Kong group (the same as CitiPower and Powercor), however sat outside CHEDHA holdings (CitiPower's and Powercor's more immediate holding company). In mid-2008, Silk Telecom was sold to Nextgen Networks, a subsidiary of Leighton Holdings.

AER draft decision

Presumption threshold

While there is no longer any common ownership between Silk Telecom and CitiPower and Powercor, the AER noted there was at the time the contracts were entered into, and accordingly CitiPower and Powercor would not have had an incentive to enter into arm's length arrangements with Silk Telecom when the current contracts were negotiated. Further, the DNSPs acknowledged that the current contracts were not procured on a competitive basis or through a tendering process.[186]

In its initial proposal, CitiPower stated that the agreements:

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[184] CitiPower, *Initial regulatory proposal*, p.352; Powercor, *Initial regulatory proposal*, p.359.
[185] CitiPower, *Initial regulatory proposal*, p.346; Powercor, *Initial regulatory proposal*, p.353.
[186] CitiPower, *Initial regulatory proposal*, p.356; Powercor, *Initial regulatory proposal*, p.364.

> …expire in 2010, at which time CitiPower is committed to a competitive tendering process for the future procurement of the services currently provided by Silk Telecom.[187]

Powercor made the same statement in its initial proposal.[188] The AER noted that while the DNSPs may be committed to a competitive tendering process at the end of the current contract period (which cover the period 2006–10) it is the charges under the current contracts which form the basis of CitiPower's and Powercor's expenditure forecasts. Accordingly, the DNSPs' commitment to a tendering process in the future does not substantiate the efficiency or prudence of their forecasts.

CitiPower and Powercor also stated that the current agreements provide that:

> …if a party forms the view that any component of the standard service charge no longer reflects current market prices, it may give notice to the other party to engage in good faith discussions to amend the agreement.[189]

The AER reviewed the 'good faith' re-negotiation provisions in the agreements and made the following points:

- while the electricity network communications agreements allow for any component of the standard services charges to be re-negotiated, the corporate communications agreements only permit re-negotiation for a sub-set of services. This was contrary to CitiPower's and Powercor's statements that 'any' component of the standard services charges may be re-negotiated

- the agreements only permitted a re-negotiation to be commenced prior to 30 September 2008, which the AER understood was a short time after the change of ownership

- in re-negotiating the terms, the contracts require the parties to take into account material (where available) that CitiPower and Powercor stated does not exist[190]

- where the parties are unable to agree to changes, the current standard services charges continue to apply.

Given the above considerations, the AER did not consider that the absence of CitiPower or Powercor initiating contract re-negotiations after Silk Telecom was sold to an unrelated party was sufficient for the AER to presume that the contract charges reflect the efficient costs of a prudent operator.

Related party margin

The AER noted that some of the margins in the contracts appeared to be profit margins while other margins (ranging from 15–25 per cent) appeared to be for

[187] CitiPower, *Initial regulatory proposal*, p.354.

[188] Powercor, *Initial regulatory proposal*, p.361.

[189] CitiPower, *Initial regulatory proposal*, p.354; Powercor, *Initial regulatory proposal*, p.361.

[190] The contracts require the parties to take into account any available market benchmarking reports prepared by independent consultants based on like for like technologies. However, CitiPower and Powercor indicated that there is no direct market evidence or third party benchmarks sufficiently comparable (taking into account the nature and quantity of the services provided by Silk Telecom) to assess the current contract charges against. CitiPower, *Initial regulatory proposal*, p.354; Powercor, *Initial regulatory proposal*, p.361.

corporate overheads (referred to variously as contract management, customer service, technical support and / or administrative support). While the AER considered an allowance for corporate costs was a legitimate economic reason for a margin above direct costs, as set out in section 6.5.3.4, where a contract does not pass the presumption threshold, the AER was not satisfied that an unsupported percentage margin above cost (which is not verified against the actual corporate costs of the contractor) is a sufficient substantiation that the quantum of corporate costs proposed reasonably reflect efficient costs that would be incurred by a prudent operator, or a realistic expectation of input costs. Accordingly, the AER did not include a margin for Silk Telecom's corporate costs in the draft decision. However, the AER stated that if CitiPower and Powercor substantiated an appropriate allocation of Silk Telecom's actual corporate costs in their revised proposal then the AER would allow a margin in this final decision that reflected that amount.

Additionally, the AER was not aware of any assets owned and utilised by Silk Telecom in providing services to CitiPower and Powercor which are not already contained within the DNSPs' RABs. The AER noted the existence of such assets would justify a margin being paid to Silk Telecom, but did not appear to apply here.

CitiPower's and Powercor's revised regulatory proposals

CitiPower and Powercor stated that the AER must accept their forecast communication agreements charges, including the margins, in their opex forecasts as:

- the opex criteria properly construed do not permit the AER to reduce their total opex forecasts 'below the efficient costs of achieving the opex objectives', and
- the AER must have regard to benchmark opex. Benchmarking analysis from NERA commissioned by CitiPower and Powercor established that their opex forecasts (including the forecast communications agreements charges, inclusive of margins) are efficient.[191]

CitiPower and Powercor stated that in the time available, they have not been able to obtain from Silk Telecom the information required to determine the extent to which the margins payable by Silk Telecom may be warranted by reason of:

- the recovery of a reasonable allocation of Silk Telecom's common costs
- the existence of assets owned and utilised by Silk Telecom in providing services under the communications agreements, where those assets are not already contained in CitiPower's and / or Powercor's RABs
- the charges paid under the communications agreements being lower than standalone, in-house costs, and / or

[191] CitiPower, *Revised regulatory proposal*, p.170; Powercor, *Revised regulatory proposal*, p.159.

- any scale, scope or other efficiencies accruing by reason of Silk Telecom's provision of services to parties outside the group to which CitiPower and Powercor belong.[192]

CitiPower and Powercor stated that they:

> … will continue to make efforts to obtain this information and will bring any such information obtained, together with the implications thereof, to the AER's attention at the earliest practicable opportunity.[193]

In the interim, they observed that when Silk Telecom was part of their corporate group it had over [c-i-c] in property, plant and equipment and had significant corporate costs embedded in its structure.[194]

CitiPower and Powercor stated they did not exclude the margins paid to Silk Telecom from their expenditure forecasts in their revised proposals.[195]

AER considerations and conclusion

CitiPower and Powercor did not contest the AER's draft decision assessment of their communications agreements with Silk Telecom against the presumption threshold. Accordingly, CitiPower and Powercor appear to accept that the AER cannot reasonably presume the contract charges for these agreements are efficient and prudent, but rather, the contract charges require further scrutiny.

The AER did not accept CitiPower's and Powercor's statements that the AER's assessment of the margins paid to Silk Telecom reduces their opex forecasts to below efficient costs. This statement from CitiPower and Powercor is based on their position that 'standalone, in-house' costs is the appropriate standard under the NER to assess outsourcing arrangements against. The AER addresses this issue in section 6.5.3.5.

The AER responded to the NERA benchmarking in the previous section.

The AER notes that CitiPower and Powercor did not provide the further information to the AER flagged in their proposals.

The AER maintains its position that while the recovery of overheads and a return on and of assets not contained in the DNSPs' RABs are legitimate economic reasons for the inclusion of a margin, these reasons must be demonstrated by the DNSPs and it should not be assumed these reasons are present in every contract. CitiPower and Powercor have not demonstrated these reasons are present in the communications agreements with Silk Telecom.[196]

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192 CitiPower, *Revised regulatory proposal*, p.171; Powercor, *Revised regulatory proposal*, pp.160–161.

193 CitiPower, *Revised regulatory proposal*, p.171; Powercor, *Revised regulatory proposal*, p.161.

194 CitiPower, *Revised regulatory proposal*, p.171; Powercor, *Revised regulatory proposal*, p.161.

195 CitiPower, *Revised regulatory proposal*, p.171; Powercor, *Revised regulatory proposal*, p.161.

196 While CitiPower and Powercor claimed $[c-i-c] million of property, plant and equipment was utilised by Silk Telecom in providing services prior to its divestiture, they did not provide any documentary evidence verifying this amount or establishing that these assets are not already contained within CitiPower's or Powercor's RABs.

As for the further two reasons for a margin in the Silk Telecom contract (relating to the standalone, in-house cost standard, and the existence of further efficiencies derived from providing services to third parties), as explained in section 6.5.3, the AER does not accept that these are legitimate economic reasons for the payment of a margin.

Accordingly, the AER does not accept CitiPower's and Powercor's revised regulatory proposals, and maintains its draft decision position to exclude the margins paid by the DNSPs to Silk Telecom under their communications agreements from their expenditure forecasts.

6.6.2.7 AER conclusion

Under separate corporate services agreements (CSAs) and network services agreements (NSAs), CHED Services and Powercor Network Services (PNS) provide most of the management, construction and maintenance services required to operate CitiPower's and Powercor's networks. Asset management functions are retained in-house, but provided across both networks through a joint Citipower and Powercor management team.

CitiPower, Powercor, CHED Services and PNS are all owned by CHEDA Holdings, which is ultimately owned by the CKI / HEH group and Spark Infrastructure.[197]

Given the common ownership between the parties, CitiPower and Powercor did not have an incentive to enter into arms length arrangements with these related party contractors. Additionally, they did not procure these services on a competitive basis or conduct a tendering process. Accordingly, the AER maintains its draft decision position that it cannot presume that the contract prices of these agreements reflect efficient costs or costs of a prudent operator in the circumstances of CitiPower and Powercor.

A share of CHED Services’s and PNS's corporate costs have already been factored into CitiPower’s and Powercor’s base opex and capex forecasts—accordingly an additional margin to compensate for a share of their overheads is not appropriate as it would over-recover these costs.

Additionally, the AER is not aware of any assets owned and utilised by these related party contractors in providing services to CitiPower or Powercor which are not already contained within the DNSPs’ RABs. The existence of such assets would justify a margin being paid, but does not appear to apply here. Accordingly, following the approach set out in section 6.5.4, a case for a margin above CHED Services’ and PNS's actual costs has not been established.

In summary, the AER is not satisfied that the margins in excess of overheads paid to related party contractors included within CitiPower's and Powercor's capital and operating expenditure forecasts, reasonably reflect efficient costs or costs of prudent operator in CitiPower's or Powercor's circumstances. In substituting CitiPower's and Powercor's expenditure forecasts for an alternative estimate, the AER has removed

[197] CitiPower, *Initial regulatory proposal*, pp.344-345; Powercor, *Initial regulatory proposal*, pp. 350–351.

these margins, which is an outcome the AER is satisfied reasonably reflects efficient and prudent costs. This adjustment is shown in Table 6.5 and Table 6.6.

Table 6.5 AER final decision—CitiPower—Forecast contract margins (in excess of overheads) paid to related party contractors, 2011-15 total (m, $2010)

	Draft decision	Revised proposal	Final decision
Capex	-	40.2	-
O&M	-	15.4	-
Total	**-**	**55.6**	**-**

Source: CitiPower initial regulatory proposal RIN templates, CitiPower revised regulatory proposal RIN templates, AER draft decision, AER analysis

Table 6.6 AER final decision—Powercor—Forecast contract margins (in excess of overheads) paid to related party contractors, 2011-15 total (m, $2010)

	Draft decision	Revised proposal	Final decision
Capex	-	63.0	-
O&M	-	36.1	-
Total	**-**	**99.2**	**-**

Source: Powercor initial regulatory proposal RIN templates, Powercor revised regulatory proposal RIN templates, AER draft decision, AER analysis

6.6.3 Jemena Electricity Networks (Victoria)

6.6.3.1 Corporate structure and outsourcing arrangements

JEN is a wholly owned subsidiary of Jemena Ltd, which is in turn owned (indirectly) by SPI (Australia) Assets Pty Ltd (SPIAA).[198] SPIAA is owned by Singapore Power International Pte Ltd (SPI) and is the holding company for the Jemena group of entities. SPI is a wholly owned subsidiary by Singapore Power Limited.

Figure 6.7 illustrates that since at least 2001 a significant portion of JEN's expenditure has been provided by related party contractors with minimal expenditure incurred in-house by JEN itself.

JEN was formerly owned and operated by AGLE and then by Alinta Ltd (Alinta). In mid-2000 Agility was established by AGLE to provide infrastructure management and services to the networks owned by AGLE (which at that time included the network now known as JEN). In October 2006, AGLE engaged in an 'asset swap' with Alinta (that is, a merger and divesture) from which Alinta emerged from the transaction with AGLE’s infrastructure and asset management businesses (including

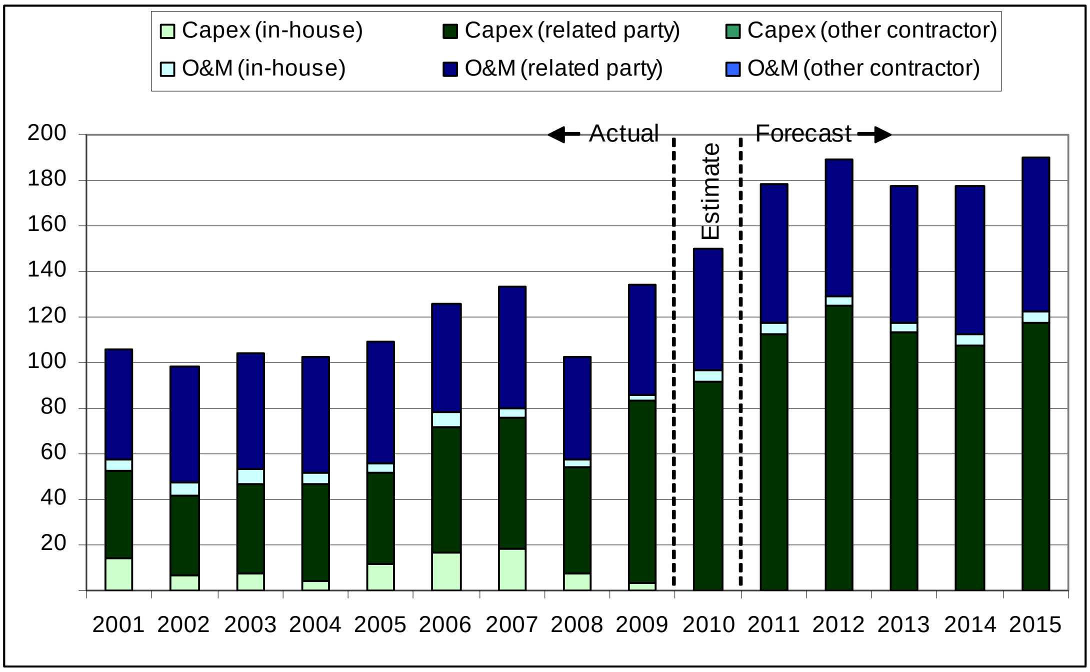
[198] 45.27 per cent of Jemena Ltd is owned directly by SPIAA. The remaining 54.73 per cent is owned by SPIAA indirectly through Jemena Group Holdings Pty Ltd (9.46 per cent) and Jemena Holdings Pty Ltd (45.27 per cent). Jemena Group Holdings and Jemena Holdings are wholly owned subsidiaries of SPIAA.

JEN and Agility). Agility was merged with Alinta's asset management business which was known as Alinta Asset Management.

In August 2007, several Babcock & Brown entities and SPI acquired Alinta and at that time Alinta was delisted from the ASX. SPI emerged as the operator and owner of the eastern Australian assets and operations of Alinta, except for Multinet Group Holdings and Alinta Asset Management (which at that time was 51 per cent owned by Babcock & Brown and 49 per cent owned by SPI). In August 2008, the SPI owned assets became known the Jemena group (which JEN is a part of) and in May 2009, SPI acquired Babcock and Brown's stake in Alinta Asset Management (which it renamed Jemena Asset Management [JAM]).

Figure 6.7 sets out JEN's historical and forecast capital and O&M expenditure by service delivery method (in-house, related party contractor, other contractor). As can be seen from the figure, the vast majority of JEN's expenditure has historically been provided through related party contractors. As is also evident, JEN expects the proportion of its expenditure delivered through related party contractors to increase to close to 100 per cent over the forthcoming regulatory control period.

Figure 6.7 JEN revised regulatory proposal—Historical, estimated and forecast capital, operating and maintenance expenditure (m, $2010)



Source: JEN revised regulatory proposal RIN templates.

[Text removed confidential]

Table 6.7 JEN revised regulatory proposal—Forecast contract margins (in excess of overheads) paid to related party contractors (m, $2010)

	Total 2006-10	2011	2012	2013	2014	2015	Total 2011-15
Capex	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	**[c-i-c]**
O&M	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	**[c-i-c]**
Total	**[c-i-c]**	**[c-i-c]**	**[c-i-c]**	**[c-i-c]**	**[c-i-c]**	**[c-i-c]**	**[c-i-c]**

Source: JEN revised regulatory proposal RIN templates.

6.6.3.2 Letter agreement / Asset management agreement with Jemena Asset Management

JAM (formerly Agility) has been managing JEN's (formerly AGLE's) network since October 2000, under a 'letter agreement'.[199] The letter agreement appoints JAM as agent of JEN, and pursuant to the agreement, JAM provides networks operations, capital works, metering and billing, IT, asset management and service integration services to JEN.[200]

[Text removed confidential

[199] Jemena, *Initial regulatory proposal—Appendix 17.1*, p.5.
[200] Jemena, *Initial regulatory proposal—Appendix 17.1*, p.2.

Essentially, JEN's forecast opex and capex appears to be derived from the combination of JAM's current actual costs under the letter arrangement projected forwards with the margin from the AMA added on top.

AER draft decision

Presumption threshold

The letter agreement was established in 2000 under the former AGL ownership.[201] Given the common ownership between AGLE and Agility, the AER considered an incentive existed to enter into arrangements that were not on arm's length terms. The AER noted the ESCV formed the same conclusion on this arrangement in the 2006 EDPR.[202]

With the change of ownership, AGLE (now JEN) and Agility (now JAM), maintained the letter agreement. It was unclear to the AER whether the letter agreement allowed for a re-negotiation of terms, however the AER noted that even if this was the case, given the common ownership of JEN and JAM, an incentive for JEN to enter into arrangements that were not arm's length would have existed. Further, this incentive also applied during the AMA negotiation. JEN acknowledged that the AMA was not procured on a genuinely competitive basis.[203] Accordingly, the AER considered that it cannot presume that the contract prices under the AMA reflect efficient costs or costs of a prudent operator in the circumstances of JEN.

The AER noted JEN's statement that it 'employed the same internal controls for the AMA negotiations that Jemena would apply to external competitive tenders'. These included:

- a formal request for proposal issued by JEN to JAM
- a formal response from JAM following a documented question-and-answer process

[201] Jemena, *Initial regulatory proposal—Appendix 17.1*, p.15.
[202] ESCV, *EDPR 2006-10—Final decision volume 1—Statement of purpose and reasons*, October 2005, p.178.
[203] Jemena, *Initial regulatory proposal—Appendix 17.1*, p.5.

- structured commercial negotiations, with probity controls and documented audit trails, and
- an asset owner steering committee to govern negotiation strategy and to internally endorse and recommend the scope of the AMA services, pricing, incentive arrangements and terms and conditions.[204]

The AER acknowledged these positive aspects of the process taken by JEN during the AMA negotiation process. However, the AER did not consider these were sufficient to ‘presume’ the contract terms reflect arms length terms. Given the incentive for JEN to agree to non-arms length terms with JAM, the AER considered that only the discipline of a competitive tendering process in a competitive market was sufficient to provide the AER with the assurance that the contract reflects arms length terms without further scrutiny.

Related party margin
The AER noted a share of Jemena Ltd's and JAM’s corporate costs have already been factored into the base opex and capex forecasts—accordingly an additional margin to compensate for a share of Jemena Ltd's or JAM's overheads was not appropriate as it would over-recover these costs. Furthermore, the AER had identified some issues with the corporate costs allocated to JEN which it considered elsewhere in the draft decision.

Additionally, the AER stated it was not aware of any assets owned and utilised by JAM in providing services to JEN which are not already contained within JEN’s RAB. The existence of such assets would justify a margin being paid to JAM, but did not appear to apply here. Accordingly, following the AER’s approach, a case for a margin above JAM’s actual costs had not been established.

The AER noted that under the whole of business cost allocation (WOBCA) methodology depreciation costs associated with IT assets are being allocated by JAM to JEN. The AER noted these assets may be related to assets not already contained in JEN's RAB. If this is the case then a margin reflecting the return on and return of these IT assets would be appropriate. The IT depreciation would be the return of assets. The AER noted these IT depreciation costs were reflected within JEN's proposed base opex, and consequently reflected in JENs forecast opex.

At that stage the AER did not include a margin to reflect the return on these assets as it was not clear whether or not these assets are contained in JEN's RAB or not. However, if JEN was able to demonstrate in its revised proposal that these IT assets are not already included in the RAB, the AER stated it would, in its final decision, allow a margin to reflect the return on these assets.[205] However, if JEN was not able to demonstrate that these assets are not already in its RAB, the AER stated, in its final decision, it would not accept these IT depreciation costs in the base opex forecasts under the assumption that these assets are already contained within JEN's RAB.

[204] Jemena, *Initial regulatory proposal—Appendix 17.1*, p.20.
[205] The AER notes that if Jemena is able to demonstrate that these IT assets are not already in its RAB, an alternative form of compensation may be for these assets to be reported as capex and accordingly rolled into Jemena's RAB.

[Text removed - confidential]

The AER noted that Evans & Peck considered it reasonable to assume that project margins similar to those from the alliance agreements it has been involved with would be applicable to JEN's AMA with JAM. Though Evans & Peck provided the following qualification to its conclusion:

> This also assumes that the Manager under the AMA needs to generate a similar profit and recover similar overheads to other private sector construction and consulting service providers.[206]

The AER stated it was not confident that this assumption holds in relation to the AMA. The AER noted its expectation that in order for an unrelated contractor to compete for services; it would first need to invest in certain capital assets (for example, depots, vehicles, equipment). Assuming these costs are not directly costed in its tenders, the unrelated contractor would need to earn a return of and return on these assets in the contracts it bids for through the margin it includes in the tender. However, in the case of JAM, the AER noted that many if not all of these sorts of assets may already have been contained within JEN's RAB. JAM would therefore not need to earn a profit to recover the return on these assets as its shareholders would already be receiving this return through the inclusion of these assets in JEN's RAB (given that JEN and JAM have the same owners). However, if in its revised proposal,

[206] Jemena, *Initial regulatory proposal—Appendix 7.12*, 'Evans & Peck, *Jemena Electricity Networks (Vic) Limited—Asset management agreement margin*, 25 November 2009', p.10.

JEN is able to establish that JAM provides services to JEN utilising assets not already in JEN's RAB, the AER stated then a margin reflecting the return on and return of these assets would be appropriate.

[Text removed - confidential]

Considering the AER's understanding that most if not all assets utilised by JAM in servicing the AMA are already included within JEN's RAB, that historical efficiencies realised by JAM will be rewarded through the ECM, and the apparent significant understatement of overheads in Evans & Peck's analysis due to misreporting by JEN, the Evans & Peck report did not satisfy the AER that the margin in the AMA reasonably reflected efficient costs or the costs incurred by a prudent operator in the circumstances of JEN.

JEN also submitted an EBIT margin benchmarking report from NERA which revised a previous NERA EBIT margin benchmarking report in response to criticisms from ACG on that previous report.[207] NERA estimated that the average EBIT margin from a sample of companies over the period 2002–06 was 5.5 per cent, with a 95 confidence interval of 4.3–6.7 per cent.[208]

The AER considered that whether or not a margin should be allowed, and the magnitude of that margin if allowed, should not simply be a matter of comparing the margin earned by a related party against industry benchmarks. Rather, the AER considered this was a case-by-case issue and includes consideration of the issues such as whether or not a related party's corporate overheads are already included in the

207 The NERA report was commissioned by Envestra in the context of the last Victorian GAAR.

208 Jemena, *Initial regulatory proposal—Appendix 7.13 'NERA, Allen Consulting Group's review of NERA's benchmarking of contractors' margins critique, October 2007'*, 30 November 2007, p.iv.

reported expenditure and whether it is utilising assets already in the service provider's RAB—both considerations have an impact on the appropriate margin for a specific contract.

[Text removed - confidential]

JEN's consultant (Evans & Peck) identified the AMA as an alliance style contract. Evans & Peck stated:

> …the alliance method of delivery for capital projects and maintenance services is extensively used in the power sector.[209]

Accordingly, the type of contract that the AMA is appeared to be commonly used in the industry and not of higher risk than the industry average. In fact, the only unusual feature is in relation to the recovery of corporate overheads. Evans & Peck stated:

> In Evans & Peck's experience, payment of corporate overheads as part of the actual cost for delivering services is unusual in a typical alliance contract.[210]

That was, under the AMA, JAM recovers its actual overheads whereas under a typical industry contract an increase in overheads above that negotiated into the margin would be borne by the contractor.

In contrast, the AER was aware than in the contract United Energy has recently negotiated with preferred tender applicant, a significant cost overrun would result in the contractor not recovering its indirect costs.

The AER concluded in relation to that issue that JEN had not substantiated that JAM bears a higher than industry average level of risk under the AMA.

JEN revised regulatory proposal

JEN's revised proposal described the negotiation process between JEN and JAM and included background material from this time such [Text removed – confidential]

[209] Evans & Peck, *Jemena Electricity Networks (Vic) Limited—Asset management agreement margin*, 25 November 2009, p. 9

[210] Evans & Peck, *Jemena Electricity Networks (Vic) Limited—Asset management agreement margin*, 25 November 2009, p. 7.

JEN's revised proposal also:

- stated the process was subject to a probity review by Pitcher Partners who did not identify any probity issues with the process, and
- described various background details to the AMA such as the services and performance levels provided, the price related provisions, the governance arrangements, the allocation of risks and liabilities between JEN and JAM, and the incentives provided to their management.[211]

Consistent with JEN's proposed approach to the assessment of outsourcing arrangements (discussed in section 6.5.4.2), JEN argued that the AMA contract price should be viewed as consistent with the opex and capex criteria if the price satisfies the test that it is the same or lower than the costs that would otherwise be incurred if JEN were to provide the services in-house on a standalone basis.[212]

JEN considered the costs of in-house provision can be determined by starting with the contractor's direct costs and then making adjustments to reflect:

- an appropriate portion of the contractor's common costs
- the return on and of assets owned by the contractor and employed in the provision of services, and
- an allowance for economies of scale, scope and other efficiencies not otherwise available to the in-house provider.[213]

[Text removed – confidential]

Therefore, JEN stated that consideration only needs to be given to the third factor.[214]

Given the practical difficulties associated with quantifying the value of economies of scale, scope and other synergies unattainable to a standalone in-house service provider, JEN employed its alternative approach to this assessment (also discussion in section 6.5.4.2). This consisted of considering whether:

- JAM's costs (including its directly and indirectly incurred costs and its recovery of overheads) are lower than those that could be achieved by JEN operating on a standalone basis—JEN concluded this was the case as it:
  - assumed that JAM is able to access economies of scale, scope and other synergies not available to a standalone operator, and therefore assumes JAM's

211 JEN, *Revised regulatory proposal—Appendix 6.12 'Application of the outsourcing assessment framework to the JEN-JAM AMA'*, pp.3-13.

212 JEN, *Revised regulatory proposal—Appendix 6.12 'Application of the outsourcing assessment framework to the JEN-JAM AMA'*, p.3.

213 JEN, *Revised regulatory proposal—Appendix 6.12 'Application of the outsourcing assessment framework to the JEN-JAM AMA'*, p.13.

214 JEN, *Revised regulatory proposal—Appendix 6.12 'Application of the outsourcing assessment framework to the JEN-JAM AMA'*, p.13.

costs would be materially lower than that of a standalone operator, given JAM is a specialist provider of asset management services to a wide range of utilities and is the largest provider of services to utilities in Australia, and

  - listed the sources of the efficiencies it expects JAM can access which JEN could not (for example, greater discounts due to bulk purchasing of materials)[215]

- the margin payable under the AMA is comparable to the margins charged by other contractors given the risks to which JAM is exposed and does not exceed the expected benefits of the economies of scale, scope and other efficiencies offered by JAM—JEN considered this was the case as it:

  - [text removed – confidential]

  - listed more recent studies it considered are consistent with the studies considered at the time of the negotiation

  - [text removed – confidential]

  - [text removed – confidential]

  - JEN also responds to some of the issues raised by the AER in the draft decision on the margin studies submitted in JEN's initial proposal.

- the total price payable by JEN under the AMA is efficient and / or consistent with the costs that would be incurred by a prudent DNSP having regard to capex and opex benchmarking done by both UMS and Nuttall consulting

- the non-price terms and conditions are in line with what one would expect to observe in an arm's length contract

- [text removed – confidential]

It is therefore reasonable to infer that the contract price (that is, the contractor's costs plus the margin) is lower than the in-house cost of provision and so is consistent with the opex and capex criteria.

AER considerations and conclusion

The AER notes that while JEN submitted a substantial amount of background material on the negotiation process between it and JAM, this material does, of itself, appear to demonstrate the efficiency or prudence of the AMA contract charges. JEN does not appear to purport the material demonstrates the efficiency or prudence of its AMA charges either.

[Text removed – confidential]

[215] JEN, *Revised regulatory proposal—Appendix 6.12 'Application of the outsourcing assessment framework to the JEN-JAM AMA'*, pp.14-17.

The remainder of JEN's revised proposal on the AMA concerns JEN's attempt to establish that the [c-i-c] in the AMA is not greater than the economies of scale, scope and other efficiencies available to JAM that would not be available to JEN providing these services in-house on a standalone basis.

As set out in section 6.5.4.2, the AER does not consider this assessment framework proposed by JEN is consistent with the NEL and NER. Under the AER's framework, a case for a margin (in excess of the overheads already included in JEN's opex forecast) has not been established.

That said, while not supportive of JEN's assessment framework, the AER provides the following comments on JEN's application of its proposed framework to assessing the efficiency and prudence of its AMA contract charges.

The AER responds to the EBIT margin benchmarking and overall comparative cost benchmarking referenced by JEN in sections 6.5.5.1 and 6.5.5.2, respectively.

[Text removed – confidential]

However, JEN has not responded to the AER's conclusion that the most unusual feature of the AMA appeared to be that under the AMA, JAM recovers its actual overheads whereas under a typical industry contract (according to Evans & Peck's description of industry norms) an increase in overheads above that negotiated into the margin would be borne by the contractor.

The AER notes that while each of the non-price terms in the AMA appears to be a positive inclusion in the AMA, there is no clear link between the inclusion of these features and demonstrating the efficiency and prudency of the margin in the AMA (which is a price related term).

On the risk and benefit sharing mechanism (RBSM) in the AMA, JEN stated:

[Text removed – confidential]

Similarly, JEN also stated:

[Text removed – confidential]

The AER considers JEN has not accurately explained the timeframe under which efficiencies realised by JAM are passed through to JEN and ultimately consumers.

[Text removed – confidential]

Accordingly, based on JEN's own analysis the only legitimate reason left for the inclusion of a margin relates to rewarding JAM for realised efficiencies.

[Text removed – confidential]

The AER notes that JEN acknowledges that:

> It is not possible to directly compare whether the margin payable under the AMA is less than the benefits derived by JEN from the economies of scale, scope and other synergies offered by JAM.[216]

Based on the above comments, even under JEN's proposed framework (which the AER does not concede is appropriate under the NEL and NER) the AER does not consider JEN has demonstrated that the [c-i-c] in the AMA accurately reflects the

[216] JEN, *Revised regulatory proposal—Appendix 6.12 'Application of the outsourcing assessment framework to the JEN-JAM AMA'*, p.27.

economies of scale, scope and other efficiencies realised by JAM that would not be achievable by JEN providing services in-house on a standalone basis.

6.6.3.3 Enterprise support function arrangement with Jemena Ltd

[Text removed - confidential]

AER draft decision

Presumption threshold

In the draft decision, the AER stated it could not reasonably presume that the costs incurred by JEN under these arrangements reflect efficient costs or costs of a prudent operator in the circumstances of JEN, as:

- given the ownership structure between JEN and Jemena Ltd (JEN is a wholly owned subsidiary of Jemena Ltd), JEN did not have an incentive to enter into an arms length arrangement with Jemena Ltd, and
- the services were not procured on a genuinely competitive basis and no tendering process was undertaken.[217]

Related party margin

The AER noted that the ESF costs are overhead costs, and are allocated among the various networks that the Jemena group operates under its WOBCA methodology. The costs are allocated on a cost recovery basis only, with no profit margin to Jemena Ltd added. Accordingly, the AER stated there were no margins in excess of overheads in relation to this arrangement which required closer scrutiny.

However, the AER was not satisfied that four of the enterprise support function (ESF) categories were sufficiently connected to the provision of distribution services, or had been demonstrated by JEN to be efficient and prudent costs. Those categories were the Singapore Power fee, financial strategy, investment analysis and energy investments cost categories. Accordingly, the AER excluded these costs from JEN's opex forecast.

JEN revised regulatory proposal

JEN accepted the AER's exclusion of the Singapore Power fee but argued the three other ESF categories should be included within its opex forecast. JEN's supporting arguments from its revised proposal are set out in section 6.7.

AER considerations and conclusion

In this final decision:

[217] Jemena, *Initial regulatory proposal—Appendix 17.1*, p.7.

- the AER accepts JEN's exclusion of the Singapore Power from its revised proposal opex forecast, and
- does not accept JEN's revised proposal position on the financial strategy, investment analysis and energy investments cost categories. The AER maintains its draft decision position that these costs are not sufficiently connected to the provision of distribution services to be included within JEN's opex forecast.

These issues are considered in further detail in sections 6.7.2 and 6.7.4, respectively.

6.6.3.4 AER conclusion

Under its AMA, JEN receives most of the management, construction and maintenance services required to operate its network from JAM. Additionally, Jemena Ltd provides management and administrative staff to JEN, though there is no formal agreement between the parties.

Given the common ownership between the parties, JEN did not have an incentive to enter into arrangements with JAM and Jemena Ltd that were not at arm’s length. In addition, the AMA and its arrangement with Jemena Ltd were not procured on a genuinely competitive basis. Accordingly, the AER maintains its draft decision position that it cannot presume that the costs incurred by JEN under these arrangements reflect efficient costs or costs of a prudent operator in the circumstances of JEN.

A share of Jemena Ltd's and JAM’s corporate costs have already been factored into the base opex and capex forecasts—accordingly an additional margin to compensate for a share of Jemena Ltd's or JAM's overheads is not appropriate as it would over-recover these costs. The AER has accepted the overheads allocated to JEN from Jemena Ltd to JAM, except for the adjustments set out in section 6.7.

[Text removed – confidential]

As the services provided directly to JEN from Jemena Ltd are provided on a cost recovery basis only no related party profit margin issues arises in relation to this arrangement requiring assessment.

In summary, the AER is not satisfied that the margins in excess of overheads paid to related party contractors included within JEN's capital and operating expenditure forecasts, reasonably reflect efficient costs or costs of prudent operator in JEN's circumstances. In substituting JEN's expenditure forecasts for an alternative estimate, the AER has removed these margins, which is an outcome the AER is satisfied reasonably reflects efficient and prudent costs. This adjustment is shown in table Table 6.8.

Table 6.8 AER final decision—JEN—Forecast contract margins (in excess of overheads) paid to related party contractors, 2011-15 total (m, $2010)

	Draft decision	Revised proposal	Final decision
Capex	-	[c-i-c]	-
O&M	-	[c-i-c]	-
Total	**-**	**[c-i-c]**	**-**

Source: JEN initial proposal RIN templates, JEN revised regulatory proposal RIN templates, AER draft decision, AER analysis.

6.6.4 SP AusNet

6.6.4.1 Corporate structure and outsourcing arrangements[218]

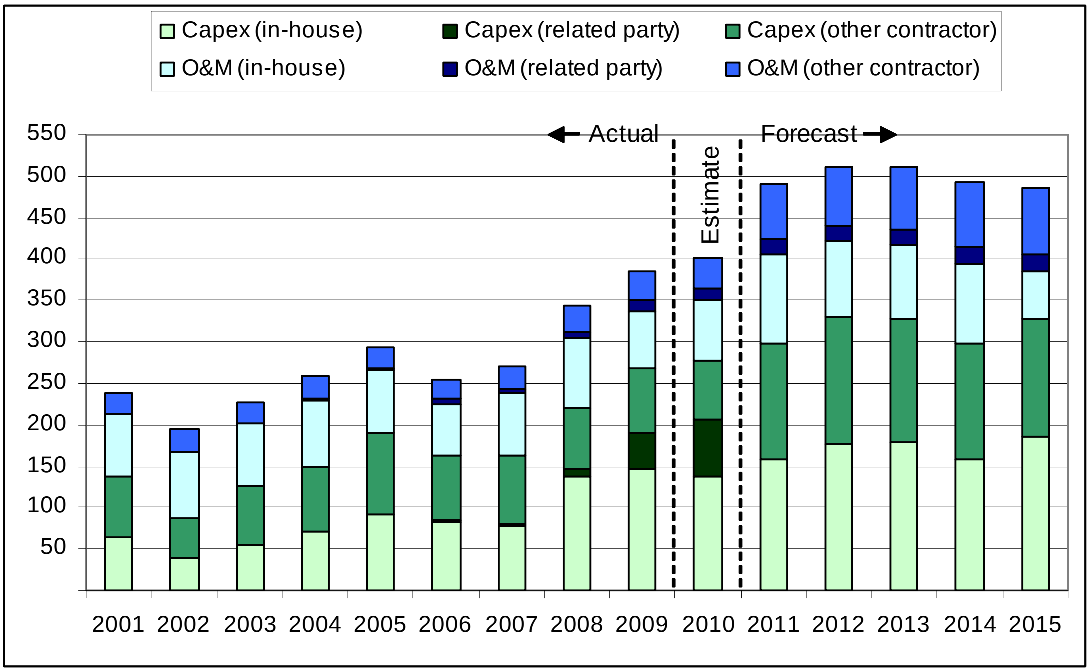
The SP AusNet group comprises three principal entities, namely SP Australia Networks (Distribution) and its subsidiaries, SP Australia Networks (Transmission) and its subsidiaries, and SP Australia Networks (Finance) Trust. SP AusNet is a subsidiary (indirectly) of SP Australia Networks (Distribution).[219]

The SP AusNet group is 51 per cent owned by Singapore Power International and 49 per cent owned by external investors and is listed on the Australian and Singaporean securities exchanges as a stapled security. Singapore Power International is owned directly by Singapore Power, and its ultimate parent is Temasek Holdings (Private) Ltd (Temasek). Temasek is the holding company for various commercial interests of the Singaporean government.[220]

Figure 6.8 sets out SP AusNet's historical and forecast capital and O&M expenditure by service delivery method (in-house, related party contractor, other contractor).

[218] References in this decision to ‘SP AusNet’ are references to ‘SPI Electricity’, and are to be distinguished from references to the ‘SP AusNet group’.
[219] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements),* p.13.
[220] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements),* pp.13–15.

Figure 6.8 SP AusNet revised regulatory proposal—Historical, estimated and forecast capital, operating and maintenance expenditure ($m, $2010)



Source: SP AusNet revised proposal RIN templates

SP AusNet's revised proposal expenditure forecasts did not include any forecast margins (in excess of overheads) that SP AusNet expected to pay its related party contractors in the forthcoming regulatory control period.

Table 6.9 SP AusNet revised proposal—Forecast contract margins (in excess of overheads) paid to related party contractors (m, $2010)

	Total 2006-10	**2011**	**2012**	**2013**	**2014**	**2015**	**Total 2011-15**
Capex	[c-i-c]	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-
Total	**[c-i-c]**	**-**	**-**	**-**	**-**	**-**	**-**

Source: SP AusNet revised regulatory proposal RIN templates

6.6.4.2 Management services agreement with SPI Management Services and IT services arrangement with Enterprise Business Services (Australia)

In October 2005, SPI Management Services (SPIMS) entered into a management services agreement (MSA) with SP Australia Networks (Distribution) and SP Australia Networks (Transmission). The agreement is for an initial period of 10 years but continues for two further 10 year periods unless terminated by either party giving no less than one year’s notice. If SP Australia Networks (Distribution) or SP Australia Networks (Transmission) initiate the termination, SPIMS is entitled to a termination fee equal to the previous year’s management services charge. The initial employees of SPIMS consisted of employees who transferred across from the

SP AusNet group at the time of its restructure prior to the SP AusNet group's initial public offering.[221]

Under the agreement, the management services provided by SPIMS to the SP AusNet group include:

- employee management
- business management
- evaluation of business opportunities
- management of regulatory compliance and relations with regulator
- financial and account management
- management of IT
- management and coordination of maintenance and engineering services
- public and investor relations
- legal and company secretarial services, and
- general administration and company reporting[222]

According to SP AusNet, the management fees charged by SPIMS to the SP AusNet group under the agreement are comprised of:

- a management services charge—which is to compensate SPIMS for the remuneration and other employment costs of SPIMS employees, and
- a performance fee—which is to incentivise SPI Management Services to meet or better the financial and non-financial performance of SP AusNet and to align the interests of SPI Management Services with those of SP AusNet.[223]

In September 2008, the SP AusNet group entered into an IT services agreement with EB Services, a wholly-owned subsidiary of SPI Management Services. The agreement provides that EB Services is the exclusive provider of IT services to the SP AusNet group. The agreement is for an initial term of seven years and may be terminated early by the SP AusNet group in certain circumstances, subject to 12 months notice. A 'transition plan' was in place from the September 2008 until 31 March 2009, at which time the services provided by EB Services were in full operation.[224]

The IT services provided under the agreement include end-user computing, application services, managed services, and project and advisory services. The

[221] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, p.22.
[222] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, p.22.
[223] SPI Electricity, *Electricity distribution price review 2011-2015—Related party arrangements*, November 2009, p.16.
[224] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, pp.25-26.

SP AusNet group has retained the provision of IT strategy and architecture, IT services management, and IT service level contract management.[225]

AER draft decision

Presumption threshold

In the draft decision, the AER considered it could not presume the costs incurred by SP AusNet under these arrangements reflect efficient and prudent costs, considering:

- given the common ownership between the parties, SP AusNet did not have an incentive to enter into an arms length arrangement with SPIMS or EB Services, and
- the services were not procured via a competitive tender.

Related party margin

SP AusNet stated that the management services charge to the SP AusNet group is based on the actual costs of the remuneration of the employees of SPIMS involved in the management of the SP AusNet group, and no margin is included. These costs are then allocated to each of the SP AusNet group's networks via its activity based costing (ABC) allocation methodology. SP AusNet also stated that the performance fee is not allocated to SP AusNet.[226]

As SPIMS provides management services to the SP AusNet group at cost, the AER considered no related party margin issues arose in this situation. However, the AER had some concerns with the ABC allocation methodology used by the SP AusNet group to allocate these costs to SP AusNet and the other networks within the group. The AER's draft decision position on this issue is set out in section 6.7.3.

SP AusNet stated that the IT charges to the SP AusNet group are based on the actual costs of EB Services, and no margin is included. As EB Services provides services to the SP AusNet group at cost, The AER considered no related party margin issues arose in this situation.

SP AusNet revised regulatory proposal

In response to the AER's application of its presumption threshold to its related party transactions, SP AusNet states while each of these related parties are 100 per cent owned by Singapore Power, SP AusNet is only 51 per cent owned by Singapore Power. It states that:

- any decisions affecting the costs incurred by SP AusNet have a material impact on the return to the minority shareholders whose position needs to be considered and carried, and
- as a listed company, SP AusNet has to comply with the ASX Corporate Governance Council's principles of good corporate governance and best practice

225 SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements),* p.26.
226 SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements),* p.23.

recommendations and thus has to comply with strict corporate governance in relation to related party transactions.[227]

Accordingly, SP AusNet states that it:

> … disagrees with the Draft Determination in that from an ownership perspective, there is NO incentive to agree to non-arm's length terms.[228]

AER considerations and conclusion

The AER addresses this issue in section 6.5.1. In summary, the AER maintains its draft decision position that as SPIMS and EB Services are wholly owned by SP AusNet's majority shareholder, the AER cannot presume these contracts are efficient and prudent.

That said, as the services under these contracts are provided at cost, no related party profit margin issues requiring assessment arise in relation to these arrangements.

6.6.4.3 Capital works preferred supplier agreement with SPI (Australia) assets and subsidiaries

SPIAA, JAM and JAM (6) are parties to a capital works preferred supplier agreement with the SP AusNet group [text removed - confidential]

The services that may be awarded to the Jemena group under the agreement include asset replacement capital works, SP AusNet group initiated augmentation works, fire mitigation and automation capital works, and various customer initiated capital works including public lighting.[229]

AER draft decision

Presumption threshold

In the draft decision, the AER considered it could not reasonably presume these contract charges were efficient and prudent as:

- given the common ownership between SP AusNet and the relevant entities in the Jemena group (that is, SPIAA, JAM, JAM(6)), SP AusNet did not have an incentive to enter into an arm’s length arrangement with these entities, and
- SP AusNet acknowledged that there was no tendering process in relation to the procurement of these services.[230]

Related party margin

As the corporate costs of SPIAA, JAM and JAM (6) had already been factored into the base opex and capex forecasts—the AER considered a margin to compensate for a share of the Jemena group’s overheads was not appropriate as it would over-recover these costs. Additionally, the AER was not aware of any assets owned and utilised by these Jemena group entities in providing services to SP AusNet which are not already

[227] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.8-11.
[228] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.9.
[229] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, pp.32-33.
[230] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, p.33.

contained within SP AusNet’s regulatory asset base. The existence of such assets would justify a margin being paid to these Jemena entities, but did not appear to apply here. Accordingly, following the AER’s approach a case for a margin above SPIAA’s, JAM’s and JAM (6)’s actual costs had not been established.

[Text removed - confidential]

[231] SP AusNet itself had explicitly removed the opex profit margin from the calculation of its efficient base year opex, and it stated that the removal of this related party profit margin from its base year opex clearly demonstrated its opex forecast met the prudency requirement in the NER.[232] In contrast, SP AusNet had not removed the same profit margin from its capex forecast. The AER noted that the same prudency requirements in the NER apply to the opex and capex forecasts.

In explaining why this profit margin had not been removed from the capex forecast, SP AusNet stated:

> SP AusNet is also of the opinion that the AER's definition of the related party does not have an "incurred cost" for each line of its charge then this should be treated as a profit margin is flawed. All companies whether regulated or unregulated would incur depreciation and cost of capital costs which would not always be revealed just by looking at the make-up of the charges and the statutory accounts. In SP AusNet's opinion related parties should be allowed a return of and return on capital invested just as non related parties include an allowance for these costs in determining their profit margin.[233]

The AER agreed with SP AusNet in that it also considered that the owners of a related party should have a reasonable opportunity to earn a return on and return of the capital the owners inject into the business. However, the AER contented that if these assets used by the related party to provide services to the DNSP are already contained within the DNSP's RAB, then the owners of the related party (who are the same owners as the DNSP) will already be receiving a return of and return on these assets. Unlike SP AusNet, the AER did not assume that assets used by the related party but not in the DNSP's RAB exist in all circumstances. Rather, the AER considered that it is up to the DNSP to demonstrate that there are assets utilised by its related party not in its RAB, and consequently assets where the owners of the related party are not receiving a return on and return of these assets.

SP AusNet revised regulatory proposal

SP AusNet's revised regulatory proposal contained the same arguments on the presumption threshold as discussion in relation to the SPIMS arrangement in the previous section.

That said, SP AusNet's revised proposal did not include the related party profit margin in its capex forecast that was included in its initial proposal.

[231] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, p.35.
[232] SP AusNet, *Initial regulatory proposal*, pp.206-207.
[233] SP AusNet, *RIN templates—Related party margins—22 March 2010*, 23 March 2010, p.4.

AER considerations and conclusion

The AER maintains its draft decision position that given the common ownership between the parties and the lack of a competitive tender, it cannot presume the contract with SPIAA is efficient and prudent. However, as SP AusNet has removed the related party profit margin from its capex forecast, no related party profit margin issues arise that require assessment.

6.6.4.4 Electricity distribution central region agreement with Tenix Alliance

SP AusNet, Tenix and Tenix Alliance were previously parties to a network services alliance agreement (NSAA), commonly referred to as the 't^2 Alliance'. The t^2 Alliance was contracted to perform most of the minor capital, operations and maintenance work on the SP AusNet group's electricity and gas distribution networks.[234]

The NSAA was executed in 2003 for a period of five years with two five year extensions. The NSAA provided the SP AusNet group with the option to terminate the t2 Alliance on 31 March 2008 provided notice was given by 31 March [text removed - confidential].[235]

In September 2006, the SP AusNet group and Tenix agreed to terminate the NSAA effective 1 April 2008. [text removed - confidential].[236]

The SP AusNet group has established an installation service providers' (ISP's) panel. Tenix Alliance was appointed to the panel in August 2007, meaning that it can bid for projects on a competitive basis together with other contractors on the panel.

After being appointed to the panel, SP AusNet awarded Tenix Alliance its electricity distribution central region agreement. The services provided by Tenix Alliance under

[234] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, p.37.
[235][Text removed - confidential].
[236] SP AusNet, *Initial regulatory proposal—Appendix (related party arrangements)*, p.38.

the agreement include electricity distribution operations and maintenance, asset replacement, and capital works.

AER draft decision

Presumption threshold

In the draft decision, [Text removed - confidential].

Noting this possible limitation on the competitiveness of the electricity distribution central region agreement tender process, the AER considered that the agreement may still reasonably pass the presumption threshold, and therefore the AER may still be able to reasonably presume the contract price under the agreement reflects efficient and prudent costs as:

- there is no common ownership between SP AusNet and Tenix Alliance that would incentivise SP AusNet to enter into a non-arm's length agreement with Tenix Alliance, and

- the AER was not aware of any side-payments or other transactions between the parties that would lead SP AusNet to accept a contract from Tenix Alliance on non-arm's length terms.

Accordingly, the AER did not made any adjustments to the expenditure forecasts in respect of the margin in this agreement.

SP AusNet revised regulatory proposal

SP AusNet stated that as there is no common ownership between Tenix Alliance and SP AusNet, there is no incentive to agree to non-arm's length terms. Further, SP AusNet confirmed that there are no side-payments or other transactions between the parties that would lead SP AusNet to agree to non-arm's length terms with Tenix Alliance.[237]

SP AusNet also stated:

> [Text removed - confidential].[238]

AER considerations and conclusion

Given the lack of common ownership, side-payments or other transactions between SP AusNet and Tenix Alliance, the AER re-affirms its draft decision position and accepts SP AusNet revised proposal. That is, the AER considers it is reasonable to

[237] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.10.
[238] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.11.

presume the contract price SP AusNet pays Tenix Alliance (including margin) reasonably reflects efficient and prudent costs.

Further, given SP AusNet's statement that [Text removed - confidential] the AER accepts these contract charges as efficient [text removed - confidential].

6.6.4.5 AER conclusion

SP AusNet has arrangements with its related parties SPIMS, EB Services and SPIAA. It also has a major outsourcing arrangement with an unrelated party, Tenix Alliance.

Given the common ownership between SP AusNet, SPIMS, EB Services and SPIAA, SP AusNet had an incentive to enter into arrangements with these parties that were not at arm’s length. In addition, these arrangements were not procured on a genuinely competitive basis. Accordingly, the AER maintains its draft decision position that it cannot presume that the costs incurred by SP AusNet under these arrangements reflect efficient costs or costs of a prudent operator in the circumstances of SP AusNet.

A share of SPIMS, EB Services and SPIAA's corporate costs have already been factored into the base opex and capex forecasts—accordingly an additional margin to compensate for a share of their overheads is not appropriate as it would over-recover these costs. The AER has accepted the overheads allocated to SP AusNet from these parties, except for the adjustments set out in section 6.7.

As these arrangements are either conducted at cost, or SP AusNet has removed the profit margin associated with the arrangements from its capex forecast, no related party profit margins arise in relation to this issue requiring assessment. This situation is reflected in Table 6.10.

Additionally, given the lack of common ownership, side-payments or other transactions between SP AusNet and Tenix Alliance, the AER considers it is reasonable to presume the contract price SP AusNet pays Tenix Alliance (including margin) reasonably reflects efficient and prudent costs.

Table 6.10 AER final decision—SP AusNet—Forecast contract margins (in excess of overheads) paid to related party contractors, 2011-15 total (m, $2010)

	Draft decision	Revised proposal	Final decision
Capex	-	-	-
O&M	-	-	-
Total	**-**	**-**	**-**

Source: SP AusNet initial regulatory proposal RIN templates, SP AusNet revised regulatory proposal RIN templates, AER draft decision, AER analysis.

6.6.5 United Energy

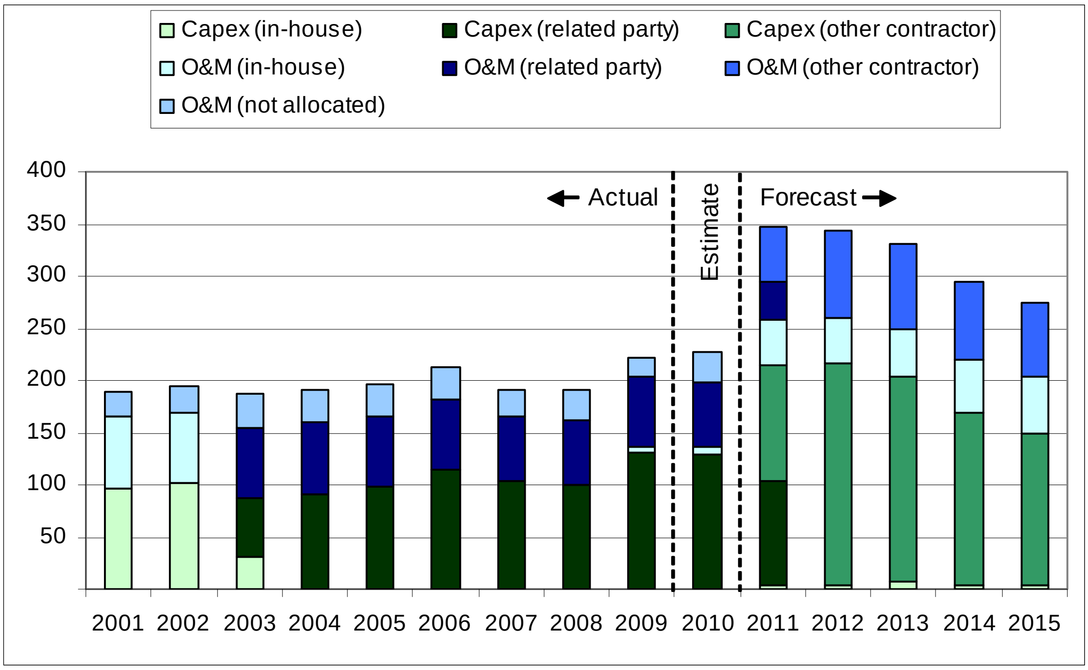
6.6.5.1 Corporate structure and outsourcing arrangements

United Energy is a wholly owned subsidiary of Power Partnerships, which in turn is a wholly owned subsidiary of United Energy Distribution Holdings (UEDH). UEDH is:

- 66 per cent owned by Diversified Utility and Energy Trust (DUET)
- 34 per cent is owned by SPI (Australia) Assets Pty Ltd (SPIAA), which is ultimately owned by Singapore Power International (SPI). SPIAA's stake in UEDH was previously owned by Alinta Ltd.

Figure 6.9 sets out SP AusNet's historical and forecast capital and O&M expenditure by service delivery method (in-house, related party contractor, other contractor). The figure shows the change in United Energy's business model from its current business model where most services are outsourced to JAM (a related party) to its new business that involves both a greater degree of in-house provision for certain services and outsourcing to non-related party contractors.

Figure 6.9 United Energy revised regulatory proposal—Historical, estimated and forecast capital, operating and maintenance expenditure (m, $2010)



Source: United Energy revised regulatory proposal RIN templates.

United Energy's revised regulatory proposal expenditure forecasts did not include any forecast margins (in excess of overheads) that United Energy expected to pay its related party contractors.

Table 6.11 **United Energy revised regulatory proposal—Forecast contract margins (in excess of overheads) paid to related party contractors (m, $2010)**

	Total 2006-10	2011	2012	2013	2014	2015	Total 2011-15
Capex	-	-	-	-	-	-	-
O&M	[c-i-c]	-	-	-	-	-	-
Total	**[c-i-c]**	**-**	**-**	**-**	**-**	**-**	**-**

Source: United Energy revised regulatory proposal RIN templates.

6.6.5.2 Management, corporate and financial services provided by United Energy Distribution Holdings

United Energy's current and new business model involves it outsourcing management, corporate and financial services to United Energy Distribution Holdings (UEDH). UEDH provides some of these services itself, and further outsources other services to specialist providers which are related parties to United Energy. These further outsourcing arrangements are:

- executive management services provided by Pacific Indian Energy Services (PIES) pursuant to a management services agreement (MSA)
- treasury and financial services provided by AMP Capital Investors (AMPCI) pursuant to a financial services agreement (FSA), and
- management and investment services provided by DUET.[239]

AER draft decision

Presumption threshold

In the draft decision, the AER considered that it could not presume that these arrangements reflect efficient costs or costs that would be incurred by a prudent operator in the circumstances of United Energy, considering:

- as United Energy is owned by UEDH, United Energy did not have an incentive to enter into an arm's length arrangement with UEDH
- given the common ownership between UEDH, PIES, AMPCI and DUET, UEDH also had an incentive to enter into non-arm's length arrangements with these related parties when it further outsourced the services outlined above, and
- the AER understood that neither the arrangement between United Energy and UEDH, or the arrangements between UEDH and PIES, AMPCI or DUET were procured via a competitive open tendering process in a competitive market.

Related party margin

[239] Specifically, the management and investment services are provided by AMPCI Macquarie Infrastructure Management No.1 and AMPCI Macquarie Infrastructure Management No.2, as responsible entities for DUET. United Energy, *Initial regulatory proposal--Appendix J1*.

United Energy stated that there is no profit margin added by UEDH in the services it provides itself to United Energy, nor was there any (further) profit margin in the services UEDH procures from related parties and on-provides to United Energy. Further, it was clear from United Energy's proposal, that there is no profit margin charged by PIES to UEDH. Accordingly, the AER noted there were not margins in excess of overheads in relation to these services that required scrutiny. However, it was not clear whether or not a profit margin was added by AMPCI or DUET in the services it provides UEDH. A case for a profit margin in these arrangements had not been established.

In the draft decision, the AER did not accept the DUET and AMPCI fees charged to UEDH and included within United Energy's opex forecast.

United Energy revised regulatory proposal

United Energy did not accept the draft decision's rejection of these fees and provided additional information (including reports from KPMG) on these costs in its revised proposal. United Energy's revised proposal is explained in section 6.7.2.

AER considerations and conclusion

This issue is discussed in section 6.7.2. In summary, the AER accepts United Energy's proposed DUET and AMPCI fees in the opex forecast except for:

- the DUET and AMPCI costs which United Energy's auditors have not been able to verify, and
- the double-counting of the AMPCI costs within United Energy's revised proposal opex forecast.

6.6.5.3 Operating services agreement with Jemena Asset Management (current business model)

On 23 July 2003, United Energy and UEDH entered into an operating services agreement (OSA) with Jemena Asset Management (JAM).[240] The agreement specified an initial three year period ending on 30 June 2006, followed by a first renewal period of five years ending on 30 June 2011. Both dates occur six months into a new regulatory control period.

Under the agreement, JAM is the exclusive provider to United Energy of the services listed in the agreement. The scope of the services provided under the OSA are extensive and include network planning, construction, management, operation, maintenance and engineering as well as customer interface services. Initially, JAM also provided regulatory services to United Energy, however this function has transferred to PIES on 1 April 2009 following an amendment to the agreement.

United Energy pays JAM a fixed annual opex fee which is adjusted annually in accordance with CPI and other factors (such as extreme weather events). JAM retains any savings in actual opex, or conversely bears any overspend. Capex fees are divided into fixed capital expenses and variable capital expenses and are subject to budgets which are prepared by JAM and submitted to United Energy for approval. The fixed

240 Specifically, the contract is with Jemena Asset Management (6) (JAM (6)). JAM (6) was previously known as Alinta Asset Management, and before that Alinta Network Services.

capex fee is adjusted annually in a similar manner to the opex fee. The variable capex fee is calculated in accordance with a schedule of rates agreed annually between the parties.

JAM acquires a number of services from other related parties in the Singapore Power group in order to facilitate its provision of services under the agreement.

AER draft decision

Presumption threshold

The AER considered while there is some common ownership between United Energy and JAM, there may not be an incentive for United Energy to enter into an arrangement with JAM on non-arm's length terms.

JAM is wholly owned by Singapore Power. Whereas, United Energy (through UEDH) is majority-owned by DUET and minority-owned by Singapore Power. In commenting on the establishment of the OSA, United Energy states:

> DUET derives 66 cents in every dollar of earnings from UED. It follows that an uncommercial service agreement if it existed would damage that flow of earnings to DUET as the majority shareholder of UED.[241]

As the AER set out in its conceptual approach to assessment outsourcing arrangements, where a related party contractor is owned by a service provider's minority shareholder, the service provider's majority shareholder may not have an incentive to permit the service provider to enter into a non-arm's length contract as any value or inflated profits transferred out of the service provider would not be to the benefit of the majority shareholder. This reasoning was consistent with United Energy's statement above.

However, the AER also noted that even in this scenario, where the negotiations over an operating services agreement did not occur independently of some other transaction, this lessens the assurance that contract terms reflect arm's length terms because the terms that one party is willing to accept for the operating agreement will be dependent on the terms of the other transaction.

The negotiations over the OSA occurred as part of a larger transaction involving an ownership re-organisation of United Energy known as the 'Shearwater transaction'.[242] Further, United Energy acknowledged that JAM was appointed as the operator under the OSA without any tender process.[243] Accordingly, under the presumption

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[241] United Energy, *Initial regulatory proposal--Appendix J1*, p.8.

[242] The 'Shearwater transaction' was a large series of transactions which involved: Power Partnership (a company owned by Aquila and AMP) acquiring the remaining 42.95 per cent of shares in United Energy Limited that it did not previously own; Alinta and entities managed by AMP Henderson buying Aquila's 59.3 per cent interest in Power Partnership; Aquila selling its interests in its other Australian assets, namely an indirect holding in Alinta and its 48.2 per cent economic interest in the Multinet Partnership; AMP Henderson creating a new, wholesale diversified energy fund being DUET with the intention that DUET would be managed by AMP Henderson and would comprise two wholesale unit trusts whose securities would be stapled; and reorganising assets as between Alinta, United Energy and DUET. United Energy, *Scheme booklet for the scheme of arrangement between United Energy Ltd and the holders of UEL shares in relation to the proposal with Power Partnership Pty Lid*, 30 May 2003.

[243] United Energy, *Initial regulatory proposal--Appendix J1*, pp.7-8

threshold, the AER could not presume that the OSA fees reflect efficient costs or the costs that would be incurred by a prudent operator in the circumstances of United Energy.

Related party margin

The AER noted that the corporate costs of JAM had already been factored into the base opex forecast—accordingly a margin to compensate for a share of JAM's overheads was not appropriate as it would over-recover these costs.[244] Additionally, the AER was not aware of any assets owned and utilised by JAM in providing services to United Energy which are not already contained within United Energy's regulatory asset base. The existence of such assets would justify a margin being paid to JAM, but did not appear to apply here. Accordingly, following the AER’s approach a case for a margin above JAM's actual costs had not been established.

However, the AER noted that given the mostly fixed price nature of the OSA, and as a result of rising costs since the OSA was entered into, according to United Energy, JAM is currently making a loss in providing services under the agreement (referred to as a 'negative margin'). Accordingly, using JAM's actual costs results in a higher operating and capital expenditure forecasts than if the OSA fees were adopted.

On JAM's actual costs, the AER noted that under the WOBCA methodology depreciation costs associated with IT assets are being allocated by JAM to United Energy. These assets may be related to assets not already contained in United Energy's RAB. If this is the case then a margin reflecting the return on and return of these IT assets is appropriate. The IT depreciation would be the return of assets. These IT depreciation costs are currently reflected within United Energy's base opex, and consequently reflected in United Energy's forecast opex (under the AER's draft decision on United Energy's opex forecast).

United Energy revised regulatory proposal

United Energy argues that a profit margin should be added to JAM's 2009 actual costs, and purports and a report it commissioned from Frontier Economics supports this principle.

Specifically, Frontier Economics states:

> …as the provider of an unregulated service and as an entity with only some common ownership with UED, JAM will need to recover at least its costs of entering into its contract with UED. These costs will include the cost of any funds required to finance activities to be undertaken under the contract. If JAM cannot receive such a price, it will not enter into a new contract with UED. However, under the AER's 'two stage approach' to outsourcing and related party transactions, UED may not be able to recover operating expenditure in excess of a related party's costs. Given these constraints, UED may not be able to come to a new agreement with JAM for the 2011-2015 regulatory control period.[245]

[244] The AER notes that JAM's 2008 costs have been adopted for the purposes of this draft decision, however these will be updated for JAM's 2009 costs in the final decision.

[245] Frontier Economics, *Meaning and application of National Electricity Rule 6.5.6(c)—A report prepared for Johnson Winter & Slattery*, July 2010, p.10.

The specific margin proposed by JAM is [number removed c-i-c]. It supports this by reference to:

- a report by Ferrier Hodgson, submitted by United Energy to the AER in the context of its AMI application, that accordingly to United Energy demonstrates 6 per cent is a reasonable margin, and
- noting the AER's comment in the JGN final decision that benchmark profit margins extend from around 3 per cent to more than 12 per cent.

AER considerations and conclusion

A portion of JAM's overheads is already included within United Energy's opex forecast, therefore any further margin to compensate for corporate costs is not warranted. Additionally, United Energy has not identified any assets owned and utilised by JAM in the provision of services to United Energy that are not already included within United Energy's RAB. Accordingly, following the AER's approach set out in section 6.5.3, the case for a margin above JAM's direct and indirect costs has not been established.

The AER discusses the emphasis it considers should be placed on margin benchmarking in section 6.5.5.

6.6.5.4 Operating services agreement with ‘turnkey service provider’ (new business model)

When the first renewal period of the OSA with JAM ends on 30 June 2011, United Energy has informed the AER that it does not intend to renew this agreement. United Energy is taking the opportunity of the end of this agreement to move to a new business model. United Energy’s current and new business models are summarised in appendix I.

As part of its move to a new business model, United Energy has advised that it will be separating its network into two geographical regions (that is, a northern and southern region). It has undertaken a tender process to appoint a ‘turnkey service provider’ that will manage and operate one of those regions and manage the contract for the other region which will be awarded to some other party.

In this section the AER assessing the contract with the turnkey service provider.

AER draft decision

Presumption threshold

United Energy argued that its forecast has been ‘market-tested’ and so could be relied upon as being efficient. However, the AER noted that it was essentially only the tendered unit costs which had been market-tested with the other three components of its opex forecast estimated by United Energy. The AER reviewed the tendering process and was reasonably satisfied with this process. However, the AER had concerns with each of the remaining three components of United Energy’s bottom up build of its costs.

As noted, the AER reviewed United Energy’s tendering process and considered that the process adopted by United Energy appeared reasonably competitive and involved a large number of applicants. That said, the AER had some concerns with the competitiveness of this process in relation to two clauses in the current JAM contract which:

- provide JAM with a ‘right to match’ the terms of any future contract that replaces its existing contract; and

- require any contractor that replaces JAM (or some other entity) to offer to purchase at least [c-i-c] of United Energy (from Jemena) at a price determined by an independent valuer.

The AER considered that these clauses in the current contract may have dissuaded some applicants from participating in the tendering process or from rigorously competing for it under the knowledge that even if they were the preferred bidder JAM might exercise its right and end up with the contract. Additionally, the AER noted that JAM was currently disputing United Energy's interpretation of the 'right to match' clause. Part of this dispute was that JAM considered it had the right to re-tender for the entire scope of services currently provided under the OSA, and that if its exercises its right to match than United Energy is not able offer the second regional partner to a non-JAM entity. It was unclear whether or not the tender applicants were aware of this dispute in submitting their tenders, however if they were the AER noted this might have further dissuaded some applicants from participating or rigorously competing under the view that if JAM exercised its right to match than it would not even be awarded the second regional contract.

Additionally while there was not currently any common ownership between United Energy and the turnkey service provider, the interdependent negotiations between the OSA and the equity transfer lessens the extent that the AER could reasonably presume the OSA reflects arm’s length terms.

Notwithstanding the potential concerns the AER had over the competitiveness of the tendering process, and the interdependent negotiations involving the equity transfer, the fact that four consortia sought to be involved in the final stage of the tendering process indicated to the AER that the process was likely to have been reasonably competitive. Accordingly, the AER considered that the new agreement with the preferred tender applicant passed the presumption threshold and the AER could presume that the contract charges under this contract reasonably reflected the efficient costs that would be incurred by a prudent operator in the circumstances of United Energy.

United Energy revised regulatory proposal

In response to the AER's assessment of its recent tendering process, United Energy states:

- the market testing process was highly competitive, as borne out by the strong commitment of bidders, and has confirmed the market's appetite for United Energy's new business model

- under the operating services agreement (OSA), United Energy may, but is not obliged to, put a 'match' offer from a single service provider for all the services for a five year term to JAM. The market testing exercise has not triggered this right, and

- United Energy does not intend to require a new service provider or providers to take an equity stake in United Energy.[246]

AER considerations and conclusion

Based on the information provided by United Energy, it is not clear what tender applicants were informed of in relation to the 'right to match' and equity stake clauses from the existing JAM contract. Accordingly, the AER reaffirms its position that this clauses may have had some degree of lessening the competitiveness of the tender process to replace the existing JAM contract.

That said, the AER also reaffirms its other draft decision position (which is in agreement with United Energy). That is, due to the number of consortia involved in the final stage of the tendering process, the AER considers this process was likely to have been reasonably competitive. Therefore, the new agreement passes the presumption threshold and it is reasonable for the AER to presume the contract charges under this contract reasonably reflect the efficient costs that would be incurred by a prudent operator in the circumstances of United Energy.

Accordingly, the AER has accepted the component of United Energy's capex forecast that is based on the contracted capex unit costs from this new agreement.

While the AER is satisfied the equivalent contracted opex unit costs component from United Energy's opex forecast are also efficient, this is only one component from United Energy's opex forecast. The AER has not accepted United Energy's total opex forecast for the reasons set out in chapter 7 and appendix I. United Energy also argues that the AER should presume the forecast unit volumes from the outsourced opex services are also efficient because they were also market tested through the tendering process. The AER addresses this issue in appendix I.

6.6.5.5 AER conclusion

As United Energy's expenditure forecasts did not include any related party profit margins, no related party profits margin issues arose requiring assessment.

The AER has reviewed United Energy’s tendering process and considers that the process adopted by United Energy appears reasonably competitive and involved a large number of applicants.

[246] United Energy, *Revised regulatory proposal,* .pp.19-20.

Table 6.12 AER final decision—United Energy—Forecast contract margins (in excess of overheads) paid to related party contractors, 2011-15 total (m, $2010)

	Draft decision	Revised proposal	Final decision
Capex	-	-	-
O&M	-	-	-
Total	-	-	-

Source: United Energy initial proposal RIN templates, United Energy revised proposal RIN templates, AER draft decision, AER analysis

6.7 Issues and AER considerations—Assessment of related party contractors' corporate costs

In section 6.5.3, the AER set out its approach to assessing contracts that do not pass the presumption threshold, and so cannot be presumed to be efficient or prudent. This approach involves adopting the contractor's direct costs as a 'starting point' and allowing a margin on top of these costs only if there are legitimate economic reasons to do so. A reasonable allocation of the contractor's corporate and other indirect costs is one of those legitimate economic reasons.

However, this does include all possible allocations from a contractor of its indirect costs but only those indirect cost allocations which:

- are sufficiently connected to the provision of distribution services
- are for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the service provider's cost allocation method (CAM),[247] and
- the AER is satisfied reasonably reflect the capex criteria or the opex criteria, in particular the efficient costs and costs of a prudent operator in the service provider's circumstances.[248]

The outcomes from this section feeds into the base opex forecast (section 7.6.3), opex step changes (section 7.6.6 and appendix L), and capitalised overheads in the capex forecast (chapter 8).

6.7.1 AER draft decision

In the draft decision, the AER found that the only contracts not to pass the presumption threshold and which necessitated further assessment were current or former contracts with related parties.

While the AER generally accepted the related parties' corporate costs that had been allocated to the Victorian DNSPs, adjustments were made to these allocations for:

[247] NER, cls.6.5.6(b)(2) and 6.5.7(b)(2).
[248] NER, cls.6.5.6(c) and 6.5.7(c).

- management fees paid to the parent of the related party (and DNSP) because the AER was not satisfied these fees reasonably reflected the efficient costs that would be incurred by a prudent operator, and / or where the management fees did not sufficiently contribute to the provision of distribution services—adjustments were made to JEN's, SP AusNet's and United Energy's forecasts accordingly

- corporate cost categories that ‘double-count’ costs recovered elsewhere in the regulatory regime (for example, debt raising costs)—an adjustment was made to United Energy's forecasts accordingly, and

- an over-allocation of the related party's corporate costs to the DNSP—an adjustment was made to SP AusNet's forecasts accordingly

- other corporate cost categories that do not sufficiently contribute to the provision of distribution services or were not an efficient cost that would be incurred by a prudent operator—adjustments were made to JEN's and United Energy's forecasts accordingly.

The adjustments made by the AER in the draft decision are summarised in the Table 6.14 and Table 6.15.

6.7.2 Assessment of management and financial fees paid by related party contractors to parent companies

In the draft decision, the AER identified several instances of management fees paid by related party contractors to parent companies where the AER was not satisfied that the payment of such fees reasonably reflects the efficient costs that would be incurred by a prudent operator or that the fees sufficiently contributed to the provision of distribution services. These payments were:

- management fees paid by SPI Management Services (SPIMS) to Singapore Power and to the Jemena group (these fees were included within SP AusNet’s forecast opex and capex)

- management fees paid by Jemena Ltd (through SPIAA) to Singapore Power (these fees were included within JEN’s and United Energy’s forecast opex)

- management fees paid by UEDH to DUET (these fees were included within United Energy's forecast opex), and

- financial services fees paid by UEDH to AMP Capital Investors (AMPCI) (these were included within United Energy's forecast opex)

The AER excluded the portion of these fees allocated by the related party contractor to JEN, SP AusNet and United Energy from the Victorian DNSPs' opex and capex forecasts (where applicable).

Management fees paid to Singapore Power (JEN, SP AusNet, United Energy)

In the draft decision, the AER removed the Singapore Power and Jemena group fees from SP AusNet's opex and capex forecasts as SP AusNet had not demonstrated these fees were an efficient cost that would be incurred by a prudent operator, especially considering the significant management costs already incurred by SPI Management Services (SPIMS) in the absence of this additional cost. That is, SP AusNet had not provided information that demonstrated the value to SP AusNet’s customers of funding this fee to Singapore Power. Further, SP AusNet had not demonstrated that these fees sufficiently contribute to the provision of distribution services.

In removing these management fees the AER noted:

- In its last transmission determination, the AER rejected the portion of the Singapore Power fee allocated to SP AusNet's electricity transmission business as SP AusNet had not substantiated that these management costs (essentially a third tier of management in addition to SP AusNet’s board and management company) would be required by a prudent operator in SP AusNet’s circumstances.

- In the last gas distribution review, the ESCV rejected the portion of the Singapore Power fee allocated to SP AusNet's gas distribution business as the costs were not relevant to the provision of reference services.

- SP AusNet had not provided any substantive further information in its electricity distribution regulatory proposal demonstrating the efficiency and prudency of the Singapore Power fee to suggest that the AER's or ESCV's earlier positions on the fee were no longer appropriate. SP AusNet had not provided any specific information on the small fee paid to the Jemena group.

A management fee for similar services is paid by Jemena Ltd (through SPIAA) to Singapore Power. In their initial regulatory proposals, JEN provided limited details on this fee and United Energy provided no specific information about this fee other than the cost it incurs.

In the draft decision, the AER removed these fees from JEN's and United Energy's base opex on the grounds that:

- Based on the limited information provided, the AER considered the services provided by Singapore Power in exchange for the management fee are strategic in nature and relate to the corporate strategy and direction of the Jemena group. The AER considered that this fee appears to primarily benefit the Jemena group's shareholders rather than consumers, and is not sufficiently connected to the provision of distribution services

- JEN and United Energy had not substantiated the efficiency or prudence of these fees. Given the significant management and corporate costs already incurred by Jemena Ltd and JAM, the AER was not satisfied that this additional management cost reflects the efficient costs or a cost that would be incurred by a prudent operator.

The Victorian DNSPs' responses in their revised regulatory proposals are as follows:

- JEN accepted that the management fee paid to Singapore Power does not relate to the provision of standard control services and removed this from the opex forecast in its revised regulatory proposal.[249]

- SP AusNet stated the Singapore Power and Jemena group management fees are paid by SPIMS and its subsidiary, respectively, but that they are not recovered through or incurred by SP AusNet. Accordingly, the AER's draft decision to remove these fees was an error of fact because they were not included in SP AusNet's initial regulatory proposal.[250]

- United Energy did comment directly on this issue but it did remove the fee from the current business model counterfactual opex forecast in its revised proposal.[251]

The AER has reviewed JEN's removal of the management fee from its opex forecast (which included the updating of this fee for 2009 actual costs) and did not identify any issues. Accordingly, the AER accepts JEN's incorporation of the AER's draft decision to exclude the fee from its proposed forecast opex in its revised regulatory proposal [c-i-c] nominal 2009, annual adjustment to the base opex). JEN also removed the management fee from its reported 2009 opex for the purposes of the efficiency carryover mechanism (ECM) calculation. This ECM adjustment is considered in chapter 13.

SP AusNet stated that the AER's draft decision to remove the Singapore Power fee from its expenditure forecasts was an error of fact because the fees were not included within its initial regulatory proposal. While the fee is paid by SPIMS to Singapore Power, SP AusNet stated it is not recovered from SP AusNet and accordingly is not included in the reported expenditure in its regulatory accounts. SP AusNet illustrated the link between the costs paid by SP AusNet and the revenue earned by SPIMS (which can be split into SPIMS actual employee remuneration costs and performance fees) to demonstrate that the Singapore Power fee is not on-charged to SP AusNet. It also provided the invoices between SP AusNet and SPIMS in response to a request from the AER.[252]

SP AusNet stated that when the contractual arrangements between it and SPIMS were revised, the new pricing arrangements did not include the recovery of the Singapore Power management fee.

SP AusNet also stated that the small management fee paid to the Jemena group (by SPIMS' subsidiary, EB Services) is not recovered from SP AusNet and so the AER's removal of this fee was also an error of fact.

The AER has reviewed the material provided by SP AusNet in and subsequent to its revised regulatory proposal and is satisfied that the Singapore Power and Jemena group management fees are not incurred by SP AusNet and not included within SP AusNet's regulatory accounts (the starting point for the AER's base opex and

[249] JEN, *Revised regulatory proposal*, p.103.
[250] SP AusNet, *Revised regulatory proposal—'Revised related party arrangements' appendix*, pp.14-15.
[251] United Energy, *Revised regulatory proposal—Appendix C16.*
[252] SP AusNet, *Email to AER*, 8 September 2010.

capitalised overheads forecasts). Accordingly, no adjustment has been made in respect of these management fees in this final decision.

While United Energy did not comment directly on this issue appears to have accepted the draft decision exclusion of the Singapore Power fee from the base opex forecast (in the AER's counterfactual opex forecast), given it excluded the fee from its own counterfactual opex forecast. For the reasons set out in the draft decision the AER maintains that United Energy's management fee is to be excluded from the base opex in this final decision.

The excluded amount in the draft decision was based on the United Energy's 2008 costs as itemised and reviewed by PWC. While the AER had intended to update this amount for the 2009 actual cost, United Energy has informed the AER that an equivalent PWC report on 2009 costs was not commissioned by JAM.[253] Accordingly the AER has not been able to update this amount and has used the 2008 amount as the basis of the excluded amount in this final decision.

This adjustment results in an annual adjustment of [c-i-c] to United Energy's base opex, or [c-i-c] over the regulatory control period, from what would have otherwise been included in the AER's counterfactual opex forecast for United Energy.

Management fees paid to DUET and financial services fees paid to AMPCI (United Energy)

UEDH sources management services from its majority shareholder DUET (or more specifically from AMPCI Macquarie Infrastructure, the responsible entity of DUET). UEDH also sources treasury and financial services from AMP Capital Investors (AMPCI).

AER draft decision

The AER stated that the details provided regarding the management services arrangement with DUET in United Energy's initial regulatory proposal was limited.

United Energy's initial regulatory proposal only stated that these fees are for ‘management and investment services to UEDH’ and that DUET plays an 'important role' in the management of UED. United Energy stated that DUET provides oversight and management of investors' capital and incurs a range of related corporate governance and regulatory compliance costs.[254]

However, United Energy's initial regulatory proposal:

- did not explain why United Energy chose to outsource this service and why its own management team (including the UEDH and PIES management staff) were not capable of providing these services themselves
- did not explain the process under which the services were procured (for example, whether the services were procured using a competitive tender)

[253] United Energy, *Email to AER*, 6 September 2010.
[254] United Energy, *Initial regulatory proposal--Appendix J1*, pp. 2–6.

- did not explain how the management fee is calculated and how this relates to the underlying costs of DUET
- did not clearly explain the amount of the management fees which are included in its expenditure forecasts,[255] and
- did not include a copy of the contract[256]

On the basis of the limited information provided by United Energy, the AER was not satisfied that the management fees paid to DUET reasonably reflects the efficient costs that would be incurred by a prudent operator in the circumstances of United Energy. Accordingly, the AER did not include these fees in its estimate of United Energy's base opex forecast.

On the financial services agreement (FSA) with AMPCI, the AER considered there appeared to be a substantial overlap between the services provided under that agreement and the separate debt raising costs allowance sought by United Energy in its initial regulatory proposal. Given this apparent ‘double-counting’ of costs within United Energy's expenditure forecasts, the AER was not satisfied that the inclusion of these financial services fees in addition to the separate debt raising costs allowance within United Energy's opex forecast reasonably reflects the efficient costs that would be incurred by a prudent operator. To address this 'double-counting', the AER permitted a debt raising cost allowance in United Energy's opex forecast but excluded the AMPCI fees associated with the FSA.

United Energy revised regulatory proposal

United Energy accepted that its initial regulatory proposal did not provide sufficient detail regarding the services that are provided by AMPCI and DUET. It provided the following information.

In relation to AMPCI, UEDH obtains treasury and financial services in accordance with the FSA. The services are:

- financial services (treasury)
- transaction services associated with capital raisings by the company. These services are advisory in nature
- additional services, not necessarily related to financing issues. Payments for additional services are made according to hourly rates.[257]

United Energy stated the services provided by AMPCI are not remunerated through the debt raising allowance provided by the AER, which does not encompass the

[255] United Energy's consolidated budget model contained a line item labelled 'shareholder costs' which feed into its opex forecast. This amount was [c-i-c] per annum or [c-i-c] over the forthcoming regulatory control period. However, while not clear from United Energy's initial proposal, this line item appeared to be the combination of the management fees paid to DUET and the financial services fees paid to AMPCI.

[256] This arrangement was the only transaction between UED or UEDH and a related party where United Energy did not include the contract in its initial regulatory proposal.

[257] United Energy, *Revised regulatory proposal*, pp. 65-67.

operating expenditure associated with routine treasury services. The treasury services provided by AMPCI are defined to include the activities described below and do not already included within debt raising activities:

- drafting and negotiating financing documentation
- debt compliance advice and reporting, including treasury reports containing information as agreed
- liaison with ratings agencies
- providing treasury and economic information
- developing and reviewing capital structure and financing strategies, and
- developing and reviewing interest rate and currency hedging strategies.[258]

United Energy also commissioned reports from KPMG on services it received from both AMPCI and DUET. For the latter, United Energy states KPMG's report explains and evidences the nature and necessity of the services provided by DUET and that services provided by DUET are consistent with the requirements of a prudent operator in the circumstances of United Energy acting efficiently.[259]

United Energy also provided:

- a copy of a letter from DUET detailing the services that are provided by DUET
- a copy of the FSA between United Energy and AMPCI for the provision of services
- an audit opinion from Ernst & Young, confirming the costs incurred by United Energy in relation to services provided by DUET and AMPCI
- an opinion from KPMG that the costs incurred by United Energy in relation to services provided by DUET and AMPCI relate to the provision of standard control services and properly fall within the definition of operating expenditure defined by the NER. United Energy stated KPMG's opinion also confirms that there is no double counting of these costs with any other regulatory allowance.[260]

AER considerations and conclusion

In responding to one of the AER's criticisms in the draft decision (that United Energy's initial regulatory proposal did not explain why it chose to outsource the particular management services to DUET), KPMG explains that, in principle, United Energy could provide these services in-house and incur standalone costs. This,

[258] ibid., pp. 66-67.
[259] ibid
[260] ibid., p. 68.

KPMG submitted, would not reflect the actions of a prudent operator seeking to deliver efficient costs.[261]

KPMG explains that as DUET owns multiple networks, by centralising these management services within DUET, each individual group business is able to gain access to:

- levels of expertise and capital market capability that would be difficult to otherwise access by smaller, standalone entities such as United Energy and hence increase the likelihood of higher quality advice and more efficient business outcomes, and

- economies of scale by sharing the associated costs of access to this expertise that are generally not directly proportional to the size of the business of a group (that is, the economies of scale of sharing costs that tend to be "fixed").[262]

The AER has reviewed KPMG's reasons for United Energy outsourcing management services to DUET and considers that these are consistent with a total forecast opex that reasonably reflects the opex or capex criteria, the good business practices of a prudent operator in United Energy's circumstances, for the reasons outlined by KPMG.

That said, as the costs associated with these management services are allocations of DUET's total costs, these costs must be scrutinised to determine whether only costs that are sufficiently connected to the provision of distribution services are being allocated to United Energy, and that this amount is then properly allocated to standard control services in accordance with United Energy's CAM.

It is clear from KPMG's report that the services provided by DUET to United Energy are the same as the services DUET provides to Multinet, a gas network in Victoria which is also majority owned by DUET (the similarity of these services was not apparent from United Energy's initial proposal).[263] Several areas of KPMG's report refer to a similar report that Multinet commissioned from KPMG on the services provided by DUET to Multinet. That report was commissioned in the context of the last Victorian gas access arrangement review (GAAR).

In the last GAAR, the ESCV found that KPMG's report on the DUET services did not disaggregate costs by reference to particular activities or services, such that the ESCV would be able to form its own view on to whether they are costs of providing the reference services. The ESCV considered:

> The result is that it is not possible to determine, in relation to actual costs that have been identified, whether the activities of functions to which the costs relate are activities or functions necessary for the provision or delivery of Reference Services. Not all functions and costs of a parent entity that arise due to an interest in a gas distribution business are necessarily costs of providing Reference Services.

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[261] United Energy, *Revised regulatory proposal—Appendix C12 'KPMG, UEDH—Services delivered to United Energy by DUET, July 2010'*, p.3.

[262] United Energy, *Revised regulatory proposal—Appendix C12* ,p.15.

[263] United Energy, *Revised regulatory proposal—Appendix C12* ,p.5.

As examples of costs that are not incurred in the provision of reference services, the ESCV identified:

- costs associated with, or arising from, management of the equity holders' ownership interests in the distribution business. This would include costs arising from activities such as the parent entity's management of its own financing arrangements, the parent entity's own governance costs and statutory reporting to the extent that these costs are over and above any costs incurred in meeting the statutory obligations, and other required functions of the subsidiary distribution business, and

- costs incurred in activities that would be undertaken by any arm's length equity owner in monitoring and scrutinising the management, operations and results of the subsidiary distribution business.

In assessing the actual DUET costs (and AMPCI, MGH and PIES costs) identified by Multinet, the ESCV concluded:

> This amount will almost certainly include costs for activities which would not properly be considered costs of providing Reference Services. On the other hand, it is not possible on the basis of the information that has been provided to determine how much of these costs are costs of providing the Reference Services and how much are not.

Accordingly, the ESCV did not make an explicit adjustment for this issue. However, the ESCV noted not all of the DUET, AMPCI, MGH and PIES costs reported by Multinet could be verified by Multinet's auditors. The ESCV only accepted the amount the auditors could verify.

The AER notes the ESCV's view that the DUET costs reported by United Energy are likely to include shareholder costs which are not sufficiently related to the provision of distribution services. However, the AER also is not in a position to make an explicit adjustment for this issue due to the information provided by United Energy.

That said, the AER has also found that not all of the DUET, AMPCI, Macquarie and PIES costs reported by United Energy have been verified by its auditors. Consistent with the ESCV's position, the AER has only allowed that amount which has been verified by United Energy's auditors.

United Energy also submitted a report by KPMG on the financial services provided AMPCI under the FSA. The report explained that under the FSA, AMPCI provides three types of services to UEDH (and ultimately to United Energy). KPMG also explained that of the three types of services, the $[c-i-c] per annum proposed by United Energy only relates to the treasury and other ad-hoc services for which there is no 'double-count' with the debt raising cost allowance. KPMG explained that United Energy had not sought recovery of the transaction services provided under the FSA, the third type of service provided.

In the draft decision, the AER was concerned about a double-counting between the FSA fees and the debt raising cost allowance. The AER has reviewed KPMG's report and is satisfied that the two types of services for which the $[c-i-c] per annum relates does not constitute a double-counting of the debt raising cost allowance.

However, based on the information in KPMG's report, it appears that United Energy's initial proposal double-counted the FSA fees themselves. In the draft decision, the AER stated:

> The AER notes that in its estimate of United Energy's base opex it has included the 'FSA—Treasury front office' cost category from United Energy's internal corporate budgeting model. Accordingly, despite the exclusion of the FSA fees paid to AMPCI, the AER's estimate of United Energy's opex already appears to cover the internal administrative costs associated with debt raising that would be expected to be incurred by a prudent operator.

KPMG's report makes clear that, contrary to the AER's understanding at the time, the 'FSA—Treasury front office' was not administrative costs associated with the FSA, but the FSA fees themselves. This double-counted AMPCI's costs, as the 'shareholder costs' in United Energy's initial regulatory proposal already included AMPCI's costs associated with these services provided to United Energy. United Energy's initial regulatory proposal shows that the FSA services are the only services provided by AMPCI to United Energy.

As the AER accepts the DUET, AMPCI, Macquarie and PIES costs (that is, the 'shareholder costs') in United Energy's revised regulatory proposal—subject to the exclusion of costs that cannot be verified by United Energy's auditors—the AER has removed the 'FSA—Treasury front office' costs to avoid double-counting AMPCI's costs in providing the FSA services to United Energy.

The AER notes this is not inconsistent with KPMG's report. KPMG only stated that there was no double-counting between the FSA fees and the debt raising cost allowance and did not analyse whether there was a double-counting of the FSA costs themselves within United Energy' proposed forecasts. The AER notes that analysis was outside KPMG's terms of reference.

6.7.3 Allocation of related party contractor's corporate costs to the DNSP

The cost allocation methodology (CAM) process involves the allocation of a DNSP’s costs, including indirect costs, between standard control, alternative control, negotiated, and unregulated services. In short, the CAM allocates costs which 'enter' the DNSP.

However, another issue is the allocation of corporate or other indirect costs to the DNSP itself, where corporate services are provided to the DNSP by a related party contractor. This issue arises because each Victorian DNSP is part of a larger corporate group which engages a specialist corporate services entity to provide management and corporate services to each Victorian DNSP, namely:

- CHED Services in relation to CitiPower and Powercor
- Jemena Ltd and JAM in relation to JEN
- SPIMS in relation to SP AusNet, and
- UEDH and PIES in relation to United Energy

In the draft decision, the AER only identified issues in relation to the allocation of SPIMS's corporate costs to SP AusNet.

Allocation of SPI Management Services' costs to SP AusNet

AER draft decision

The AER had concerns with the SP AusNet group's allocation of SPIMS costs between its regulated electricity distribution, regulated gas distribution, AMI, unregulated distribution, regulated transmission, unregulated transmission, and non-SP AusNet business segments.

SPIMS's costs are allocated between these business segments based on a management survey of 'effort'. This survey is completed regularly (currently every three months) so the percentage allocations between segments also change regularly. The AER noted that the results of the survey appeared to show that when management exerts more effort on different business segments in the lead-up to the SP AusNet group's regulatory proposal for that business segment, there is an above-average allocation of management costs which are fed into the base year opex used to set the operating forecast for that reset (and the capex forecast to the extent these costs are capitalised).

Further as different base years are used for different resets (and the allocations between business segments change annually), this leads to the situation where accepting the outcome of SP AusNet's allocation method for the Victorian electricity distribution determination would result in the SP AusNet group recovering more than 100 per cent of SPIMS's costs.

For example, the AER noted that 22 per cent of SPIMS's costs fed into the 2006 opex base year used in the last gas access arrangement review (GAAR) by the ESCV. However, only 12 per cent of SPIMS's costs in 2009 are being allocated to gas distribution, resulting in a greater proportion of SPIMS's costs being allocated to other business segments in 2009, such as electricity distribution. SP AusNet proposed 2009 as the base year for this electricity distribution determination (and this has been accepted by the AER).

The draft decision set out the opex base year allocations adopted in the last electricity transmission, gas distribution and AMI reviews, compared to the same business segment's 2009 allocations (replicated in Table 6.13).

Table 6.13 SP AusNet initial proposal—Allocation of SPI Management Services costs to individual SP AusNet group business segments under its survey of management effort method (per cent)

Business segment	Base year allocation	2009 allocation	Difference
Transmission regulated	35 (2006-07)	26	9 less
Gas distribution regulated	22 (2006)	12	10 less
AMI regulated	5 (2008) [a]	9	4 more
Electricity distribution regulated	31—Opex (2009) 15—Capex (2009) 46—Total (2009)	31—Opex (2009) 15—Capex (2009) 46—Total (2009)	-
2009 allocation			
Transmission unregulated (2009)	2	2	-
Distribution unregulated (2009)	4	4	-
SP AusNet (2009)	1	1	-
Total	**115**	**100**	**-**

Source: SP AusNet.

The AER considered that in future electricity and gas determinations it may be more appropriate to allocate SPIMS's costs to each business segment using an average of the management effort percentage allocations over several years for that business segment. The AER considered this approach would result in more stable allocations between years, and consequently an allocation into the base year of each reset that is more representative of a typical year's costs.

However, although the AER and ESCV accepted the management survey allocations in the last electricity transmission and gas resets, to apply that average approach in this determination would now result in the SP AusNet group recovering more than 100 per cent of SPIMS's costs.

Accordingly, the AER adopted a 'residual' approach for the early years of the forthcoming electricity distribution regulatory control period, allocating to electricity distribution the SPIMS costs that are not already being recovered through the current electricity transmission, gas distribution or AMI determinations or being allocated in 2009 to unregulated or non-SP AusNet activities.[264] This resulted in a base year adjustment to reflect 31 per cent of costs being allocated to electricity distribution (whereas SP AusNet's management survey method resulted in 46 per cent to the base

[264] The AER assumed that 5 per cent of SPIMS costs are being recovered through the AMI determination. This percentage equates to SP AusNet's allocation of SPIMS's cost to AMI in 2008, though the AMI budget itself was not set using a 'base year' approach.

year), split between 21 per cent opex and 10 per cent capex.[265] To give effect to the allocation of SPIMS costs to electricity distribution using a 'residual approach' at the start of the regulatory control period, and an 'average approach' after the current electricity transmission, gas distribution and AMI determinations have finished, the AER added back a (positive) step change to the opex and capex forecasts towards the end of the forthcoming regulatory control period. This was necessary to transition to the average approach for the allocation of group costs to SP AusNet's electricity distribution network.

The combination of the (negative) base adjustment and (positive) step changes reduces SP AusNet's total opex forecast by $9.6 million and reduces the total capex forecast by $4.7 million.

SP AusNet revised regulatory proposal

SP AusNet did not agree with the draft decision's re-allocation of SPIMS' corporate costs on the basis that the AER's consideration of SP AusNet's whole of business costs:

- is an irrelevant consideration
- is not captured under one of the opex factors, and
- is inconsistent with the NEO and revenue and pricing principles.

Further, SP AusNet argues that:

- it has already returned some efficiencies to consumers
- it does not have an incentive to allocate costs inefficiently given the application of the EBSS
- the AER's approach results in scale or synergy gains being passed through immediately to consumers
- the AER's use of percentages instead of actual amounts is flawed, and
- the AER's approach predetermines the work or management effort and that any errors introduced by SP AusNet's approach is not significantly material and is transitory in nature.[266]

SP AusNet's revised proposal includes the same SPIMS' costs as its initial proposal.[267]

AER considerations and conclusion

The AER notes that there were different reasons behind the two adjustments made in the draft decision:

[265] The relative proportions of the opex and capex split are consistent with SP AusNet's allocations in 2009.

[266] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.13-25.

[267] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.15, 25.

- the 'residual' adjustment—which sought to correct for the acceptance of an over-estimate of SPIMS' recurrent costs in the opex forecasts in the SP AusNet group's previous electricity transmission, gas distribution and AMI determinations, so that in total the SP AusNet group would not recover more than 100 per cent of SPIMS costs, whereas

- the 'average' adjustment—which sought to adjust SP AusNet's reported expenditure for non-current costs in its base opex forecast. This adjustment was not a criticism of SPIMS' ABC allocation methodology. That is, the AER accepts that in the lead up to the submission of a regulatory proposal, SP AusNet's management would be expected to exert more 'effort' on the electricity distribution business and so more electricity distribution costs would be expected during this time. However, as these costs would be non-recurrent in nature, the 'average' adjustment in the draft decision excluded these non-recurrent costs from the base opex forecast.

The AER has considered each of SP AusNet's criticisms of the draft decision position on this issue which predominantly relate to the residual adjustment. In summary, the AER accepts some of SP AusNet's criticisms as they relate to the AER's 'residual' adjustment, it does not accept SP AusNet's criticisms as they relate to the 'average' adjustment.

In this final decision the AER has maintained the average adjustment to the base opex and not applied the residual adjustment.

Additionally, SP AusNet proposed two potential follow-on effects of the average adjustment which the AER did not consider in the draft decision:

- that the non-recurrent costs removed from the base opex should be added back as an opex step change, but only in the year's they are expected to be incurred (with equivalent adjustments made to the capex forecast)—the AER agrees with this adjustment

- that the non-recurrent costs removed from the base opex should be removed from the actual 2009 opex for the purposes of measuring efficiencies under the efficiency carryover mechanism (ECM)(consistent with the treatment of other non-recurrent costs incurred in the base year)—the AER does not agree with this adjustment. Unlike other non-recurrent costs, regulatory submission costs (including management labour costs) are already provided for either implicitly or explicitly in the forecast.[268] Therefore, no adjustment is needed to the actual 2009 costs in order for the forecast and actual costs to be measured on a like-for-like basis, given the forecast already includes these costs.

SP AusNet's revised proposal states that if the AER intends to adopt its averaging approach then these two additional adjustments to the opex step changes and ECM

[268] The AER has explicitly provided an allowance for non-recurrent regulatory submission costs in this decision by including these costs as an opex step change. The ESCV implicitly provided for regulatory submission costs in the last EDPR by not removing regulatory submission costs from the opex base year.

calculation are needed.[269] The AER agrees with SP AusNet in respect of the first adjustment, but not the second adjustment, for the reasons outlined above. The AER has incorporated the opex step change follow-on adjustment in this final decision.

The AER responds to each of the specific criticisms raised by SP AusNet, below.

SP AusNet's revised proposal argued the draft decision's analysis of the ABC allocation methodology is an irrelevant consideration as the AER's analysis should focus on assessing the efficiency of SP AusNet's electricity distribution business (not the overall efficiency of the SP AusNet group), and that to be of relevance the AER's analysis should be captured by either the benchmarking or actual historical cost opex and capex factors.[270]

The AER agrees that its role is to assess whether the DNSP's (in this case, the SP AusNet group's electricity distribution business') proposed total forecast capex and opex reasonably reflects the capex criteria or the opex criteria. As outlined in section 6.5.3.5, the AER considers the 'circumstances' of the DNSP, to which the prudency criterion references, includes its ownership circumstances. So the fact that SP AusNet (the DNSP) is part of the SP AusNet group is relevant to the assessment of expenditure forecasts.

That said, the AER notes that each of SP AusNet's criticisms under the heading 'Legal view of NEL / NER' in its revised regulatory proposal appear to only relate to the residual adjustment from the draft decision which the AER has not applied in this final decision. In any case, these criticisms do not apply to the average adjustment which:

- focuses on the efficient costs of the DNSP (and not the efficiency of the overall SP AusNet group). The inclusion of non-recurrent costs in each year of the opex and capex forecast does not reasonably reflect efficient costs of the DNSP, and

- considers the actual and expected costs of the DNSP (and not the SP AusNet group's whole of business actual and expected costs). The average adjustment does not question the allocation of SPIMS' costs to the DNSP. Rather, it questions whether it is appropriate to project these costs forward without any amendment to remove non-recurrent management costs.

SP AusNet's revised regulatory proposal argues that it has already returned some efficiencies from the creation of SPIMS to consumers.[271] The AER considers the achievement of this outcome depends on SP AusNet's expenditure forecasts being determined appropriately. In particular, the inclusion of non-recurrent costs in each year of the opex and capex forecast would negate the pass through to consumers of some of the efficiency benefits that would otherwise be passed through.

SP AusNet's revised proposal argues that it does not have an incentive to allocate costs inefficiently given the application of the EBSS will ensure any increase in the base opex is off set by a lower EBSS bonus.[272] However, the AER notes that given

[269] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, p.25.
[270] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.16-17.
[271] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.17-22.
[272] SP AusNet, *Revised regulatory proposal—Appendix: Revised related party arrangements*, pp.22-23.

SP AusNet capitalises part of SPIMS' costs, an incentive exists for the SP AusNet group to allocate an above average amount of management costs to its electricity distribution business in 2009 and to not remove the non-recurrent component when projecting its capex forecast. The absence of an EBBS applying to capex means there is no penalty to counter the inflated component of the capex forecast, to the extent this may be the case.

Specifically, SP AusNet's arguments:

- that the AER's approach results in SP AusNet having to pass on any scale or synergy gains immediately to consumers
- criticising the use of percentages versus actual amounts
- criticising the AER's approach pre-determining the work or management effort,

appear to be linked to the residual adjustment.

SP AusNet also submitted that if the AER adopts its averaging approach, certain adjustments to the opex step changes and ECM calculation must be made. As mentioned above, the AER agrees with SP AusNet on the opex step change adjustment but not the ECM calculation. The AER has made the opex step change follow-on adjustment in this final decision.

Applying the 'average' adjustment to remove the non-recurrent management costs from the base opex forecasts and adding these costs back as step changes in years 2014 and 2015 results in a downwards adjustment of $4.5m to SP AusNet's total forecast opex over the forthcoming regulatory control period. Making the equivalent amendments to the total forecast capex results in a downwards adjustment to SP AusNet's total capex forecast of $2.2m.

6.7.4 Assessment of corporate strategy and IT depreciation costs incurred by related party contractors and allocated to DNSPs

Corporate strategy costs (JEN, United Energy)

This section considers the financial strategy, investment analysis and energy investments cost categories which are enterprise support function (ESF) costs (that is, corporate costs) incurred by Jemena Ltd, and allocated to JEN and United Energy under the Jemena group’s whole of business cost allocation (WOBCA) methodology.

AER draft decision

Prior to the draft decision, the AER sought further information from JEN on why each of these cost categories is allocated to the provision of distribution services. JEN provided descriptions of each of the cost categories in response. Having reviewed JEN's response, the AER considered that these costs were of a strategic nature and primarily to the benefit of the DNSPs' shareholders rather than its customers.[273] The AER concluded:

[273] AER, *Draft decision*, pp.206-208.

> Overall, the AER considers that Jemena has provided insufficient information on the nature of the financial strategy, investment analysis and energy investments costs to substantiate that these are costs sufficiently connected to the provision of distribution services so as to be recoverable under its standard control opex forecasts. Even if these were sufficiently connected to the provision of distribution services, the AER notes that a question would still remain as to whether they are efficient costs that would be incurred by a prudent operator in Jemena's (and United Energy's) circumstances. Based on the information provided, the AER is not satisfied that this is the case.[274]

Given these considerations, the AER's draft decision did not include the financial strategy, investment analysis or energy investments cost categories in JEN's base opex or the financial strategy and investment analysis cost categories in United Energy's base opex.[275] This resulted in a $[c-i-c]m and $[c-i-c] annual reduction in JEN's and United Energy's base opex (under the AER's counterfactual cost build-up for United Energy), respectively.[276]

JEN and United Energy revised regulatory proposals

JEN did not agree with the AER's exclusion of these costs and in its revised regulatory proposal:

- made several general observations on the AER's approach to these costs
- included more detail on each of these costs, and
- referred to a UMS report it commissioned which found that JEN's non-field and corporate overheads benchmarked favourably against its peers.[277]

United Energy did not respond directly to this issue.

AER considerations and conclusion

JEN's general observations are that:

- it is not possible to distinguish between activities that are to the benefit of owners and those that are to the benefit of network users.
- the AER's rejection of the financial strategy costs seems at odds with prudent corporate practices such as keeping abreast of changes in accounting standards and developing its systems accordingly, and
- the AER's view that JEN has not shown that the cost centres are directly related to providing distribution services is not relevant in relation to corporate overheads.[278]

The AER responds to each of JEN's general observations in turn.

[274] AER, *Draft decision*, p.208.
[275] The Jemena group's whole of business cost allocation (WOBCA) method allocates financial strategy and investment analysis costs to United Energy but not energy investments.
[276] AER, *Draft decision*, p.208.
[277] JEN, *Revised regulatory proposal*, pp.108-114.
[278] JEN, *Revised regulatory proposal*, p.109.

The AER disagrees with JEN's view that it is not possible to distinguish between activities that benefit owners and activities that benefit users. For example, the ATO's Taxation Ruling 1999/1 on international transfer pricing for intra-group services states that services can be distinguished and categorised as either 'non-chargeable activities', 'specific benefit activities' or 'centralised activities'. The ATO states that included within non-chargeable activities are those functions undertaken by one member of a corporate group exclusively for its own benefit. As an example, the ATO states:

> …a parent company may undertake tasks that relate solely to its own business activities, including those conducted in its capacity as a shareholder, or ultimate shareholder, of group companies ('shareholder activities'). If the group members were independent entities dealing at arm's length with a service provider, they would not be prepared to pay for these activities or contribute to meeting their cost.[279]

On JEN's second general observation, the AER agrees that costs that enable service providers to prudently adapt their financial systems to changing reporting requirements at least cost are relevant and efficient. The draft decision did not exclude such costs.

On JEN's third general observation, the AER notes that the draft decision did not debate whether these costs were direct or indirect costs, but rather, whether they were sufficiently connected to the provision of distribution services.

JEN's revised regulatory proposal also contains some additional material on each of the cost categories excluded in the draft decision. However, JEN's revised proposal does not contain substantially new or additional material that demonstrates these costs categories are primarily to the benefit of customers and so sufficiently connection to the provision of distribution costs. Based on the additional material submitted by JEN, the AER recognises that these three ESF cost categories may contain some activities that are not shareholder activities. However, the AER considers these may be outweighed by the other ESF categories which also contain shareholder costs, yet the AER has not adjusted. The AER explores this issue further below. The AER's position in this respect is consistent with the position it reached in the JGN final decision on these cost categories.

JEN's revised proposal also does not demonstrate these are efficient costs and costs that would be incurred by a prudent operator in JEN's circumstances.

Accordingly, the AER maintains its draft decision position that the financial strategy, investment analysis and energy investments ESF costs categories are primarily to the benefit of JEN's shareholders, not its customers, and therefore are not sufficiently connected to the provision of distribution services to be included within JEN's standard control opex forecast. Further, the AER notes that even if a small fraction of these ESF costs categories could be said to be sufficiently connected to the provision of distribution services, this fraction may be outweighed by the AER's full inclusion of each of the other ESF categories, even though parts of these categories may not be sufficiently connected to the provision of distribution services. For example, the AER notes that a portion of the 'CEO', 'CFO', 'Treasury', 'Taxation', 'Business services',

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[279] Australian Taxation Office, *Taxation Ruling 1999/1—Income tax: international transfer pricing for intra-group services*, p.9.

'Internal audit and risk', and 'Finance improvement' ESF cost categories may relate to shareholder costs, though the AER has not attempted to make an adjustment to these categories. In the JGN final decision, the AER also noted its concern over the full inclusion of the CEO and CFO categories, though similarly, did not attempt to adjust these categories.

The AER also maintains its position that based on the information provided by JEN, the AER is not satisfied that these three ESF cost categories reflect efficient costs or costs of a prudent operator in JEN's circumstances.

As noted above, United Energy did not respond directly to the draft decision's exclusion of these corporate strategy costs from the AER's counterfactual cost build-up. Accordingly, the AER is not satisfied that the corporate strategy costs are also sufficiently connected to the provision of services in relation to United Energy, or reasonably reflect efficient or prudent costs. Therefore, the AER has maintained its draft decision exclusion of these costs from the counterfactual opex cost build-up in this final decision.

IT depreciation (JEN)

In the draft decision, the AER noted that under JEN's WOBCA methodology depreciation costs associated with IT assets are being allocated by JAM to JEN, and that JEN has included these IT depreciation costs within its base opex forecast. The AER considered that if these assets were not already contained in JEN's RAB, then a margin reflecting the return on and return of these IT assets is appropriate. The IT depreciation would reflect the return of assets component. The AER stated:

> At this stage the AER has not included a margin to reflect the return on these assets as it is not clear whether or not these assets are contained in Jemena's RAB or not. However, if Jemena is able to demonstrate in its revised proposal that these IT assets are not already included in the RAB, then the AER would, in its final decision, allow a margin to reflect the return on these assets. However, if Jemena is not able to demonstrate that these assets are not already in Jemena's RAB, then the AER, in its final decision, would not accept these IT depreciation costs in the base opex forecasts under the assumption that these assets are already contained within Jemena's RAB.[280]

In its revised proposal, JEN states that it has removed the IT amortisation charge from its opex forecast.[281] The AER also sought additional information from JEN on the modelling of this adjustment.

The AER has reviewed the modelling of this removal in JEN's forecast data model (appendix 18.3 of JEN's revised proposal), and JEN's response to the additional information sought on the modelling, and concludes that JEN has appropriately excluded the IT depreciation amount from both its opex forecast and actual 2009 opex for the purposes of its ECM calculation.

[280] AER, *Draft decision—Appendices*, June 2010, p.37.
[281] JEN, *Initial revised proposal—Appendix 6.1*, 20 July 2010, p.2.

6.7.5 AER conclusion

Table 6.14 and Table 6.15 summarise the adjustments made by the AER in this final decision, as they related to the corporate costs of related party contractors included within the Victorian DNSPs' opex and capex forecasts.

Table 6.14 AER final decision—Related party contractors' corporate costs—Adjustments to base opex forecast—Regulatory period total (m, $2010)

	AER draft decision	DNSP revised proposals	AER final decision
Management fees			
JEN	[c-i-c]	[c-i-c]	[c-i-c]
SP AusNet	[c-i-c]	-	-
United Energy	[c-i-c]	-	[c-i-c]
Allocation of corporate group costs			
SP AusNet	[c-i-c]	-	[c-i-c]
Corporate strategy costs			
JEN	[c-i-c]	-	[c-i-c]
United Energy	[c-i-c]		[c-i-c]
Total	**-62.3**	**[c-i-c]**	**-26.5**

Source: AER analysis

Table 6.15 AER final decision—Related party contractors' corporate costs—Adjustments to capitalised overheads forecast—Regulatory period total (m, $2010)

	AER draft decision	DNSP revised proposals	AER final decision
Management fees			
SP AusNet	[c-i-c]	-	-
Allocation of corporate group costs			
SP AusNet	-4.7	-	-2.2
Total	**[c-i-c]**	**-**	**[c-i-c]**

Source: AER analysis

6.8 AER conclusion

Outsourcing to specialist providers of a particular service is a common means by which businesses in the economy are able to gain access to economies of scale and scope and other efficiencies (for example, 'know-how'). Accordingly, service providers should be provided with effective incentives to seek out efficient and prudent outsourcing arrangements.

At the same time, the AER recognises that an incentive exists for service providers to engage in related party transactions on non-arm's length terms, with the result that the service provider's reported expenditure might be artificially inflated, and that the benefits of efficiencies realised by the service provider and its related party contractors might be retained by their shareholders for longer than intended under the regulatory regime (and potentially even indefinitely), rather than being shared with consumers after a period of time. Accordingly, the AER considers outsourcing arrangements should be assessed closely against the requirements of the NER.

In the draft decision, the AER set out a conceptual framework it had developed to assist the AER in assessing the Victorian DNSPs' operating and capital expenditure forecasts against the requirements of the NER. In developing this framework, the AER had regard to the Victorian DNSPs' proposals and the past regulatory debate on this issue.

The first stage of the AER's framework is a 'presumption threshold' designed to be an initial filter to determine which contracts it is reasonable to presume reflect efficient costs and costs that would be incurred by a prudent operator, and which contracts it is not reasonable to presume reflect efficient and prudent costs. In undertaking this 'presumption threshold' assessment, the AER considers the two relevant considerations are:

- Did the service provider have an incentive to agree to non-arm's length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

In the absence of an incentive to agree to non-arm's length terms, the AER considered it is reasonable to presume the contract price reflects efficient costs. This presumption is also reasonable where an incentive to agree to non-arm's length terms exists, however the contract was subject to a competitive open tender process in a competitive market.

The alternative assessment framework proposed by CitiPower and Powercor in their revised regulatory proposals adopted the AER's presumption threshold without modification. SP AusNet did not agree with the presumption threshold where the service provider had minority shareholders who did not have an ownership stake in the related party contractors. JEN and United Energy did not comment on the presumption threshold.

The AER has maintained the presumption threshold from its draft decision. Applying this threshold to the Victorian DNSPs outsourcing arrangements has led to the same arrangements passing and not passing this threshold as set out in the draft decision.

The AER identified some limited concerns with the tendering processes conducted by United Energy in its appointment of its 'turn key service provider' to replace Jemena Asset Management. However, the AER still considered that this arrangement passed the presumption threshold and so the AER can presume these arrangements reflect efficient costs that would be incurred by a prudent operator. The AER also considered it was reasonable to presume SP AusNet's arrangement with Tenix Alliance reflects efficient and prudent costs. Both these arrangements are with parties who are not related to the service provider. However, each of the Victorian DNSPs' related party arrangements did not pass the presumption threshold.

In the draft decision, where an arrangement 'passes' the presumption threshold (stage 2A), the AER considered the starting point for setting future expenditure allowances should be the contract price itself, with limited further examination required. This further examination involves checking whether the contract wholly relates to the relevant services (for example, standard control services) and whether the (efficient) contract price already compensates for risks or costs provided for elsewhere in the building blocks.

The AER has maintained the stage 2A assessment from its draft decision.

In the draft decision, where a contract did not pass the presumption threshold (stage 2B), the AER considered the starting point for setting future expenditure allowances should be the contractor's actual direct costs, with a 'margin' above this level permitted only where the service provider is able to establish the efficiency and prudency of such a margin against legitimate economic reasons for the inclusion of the margin (and its quantum).

The reasons the AER considered legitimate for the inclusion of a margin were:

- to compensate for a share of the contractor's corporate and other indirect costs
- to provide a return on and return of assets owned and utilised by the contractor, but only where those assets are not already contained in the service provider's regulatory asset base (RAB)
- to compensate for asymmetric risks faced by the contractor, but only where the service provider's proposed self insurance allowance has been reduced commensurately with the risks passed on to the contractor that it no longer faces, and
- to retain the benefit of historical efficiencies for a period of time.

The AER maintains its position on these reasons in this final decision.

As the AER's assessment has already factored in a share of the related party's corporate costs into the expenditure forecasts, no additional 'margin' was required to compensate.

While each of the Victorian DNSPs have related party transactions, only CitiPower, Powercor and JEN have related party transactions that include margins in excess of overheads that the respective DNSPs included within their opex and capex forecasts.

Accordingly, the AER has scrutinised CitiPower's, Powercor's and JEN's related party contracts that did not pass the presumption threshold.

In the draft decision, the AER was not aware of the existence of any assets owned and utilised by related party contractors that were not already contained within the Victorian DNSPs' RABs. Additionally, the Victorian DNSPs proposed self insurance allowances related to the risks faced on their network and had not been adjusted to reflect risks passed on to their contractors through their pricing arrangements. Therefore the inclusion of a margin had not been substantiated against these reasons.

CitiPower and Powercor have not identified any assets used by their related party contractors not already contained within their RABs. JEN has confirmed that its related party contractors utilise no significant assets in the provision of services to it. Additionally, the basis of CitiPower's, Powercor's and JEN's self insurance allowances in their revised proposals were as per the basis from their initial proposals. Accordingly, consistent with the draft decision, the efficiency and prudency of including a margin has not been substantiated against these reasons.

Finally, in the draft decision, as the AER sought to reward the Victorian DNSPs for the historical efficiencies realised by their related parties through the efficiency carryover mechanism (ECM) allowance, no margin was required for this reason. In this context, the AER did not consider outsourcing arrangements should be assessed against a 'standalone, in-house' cost standard. The Victorian DNSPs' related parties had achieved substantial economies of scale and scope from operating multiple networks. However the AER did not consider it was appropriate under the NER for these benefits to be retained indefinitely by the service provider's and related parties' shareholders. Rather, consistent with the treatment of other efficiencies under the regulatory regime, the AER considered the benefit of operating efficiencies should be retained for six years and the benefit of capital efficiencies retained until the end of the regulatory control period in which they are realised.

SP AusNet supported the AER's assessment approach of contracts that do not pass the presumption threshold. JEN also supported the AER's legitimate economic reasons in respect of corporate overheads, assets used by the contractor and asymmetric risk.

However, CitiPower, Powercor and JEN did not agree with the AER's rejection of a 'standalone, in-house' cost standard by which to assess contract prices. The DNSPs have put forward legal and economic reasons to support this standard, including referencing the Tribunal's support for a 'standalone' operator benchmark in Re Optus Mobile Pty Limited & Optus Networks Pty Limited [2006] ACompT 8 (22 November 2006).

Essentially, CitiPower, Powercor and JEN considered it would still be an efficient outcome for their related party contractors to retain the benefit of historical efficiencies indefinitely. Alternatively if these were to be shared with the DNSPs and ultimately consumers, it was an efficient and prudent outcome for this timing to be at the discretion of the related parties.

CitiPower, Powercor and JEN also argued the AER's approach creates a perverse incentive for DNSPs to internalise activities that are currently outsourced, even where outsourcing is the more efficient option.

The AER has viewed each of the reasons put forward by CitiPower, Powercor and JEN in support of a standalone, in-house cost standard. The AER's position on these reasons is summarised in the following paragraphs.

Contrary to the view of CitiPower, Powercor and JEN, the AEMC's rule determination on chapter 6A does not suggest the AEMC intended the prudency criterion component 'in the circumstances' of the relevant DNSP to be restricted to the network operating circumstances or network characteristics of the relevant DNSP. The AER considers that the term 'circumstances' should be given its ordinary meaning which includes both the network operating circumstances and corporate structure and ownership circumstances of the relevant DNSP.

The actions of each of the Victorian DNSPs to outsource significant activities to centralised, specialist operators within their corporate structures appears consistent good business practice. This is primarily because of the significant economies of scale and scope that each of these operators can achieve through operating multiple networks. The fact that significant economies of scale and scope have been achieved is not in dispute.

Accordingly, the AER's concerns are not over the Victorian DNSPs' corporate structures, per se, but rather over the pricing arrangements agreed to by the Victorian DNSPs and these related party contractors. Specifically, whether these pricing arrangements reflect efficient costs and costs that a prudent operator in each of the Victorian DNSPs' circumstances would incur.

The AER expects that a prudent operator would not agree to continue to pay a contractor standalone, in-house costs (the costs it incurred pre-outsourcing), and would only agree to pay something less than this amount as it would require that it receives a share of the contractor's economies of scale and scope (which it has helped the contractor achieve by virtue of outsourcing its activities to the contractor).

Consequently, the AER considers that the prudency criterion provides guidance that the appropriate cost standard is some amount less than 'standalone, in-house' costs, and that the efficiency criterion provides more precise guidance for how much less than the standalone, in-house costs is appropriate.

It’s accepted by CitiPower, Powercor and JEN that the expected pricing outcomes from a workably competitive market is an appropriate framework to consider the meaning of efficient costs. There is also general acceptance that in a workably competitive market a contractor cannot continue to earn a margin above its full economic costs (that is, earn abnormal profits) for efficiencies it has realised in the past. The issue in contention is over what time period this pass back of historical efficiencies to consumers would be expected to occur in a workably competitive market.

The AER has adopted a retention period of six years for operating efficiencies and until the end of the regulatory control period for capital efficiencies. This is consistent with the regulatory framework set up by the AEMC for the treatment of efficiencies. And in setting up this framework the AEMC acknowledged that the fundamental goal of incentive regulation was to replicate a workably competitive market. The AEMC also stated that in a competitive market historical efficiencies are eventually passed through to consumers.

The AER has reviewed the margin benchmarking submitted by CitiPower, Powercor and JEN. The AER notes that this margin benchmarking does not suggest a particular retention period. The AER also noted three studies referred to by the QCA is setting up its efficiency carryover mechanism which suggest that in commercial reality firms do not retain the benefit of efficiencies for longer than five years. Based on these factors, the AER considers that its proposed retention periods are a reasonable approximation of observed commercial practice.

The AER has also reviewed the ATO guidelines material submitted by CitiPower and Powercor, but considers that the different objectives of the tax and economic regulatory regimes means that related party transactions made under the ATO guidelines should not be assumed to automatically also meet the NER requirements.

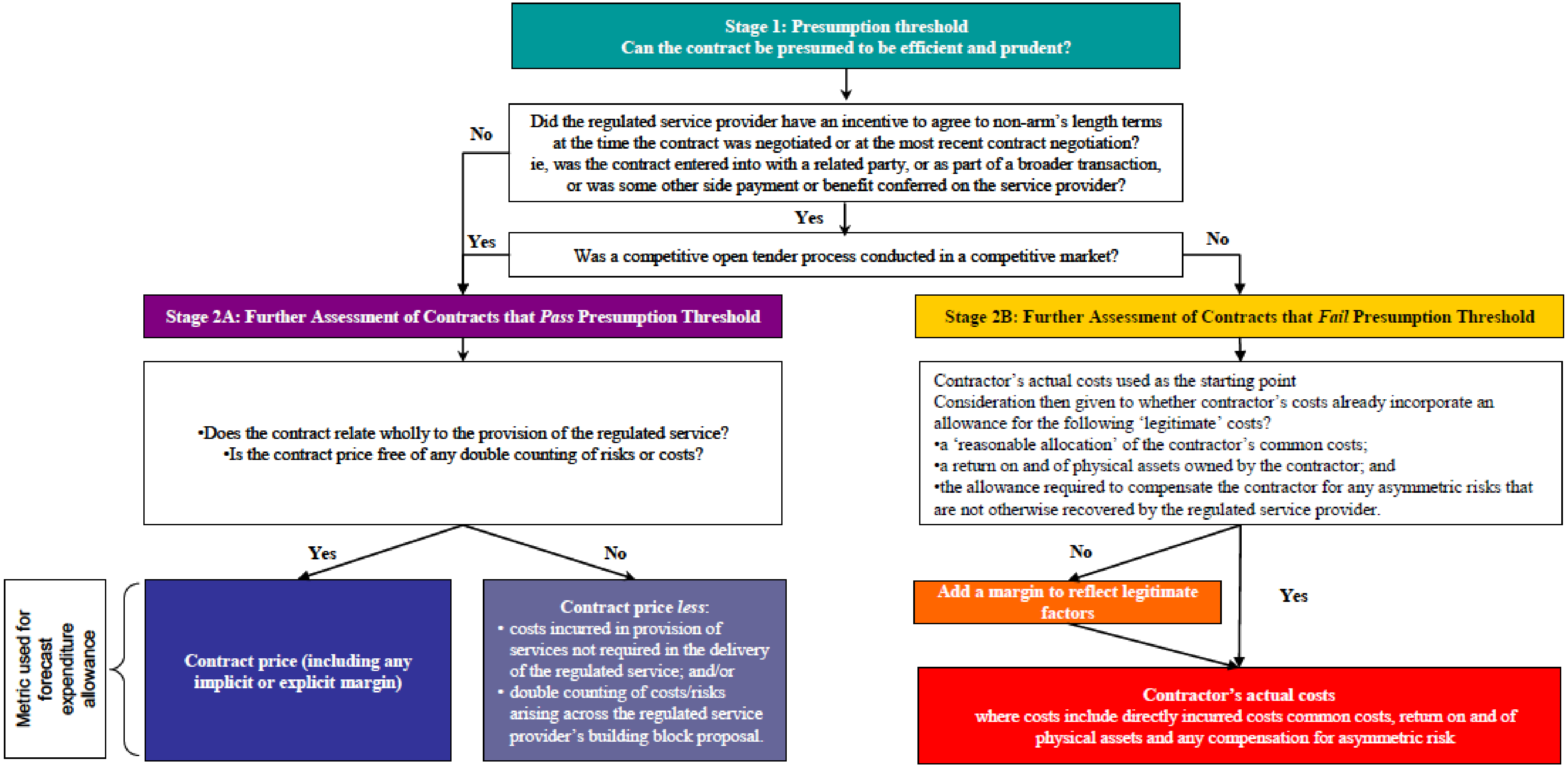
Accordingly, while the AER has had regard to the margin benchmarking and ATO material it has not persuaded the AER to depart from the retention periods which are consistent with the treatment of efficiencies realised by DNSPs themselves. The AER considers consistency between the treatment of efficiencies realised by related parties and the DNSPs themselves to be an important consideration. The AER considers these retention periods are consistent with the expected pricing outcomes from a workably competitive market.

The interaction with the EBSS is also important. The AER's approach results in historical operating efficiencies being rewarded through the EBSS. This approach is appropriate because the AER can not reasonably assume that the DNSPs and their related parties will pass back efficiencies to consumers in an appropriate timeframe. The AER also notes that it considers the initial division of the benefit from historical efficiencies between the DNSP and its related party is a matter entirely up for them to decide. The AER is concerned about when consumers share in these benefits, not the dividing up of the benefit between the DNSP and related party before it is passed back to consumers.

Finally, the AER considers the adoption of a standalone cost standard is not consistent with the NEO as while it would promote efficiencies, it would not promote efficiencies in the long term interests of consumers as consumers would not share in these efficiencies. The AER's retention periods ensure DNSPs and related party contractors are provided with effective incentives—in accordance with the relevant revenue and pricing principle—to pursue efficiencies (because they get to keep the benefit for a period of time) while also promoting the NEO because consumers share in the benefit of the efficiencies after a period of time.

The AER's approach to assessing outsourcing arrangements is summarised in Figure 6.10.

Figure 6.10 AER—Final decision approach to outsourcing and related party transactions



Source: AER analysis

7 Operating and maintenance expenditure

This chapter sets out the AER's conclusions on forecast operating and maintenance expenditure (opex) allowances for the Victorian DNSPs for the forthcoming regulatory control period. It also:

- summarises the AER's draft decision opex allowances for the Victorian DNSPs
- provides a general overview of the revised regulatory proposals
- addresses comments made by stakeholders on the revised regulatory proposals
- summarises the AER's main considerations and responses to stakeholder comments
- discusses the framework the AER has applied in assessing each proposal against the requirements set out at clause 6.5.6 of the National Electricity Rules (NER)
- sets out the AER's reasons why it does not accept the Victorian DNSPs' revised forecast opex proposals
- sets out the estimate of the total of each Victorian DNSP's required opex for the forthcoming regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

This estimate and the AER's conclusions are set out in section 7.6 of this chapter.

7.1 Regulatory requirements

The AER must assess the total of the forecast operating expenditure included in each DNSP's building block proposal for the forthcoming regulatory control period. Clause 6.5.6(c) of the NER states that the AER must accept the forecast of required operating expenditure of a DNSP that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the forthcoming regulatory control period reasonably reflects:[1]

> (1) the efficient costs of achieving the operating expenditure objectives; and
>
> (2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The opex objectives are contained in clause 6.5.6(a) of the NER. A DNSP is required by clause 6.5.6(a) of the NER to include in its building block proposal the total forecast opex for the regulatory control period that the DNSP considers is required to:

1 NER, cl. 6.5.6(c).

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) maintain the quality, reliability and security of supply of standard control services; and

(4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In deciding whether or not the AER is satisfied that the total opex forecast reasonably reflects the opex criteria, the AER must have regard to the opex factors in clause 6.5.6(e) of the NER. The opex factors the AER must have regard to are:[2]

(1) the information included in or accompanying the building block proposal;

(2) submissions received in the course of consulting on the building block proposal;

(3) any analysis undertaken by or for the AER and published before the distribution determination is made in its final form;

(4) benchmark opex that would be incurred by an efficient DNSP over the regulatory control period;

(5) the actual and expected opex of the DNSP during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between opex and capex;

(8) whether the total labour costs included in the capex and opex forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent to which the forecast of required opex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) the extent the DNSP has considered, and made provision for, efficient non-network alternatives.

If the AER is not satisfied that the total opex forecast reasonably reflects the opex criteria, the AER must not accept the opex forecast.[3] If the AER does not accept a forecast opex proposal in accordance with clause 6.5.6(d), clause 6.12.1(4)(ii) of the NER states that:

> The AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required operating expenditure for the regulatory control period that the AER is satisfied

[2] NER, cl. 6.5.6(e).
[3] NER, cl. 6.5.6(d).

> reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors.

Under clause 6.12.3(f)(2) of the NER, this estimate must be the minimum adjustment to the proposed forecast opex necessary to comply with the NER. The AER’s approach to opex assessment is discussed further in section 7.5.1.

7.2 AER draft decision

In the draft decision, the AER considered that, with the exception of outcomes following the Victorian Bushfire Royal Commission (VBRC), the Victorian DNSPs would not be subject to numerous new regulatory or legislative obligations, or changes to their operating environments such that expenditure over the forthcoming regulatory control period would be materially affected. The AER rejected many of the Victorian DNSPs' step change proposals ($293 million proposed, $44 million accepted) which included additional costs due to, among other things, climate change, insurance and regulatory matters. The AER considered that some new regulatory compliance costs should be borne by the DNSPs, including with respect to electrical safety, network planning and customer communications.

The AER allowed opex for the impact of growth (scale escalation), including expected productivity improvements, and allowed the value of the Victorian DNSPs’ opex allowance to be maintained in real terms (incorporating changes in real input costs for labour and materials).

The AER did not accept the Victorian DNSPs’ forecast opex proposals for the forthcoming regulatory control period. The AER was not satisfied that the total of each DNSP’s forecast opex reasonably reflected the opex criteria in clause 6.5.6(c) of the NER. The AER substituted its own opex forecast for each DNSP, in accordance with clause 6.12.1(4)(ii) of the NER.

The AER draft decision opex allowance for the forthcoming regulatory control period was $2 190 million ($2010), which represented a reduction of $763 million (26 per cent) from the Victorian DNSPs’ initial regulatory proposals, and broadly aligned with the Victorian DNSPs' expected underspend for the current regulatory control period.

The AER’s draft decision allowance of $2 190 million ($2010) represented an increase of $49.0 million, or 2 per cent, above the Victorian DNSPs’ initial estimated actual opex in the current regulatory control period of $2 141 million. The AER's draft decision allowance is displayed in Table 7.1, and Figure 7.1 which compares the draft decision allowance to the DNSPs’ initial proposals, prior allowances and forecasts.

Figure 7.1 AER draft decision opex comparison

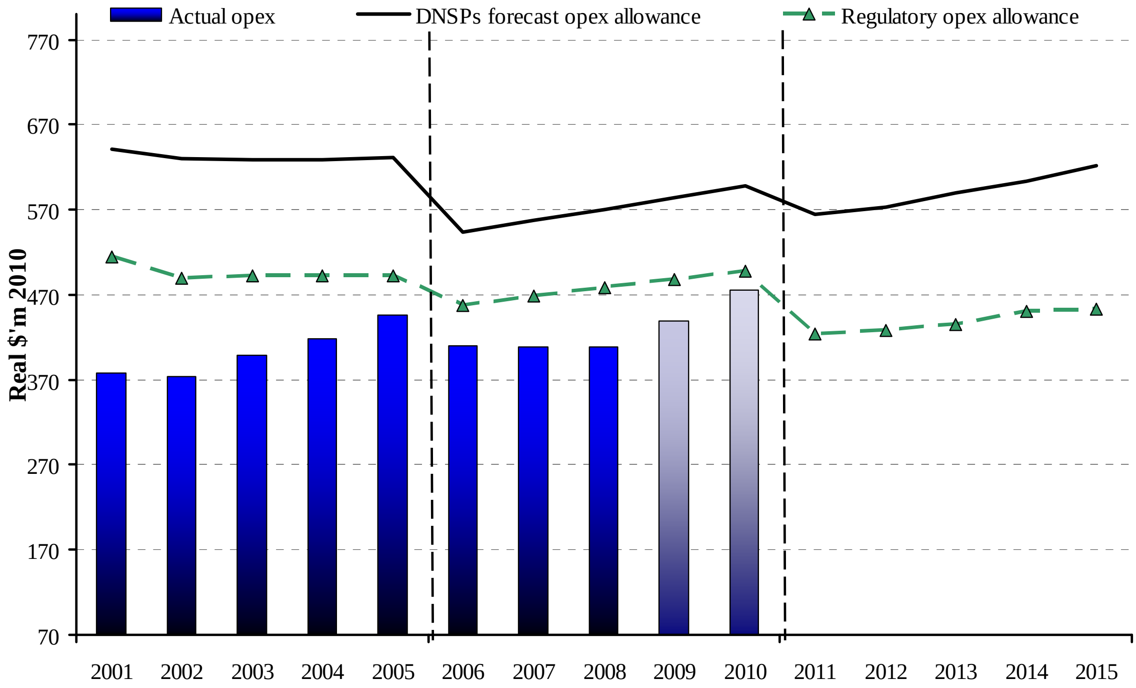


Table 7.1 AER draft decision opex allowance for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
DNSP proposed opex	**244.0**	**902.2**	**319.4**	**885.7**	**601.8**	**2 953.2**
AER opex build-up						
AER base year costs	164.5	578.3	220.0	588.2	424.8	1975.7
AER scale escalation	1.4	8.8	2.5	8.4	4.6	25.8
AER real cost escalation	7.6	28.1	9.5	19.5	17.6	82.4
AER step changes	6.0	–8.1	10.7	25.0	10.9	44.5
AER debt raising costs	3.8	6.3	2.2	6.0	4.0	22.2
AER self insurance	–	–	0.5	–	0.1	0.6
AER other[a]	1.1	8.9	1.1	24.7	3.3	39.1
AER total opex	**184.4**	**622.3**	**246.5**	**671.8**	**465.3**	**2 190.3**
Adjustment	**–59.6**	**–280.0**	**–72.9**	**–213.9**	**–136.5**	**–762.9**
Adjustment (per cent)	**–24.4**	**–31.0**	**–22.8**	**–24.2**	**–22.7**	**–25.8**

Source: AER, *Draft decision*, p. 274.
[a]DMIS, GSL

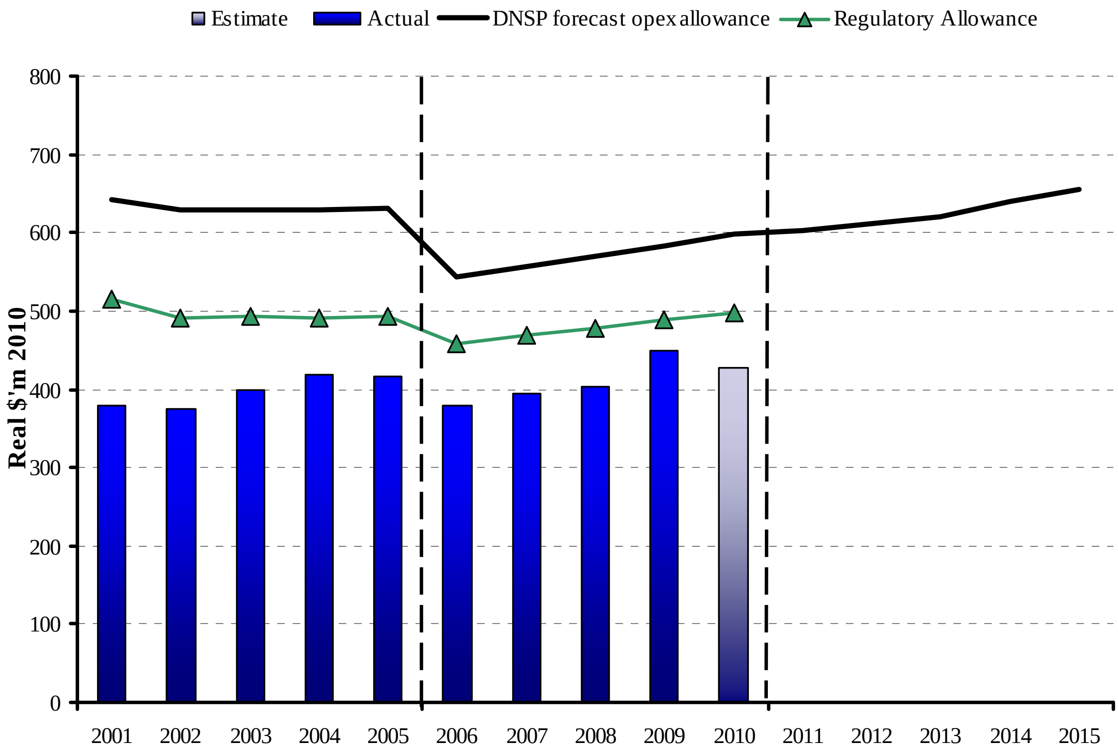
7.3 Victorian DNSP revised regulatory proposals

7.3.1 Current period outcomes

This section compares the actual opex spent by the Victorian DNSPs with the allowances set by the Essential Services Commission of Victoria (ESCV) and the Victorian DNSPs' regulatory proposals.

Figure 7.2 shows the Victorian DNSPs' actual and allowed total opex in the current and previous regulatory control periods, and their proposed forecast opex for the forthcoming regulatory control period.

Figure 7.2 Victorian DNSP current regulatory control period opex comparison ($'m 2010)



Note: Actual figures are adjusted actuals as used in ECM calculation.

The aggregate of the Victorian DNSPs' actual opex for the current and previous regulatory periods is represented by the blue bars in Figure 7.2. The lightly shaded bar represents the estimated spend for 2010. The Victorian DNSPs' current underspend relative to the ESCV regulatory opex allowance is denoted by the difference between the bars and the green patterned line. The Victorian DNSPs' underspend relative to their own proposals is the difference between the bars and the solid line. The analysis indicates that the aggregate of the Victorian DNSPs' forecast levels of efficient opex exceed audited actual opex by a margin of between 30 per cent and 69 per cent for the current and previous regulatory control periods.

The analysis also confirms that the Victorian DNSPs' actual costs generally sit below the approved efficient regulatory opex allowance. The Victorian DNSPs, during the current and previous regulatory control periods, have demonstrated they continually outperform their opex regulatory benchmarks.

The ongoing incentive for the Victorian DNSPs to reduce costs reveals an efficient starting point for the AER's assessment of forecast opex (see section 7.5.1 for a discussion on the AER's approach to assessment).

7.3.2 Revised regulatory proposals

The Victorian DNSPs' revised total forecast opex for the forthcoming regulatory control period (Table 7.2) is $3 131 million, which represents an increase of $940 million (43 per cent) from the $2 190 million approved in the draft decision, and $1 076 million (52 per cent) increase from revised expected actual opex in the current regulatory control period of $2 055 million. Table 7.3 to Table 7.7 set out each Victorian DNSP's revised forecast opex build up for the forthcoming regulatory control period.

Table 7.2 Victorian DNSP revised proposal opex allowance for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
DNSP opex build-up[a]						
Base year costs[b]	201.2	684.3	262.6	613.0	550.1	2311.3
Scale escalation	6.7	28.7	8.4	20.7	–	64.6
Real cost escalation	14.3	58.0	21.2	34.0	–	127.5
Step changes	32.4	136.8	46.0	285.8	83.1	584.0
Debt raising costs	11.0	18.8	2.6	6.5	4.3	43.3
DNSP total opex	**265.7**	**926.6**	**340.8**	**960.1**	**637.5**	**3130.7**

Source: Victorian DNSP revised RINs, revised PTRMs.
[a]Excludes DMIA allowance.
[b]Includes related party margins.

Table 7.3 CitiPower revised proposed opex for 2011–2015 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
DNSP opex build-up[a]						
Base year costs	37.1	37.1	37.1	37.1	37.1	185.7
Scale escalation	0.4	0.8	1.3	1.8	2.4	6.7
Real cost escalation	1.0	2.2	3.1	3.6	4.4	14.3
Step changes	8.1	6.6	6.6	5.2	6.0	32.4
Related party margins	2.9	3.0	3.1	3.2	3.4	15.5
Debt raising costs	1.9	2.0	2.2	2.4	2.6	11.0
CitiPower total opex	**51.3**	**51.7**	**53.4**	**53.4**	**55.8**	**265.7**

Source: CitiPower revised RIN, revised PTRM.
[a]Excludes DMIA allowance.

CitiPower's total revised forecast opex for the forthcoming regulatory control period is $265.7 million, which represents an increase of $81.3 million (44 per cent) from the AER's draft decision allowance of $184.4 million, and an increase of $99.5 million (60 per cent) from CitiPower’s revised current period estimate of $166.1 million.

Table 7.4 Powercor revised proposed opex for 2011–2015 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
DNSP opex build-up[a]						
Base year costs	129.6	129.6	129.6	129.6	129.6	648.2
Scale escalation	1.5	3.6	5.6	7.8	10.2	28.7
Real cost escalation	4.0	8.6	12.2	15.2	18.1	58.0
Step changes	30.7	28.5	24.2	26.1	27.2	136.8
Related party margins	6.6	6.9	7.2	7.5	7.8	36.1
Debt raising costs	3.2	3.5	3.8	4.0	4.3	18.8
Powercor total opex	**175.6**	**180.8**	**182.6**	**190.3**	**197.3**	**926.6**

Source: Powercor revised RIN, revised PTRM.
[a]Excludes DMIA allowance.

Powercor's total revised forecast opex for the forthcoming regulatory control period is $926.6 million, which represents an increase of $304.3 million (49 per cent) from the AER's draft decision allowance of $622.3 million, and an increase of $307.6 million (50 per cent) from Powercor’s revised current period estimate of $619.0 million.

Table 7.5 JEN revised proposed opex for 2011–2015 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
DNSP opex build-up[a]						
Base year costs[b]	52.5	52.4	52.5	52.6	52.7	262.6
Scale escalation	0.6	1.2	1.7	2.2	2.8	8.4
Real cost escalation	2.6	3.4	4.3	5.1	5.8	21.2
Step changes	10.0	7.6	6.5	10.3	11.7	46.0
Debt raising costs	0.4	0.5	0.5	0.6	0.6	2.6
JEN total opex	**66.1**	**65.1**	**65.5**	**70.7**	**73.5**	**340.8**

Source: JEN revised RIN, revised PTRM.
[a]Excludes DMIA allowance.
[b]Includes related party margins.

JEN's total revised forecast opex for the forthcoming regulatory control period is $340.8 million, which represents an increase of $94.3 million (38 per cent) from the AER's draft decision allowance of $246.5 million, and an increase of $87.7 million (35 per cent) from JEN's revised current period estimate of $253.1 million.

Table 7.6 SP AusNet revised proposed opex for 2011–2015 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
DNSP opex build-up[a]						
Base year costs	122.6	122.6	122.6	122.6	122.6	613.0
Scale escalation	1.3	2.7	4.1	5.5	7.0	20.7
Real cost escalation	1.4	3.4	6.6	9.8	12.8	34.0
Step changes	51.5	55.7	58.4	59.9	60.3	285.8
Debt raising costs	1.1	1.2	1.3	1.4	1.5	6.5
SP AusNet total opex	**177.9**	**185.6**	**193.0**	**199.3**	**204.2**	**960.1**

Source: SP AusNet revised RIN, revised PTRM.
[a]Excludes DMIA allowance and S-factor true-up costs.

SP AusNet's total revised forecast opex for the forthcoming regulatory control period is $960.1 million, which represents an increase of $288.3 million (43 per cent) from the AER's draft decision allowance of $671.8 million, and an increase of $365.4 million (61 per cent) from SP AusNet's revised current period estimate of $594.7 million.

Table 7.7 United Energy revised proposed opex for 2011–2015 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
DNSP opex build-up[a]						
Controllable opex (exc step changes)	114.3	110.3	109.1	108.4	108.0	550.1
Step changes	16.9	17.2	16.3	16.3	16.3	83.1
Debt raising costs	0.8	0.8	0.9	0.9	1.0	4.3
United Energy total opex	**131.9**	**128.3**	**126.3**	**125.7**	**125.3**	**637.5**

Source: United Energy revised PTRM.
[a]Excludes DMIA allowance.

United Energy's total revised forecast opex for the forthcoming regulatory control period is $637.5 million, which represents an increase of $172.2 million (37 per cent) from the AER's draft decision allowance of $465.3 million, and an increase of $215.2 million (51 per cent) from SP AusNet's revised current period estimate of $422.3 million.

7.4 Consultant review

The AER engaged Nuttall Consulting to assist the AER in its review of several step changes, and also to review aspects of the AER’s approach to scale escalation. This is discussed in more detail in sections 7.5.4 and 7.5.6. The AER also engaged Access Economics in relation to labour forecasts. This is discussed in section 7.5.5.

7.5 Issues and AER considerations

7.5.1 AER's approach to opex assessment

7.5.1.1 Framework

The Victorian DNSPs' revised regulatory proposals, and submissions received in response to the AER's draft decision raised issues in relation to the AER's approach to assessing operating expenditure. For this reason, the AER considers it pertinent, as part of this final decision, to outline its approach to assessing the Victorian DNSPs' proposed forecast opex under clause 6.5.6 of the NER.

The AER’s decision requires it to be satisfied that the total of the forecast opex, not each individual program and project or element which constitutes that total forecast opex, reasonably reflects the operating expenditure criteria. The operating expenditure criteria are set out at clause 6.5.6 (c) of the NER, and state:

> The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects:
>
> 1) the efficient costs of achieving the operating expenditure objectives; and

> 2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and
>
> 3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Read together, the AER considers the three operating expenditure criteria are complementary and are designed to identify the level of efficient costs a prudent operator, in the actual circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the operating expenditure objectives. The AER considers the level of efficient costs referred to here are those expected costs that would be based on the outcomes in a workably competitive market.

Contrary to the AER's view above, some submissions have posited that there is an internal tension between the operating expenditure criteria and that the reference to 'efficient costs' in clause 6.5.6(c)(1) competes with and is not complementary to the reference to 'prudent operator' in clause 6.5.6(c)(2).[4] The corollary of this submission is that a prudent operator, who balances risk, would incur a premium above what is otherwise the efficient level of costs.

The AER does not consider that this is an appropriate interpretation of the operating expenditure criteria, having regard to the regulatory framework for distribution services under Chapter 6 of the NER, and the NEO. This is because the opex criteria operate together to control or limit the amount of forecast expenditure that a DNSP would face if exposed to a competitive market. In particular, the AER considers that a DNSP's forecast opex must be based only on the costs that:

- would be incurred in a workably competitive market so that the costs reflect the efficient costs of achieving the opex objectives (clause 6.5.6(c)(1))
- these costs must only include activities or actions by the DNSP that would be incurred by a prudent operator in the circumstances of the DNSP to achieve the opex objectives (clause 6.5.6(c)(2)) and
- reflect a realistic expectation of the demand forecast and costs inputs required to achieve the opex objectives (clause 6.5.6(c)(3)).

The AER considers that this interpretation promotes the long term interests of customers consistent with the NEO, where the DNSP will only pass on to customers those costs which are efficient and are necessary or reflect good industry practice, to provide standard control services.

AER approach to operating expenditure assessment

In deciding whether a forecast operating expenditure allowance reasonably reflects the operating expenditure criteria, the AER has:

- considered the revised regulatory proposals provided by the Victorian DNSPs, taking into account submissions received

4 CitiPower, *Revised regulatory proposal*, p. 511; Powercor, *Revised regulatory proposal*, p. 517.

- done so in a manner that will or is likely to contribute to the national electricity objective, which is set out at section 7 of the NEL.

- taken into account the revenue and pricing principles set out at section 7A of the NEL.

- taken into account the operating expenditure factors, criteria and objectives set out at clause 6.5.6 of the NER.

The national electricity objective

The NEO is contained in section 7 of the NEL:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Characterising the operating expenditure criteria as complementary requires the AER to identify the level of efficient costs, and by identifying that level of efficient costs, the AER is promoting efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers with respect to the price of electricity. The AER considers that this interpretation of clause 6.5.6 promotes the achievement of the NEO.

Where costs are efficient, it necessarily follows that prices for services are also efficient. Therefore, in providing the DNSPs with a total forecast opex allowance that reasonably reflects the efficient costs of maintaining the quality, safety and reliability of supply of the network, the AER is meeting both limbs of the NEO.

The revenue and pricing principles

In assessing total forecast opex the AER also takes into account the revenue and pricing principles (RPP). The revenue and pricing principles relevant to the assessment of total forecast opex are:[5]

> (2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.
>
> (3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes-

5 NEL, s. 7A.

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

By placing emphasis on the 'revealed cost approach', the AER is providing the Victorian DNSPs with a 'reasonable opportunity' to recover at least their efficient costs, as required by section 7A(2) of the NEL. As discussed below, the AER has adopted a revealed cost approach which includes assessing and estimating a base year amount, together with a 'scale escalation' allowance, a 'real cost escalation' allowance and a 'step change' allowance. This approach, which is consistent with the requirements of clause 6.5.6 of the NER, provides a DNSP with a 'reasonable opportunity' to recover at least its efficient costs because the efficient historical costs of operating the network are captured in the base year, and material changes to a DNSP's operating environment are captured by:

- expected costs related to network growth
- expected input cost changes and
- step changes.

The AER's approach also ensures that the Victorian DNSPs are provided with effective incentives in order to promote economic efficiency with respect to investment in, and use of, a distribution system.[6] Specifically, service providers are provided with incentives to realise operating expenditure efficiencies within the regulatory control period (and therefore, in the efficient provision of services and operation of the network). Incentives to seek cost efficiencies are also provided through the operation the EBSS and the STPIS (to ensure that cost efficiencies are not at the expense of service quality and network performance).

In identifying that level of efficient costs the AER has also had regard to the economic costs and risks of the potential for under and over investment, and the under and over utilisation of the Victorian DNSPs' distribution systems. The AER considers the efficient level of costs it is required to identify leads to efficient prices and maintains the safety, quality and reliability of the distribution network.

Operating expenditure factors

Clause 6.5.6 of the NER does not require that all operating expenditure factors be taken into account in reviewing each element that may constitute a total forecast operating expenditure allowance. In practice, in assessing a particular element of total forecast opex, the AER has only had regard to the opex factors it considers relevant to that element. However, from the combined assessment of each opex element, it follows that the AER has had regard to all opex factors in its assessment of total forecast opex.

6 NEL, Section 7A(3).

The following discussion briefly outlines the opex factors the AER has had regard to for each element of the Victorian DNSPs' proposed forecast opex. Further details on this assessment can be found in appendices J, K, L, M and N of this final decision.

Revealed cost approach of calculating base opex

The AER considers that given the incentives to minimise costs in the regulatory regime, the revealed costs of a DNSP are likely to be a reasonable approximation of efficient costs in the circumstances of that DNSP for the scope of work undertaken. Further, by testing the historical volumes of activity undertaken with past forecasts, the AER can and does infer whether or not the forecasting processes employed by a DNSP can reasonably reflect an estimate of future needs. This is consistent with clauses 6.5.6(a)(3) and (4), 6.5.6(c)(1) and (2), and 6.5.6(e)(1) and (5) of the NER. The AER also considers that benchmarking analysis is a useful tool in assessing whether the revealed costs of a DNSP are efficient and prudent.

The use of a base year (or revealed cost) approach is an accepted regulatory practice which has been implicitly accepted by the Victorian DNSPs (with the exception of United Energy). This approach has been the basis for the initial and revised operating expenditure proposals of the Victorian DNSPs. This is further noted by the Australian Energy Market Commission (AEMC), in its policy rationale underpinning the NER chapter 6A framework.[7] As part of developing that chapter, the AEMC stated:

> While informed opinions may differ on what are efficient costs, costs of a prudent operator or realistic expectation of forecast demand and input costs in the circumstances facing a regulated entity, those matters can be tested by reference to objective evidence drawn from history[8]
>
> …
>
> At the end of the period, the actual costs in this period may be used as a *basis* for establishing the reasonableness of the cost estimates provided by the TNSP in the subsequent regulatory control period.[9]

Scale and input cost escalators

The AER has applied scale escalation to the base year costs, in recognition of the potential costs associated with growth in the network in the forthcoming regulatory control period. However, the relative size of each distribution network is such that the Victorian DNSPs are able to realise economies of scale associated with operating and maintaining a larger network. The AER therefore adjusts the expected costs related to servicing a larger network to account for these efficiencies.[10]

In addition, over the regulatory control period, the costs incurred for labour and materials inputs may increase (or decrease) by an amount that is beyond the Consumer Price Index (CPI)—that is, the rate of inflation that is measured by CPI. Therefore, the AER provides compensation for these real increases (or decreases)

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7 Although chapter 6A applies to transmission, the AER considers that statements made by the AEMC on the incentive framework apply equally to distribution.

8 AEMC, *Rule determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006,* p. 53.

9 ibid., p. 93.

10 This is consistent with clauses 6.5.6(a)(1), (3) and (4), and 6.5.6(c)(3) of the NER.

through input cost escalation. For operating expenditure, this escalation is primarily for labour costs.[11]

Step changes

Step changes primarily provide an allowance for incremental costs arising from regulatory obligations, changes in the operating environment or where the base year opex allowance would not be sufficient for the DNSP to meet or manage the expected demand for standard control services, maintain the quality, reliability and security of supply, or maintain the reliability, safety and security of the distribution system.[12]

In its electricity distribution determination for NSW, the AER assessed proposed step changes against the NER and a set of criteria developed by its then consultants, Wilson Cook.[13]

The AER has since reconsidered its approach to assessing step changes and has decided not to apply the Wilson Cook criteria, as stated in the draft decision. Instead, in the draft decision and in this final decision, the AER has assessed step changes solely against the opex criteria and the opex factors in clause 6.5.6 of the NER, in a manner consistent with the NEO and which takes into account the RPP. The approach applied is that described above. The AER recognises that some of the Victorian DNSPs expressed concern with the AER not applying the Wilson Cook criteria. The AER also recognises that the Wilson Cook criteria were endorsed by the Australian Competition Tribunal (the Tribunal) in its review of EnergyAustralia's appeal against the AER's NSW distribution determination.[14] However, while the Tribunal has endorsed the Wilson Cook criteria, these criteria are not a substitute, and are solely additional to, the requirements of clause 6.5.6 of the NER. In reconsidering its assessment of step changes in the draft and this final decision, the AER considers that it is not necessary to go beyond the relevant requirements of the NEL and the NER, namely the opex criteria, the opex factors, the NEO and the RPP.

The AER also notes NERA's assessment of the AER's revealed cost approach to forecast opex, which was undertaken for SP AusNet. NERA raised concerns that the AER's approach to the assessment of opex step changes demonstrated a:

> … systematic unwillingness to contemplate prospective changes that have not arisen as a consequence of a change in a regulatory obligation or requirement.[15]

NERA considered that the AER had applied an 'overly narrow' interpretation of an opex step change and had not been consistent with its stated framework that a step

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11 Materials inputs costs are dealt with predominately in the capital expenditure allowance, which is consistent with clauses 6.5.6 (a)(3) and (4), and 6.5.6(c)(3) of the NER.

12 This is consistent with NER clauses 6.5.6(a), 6.5.6(c)(1) and (2) of the NER.

13 *Application by EnergyAustralia and Others* [2009] ACompT 8 (12 November 2009), [179] (Energy Australia)

14 JEN, *Revised regulatory proposal*, Appendix 7.2, p. 13, SP AusNet, *Revised regulatory proposal,* p. 205; United Energy; *Revised regulatory proposal*, p. 85.

15 NERA, *AER draft decision on opex and capex allowances: A report for SP AusNet,* 19 July 2010, p. 22.

change could arise from additional costs relating to 'new or removed regulatory obligations or requirements or changes in the operating environment'.[16]

The AER affirms the view it expressed in the draft decision that the efficient costs of a prudent DNSP include costs arising from new or removed regulatory obligations or requirements, or changes in the DNSP’s operating environment. It does not consider that step changes should be confined only to costs relating to changed regulatory obligations.

The AER has reviewed each of the step changes proposed by the Victorian DNSPs in their revised regulatory proposals and has considered changes in the DNSPs' operating environments as well as changed regulatory obligations. Step changes form one part of a total forecast opex that must reasonably reflect the opex criteria. The AER has assessed the proposed step changes against the relevant requirements of the NEL and the NER, namely the opex criteria, the opex factors, the NEO and the RPP.

Specific issues influencing opex assessment

Relative prices of and substitutability of capital and operating inputs

The relative prices of capital and operating inputs are considered in some detail by the AER and its advisers. Capital and operating costs estimates are examined by the AER's technical consultant, and the AER also obtains specialist advice on labour cost escalation (see appendix K). The AER has also continued its practice of separately reviewing the cost escalation of labour and materials and has incorporated the outcomes of those investigations into the analysis of the opex proposals.

Substitution possibilities between opex and capex can arise in many diverse ways. There are, for example, substitution possibilities between opex and capex in relation to reinforcement expenditure where opex in the form of network support or demand-side payments may defer or replace the need for a network augmentation. This consideration is closely aligned to the examination of whether efficient non-network alternatives have been adequately considered.

AMI

As noted in the draft decision, while it is too early to evaluate the precise effect on DNSP efficiency from the use of advanced metering infrastructure (AMI), the AER expects that such efficiencies will be evident over time and will impact on operating cost trends over time. Through its annual reporting framework, the AER will be monitoring the way AMI impacts on operating costs.

Climate change

In the draft decision, the AER did not approve any step change opex for the impact of climate change on the basis that costs associated with extreme weather events will be reflected in the Victorian DNSPs’ base year opex allowances.[17]

Only United Energy included in its revised regulatory proposal, step changes for changes to bushfire risk management, climate change studies and increased supply

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16 NERA, *AER draft decision on opex and capex allowances: A report for SP AusNet*, 19 July 2010, p. 20; AER, *Draft decision*, p. 224.

17 AER, *Draft decision*, Appendix L, p. 186.

restoration costs due to climate change.[18] For the reasons discussed in appendix L, the AER has not accepted United Energy's proposed step change for the impact of climate change.

Victorian Bushfire Royal Commission

The VBRC's recommendations were published on 31 July 2010 and include a range of measures in relation to electricity-caused fire and the regulatory obligations of DNSPs. As discussed in chapter 16, the AER considers that new legislative obligations arising from the VBRC will be pass through events, subject to the requirements of clause 6.6.1 of the NER.

7.5.2 United Energy's new business model and opex forecast

Unlike the other Victorian DNSPs, United Energy's opex forecast was not derived from a base, step and trend forecasting approach. The AER summarises its assessment of United Energy's opex forecast separately in this section. The AER's detailed assessment of United Energy's opex forecast is set out in appendix I.

United Energy’s current business model (as noted in the draft decision) is centred on:

- a small management structure that conducts strategic management and corporate governance activities both within and through services provided by its parent entity Diversified Utility Energy Trust (DUET)[19]
- a single outsourced contract (its operating services agreement (OSA)) under which the asset management, planning, construction and maintenance of its network is outsourced to Jemena Asset Management (JAM), which is ultimately owned by United Energy’s minority shareholder (Singapore Power).[20]

However, United Energy stated that the current OSA between United Energy and JAM expires on 31 July 2011 (six months into the forthcoming regulatory control period) and United Energy does not intend to renew this agreement. Rather, United Energy stated that it is in the process of transforming to a substantially different business model with much of the management, administrative and planning activities being internalised and performed by United Energy (or more precisely, by parties related to United Energy).

Accordingly, the first six months of United Energy's opex forecast in its regulatory proposal are based on its current business model, whereas the remainder of the forecast is based on expected costs under its new business model.

18 CitiPower, *Revised regulatory proposal*, p. 177; Powercor, *Revised regulatory proposal*, p. 167; JEN, *Revised regulatory proposal*, Appendix 7.2, confidential, p. 65; SP AusNet, *Revised regulatory proposal*, p. 234; United Energy, *Revised regulatory proposal*, pp. 88–91.

19 The AER understands that until recently, United Energy did not directly employ any staff. United Energy has until recently sourced only a limited number of management services from a related party—Pacific Indian Energy Services (PIES)—and certain management, investment and financial services from its majority shareholder DUET and a related party—AMP Capital Investors (AMPCI). PIES is jointly owned by United Energy, Multinet and Westnet Gas. United Energy, Multinet and Westnet Gas are both the owners and customers of PIES.

20 United Energy, Initial Regulatory proposal, p. xvii.

7.5.2.1 AER draft decision

United Energy's opex forecast was comprised of four components. The AER was satisfied that the unit costs associated with outsourced services were efficient and prudent and had been market tested through a reasonably competitive tender process. However, the AER was not satisfied the remaining three components of United Energy's forecast reflected efficient or prudent costs. Table 7.8 summarises the AER's draft decision assessment.

Table 7.8 AER draft decision — Assessment of different components of United Energy's opex forecast

Component of forecast	AER assessment
Outsourced services—unit costs	Units costs derived from reasonably competitive tender process. No significant concerns.
Outsourced services—unit volumes	Unit volumes estimated by UED. Not substantiated.
In-housed services—unit costs	Unit costs estimated by UED. Source material provided (through had not previously been referred to in regulatory proposal). No clear link between source material and forecast.
In-housed services—unit volumes	Unit volumes estimated by UED. Source material provided. Connection between source material and forecast not established.

Source: AER analysis

The AER substituted United Energy's opex forecast for an estimate derived from the AER's assessment of required opex derived from:

- a 'base year' opex derived mostly from the historical expenditure associated with operating United Energy's network under its current business model
- adjusted for scale, real cost escalation and step changes in the same manner as for the other Victorian DNSPs.[21]

7.5.2.2 United Energy revised regulatory proposal

In response to the draft decision, United Energy stated that: [22]

- The new business model necessitates a 'bottom up' forecasting approach, rather than a 'year 4' approach as adopted by the AER's draft decision. United Energy stated that a year 4 approach does not represent a valid forecast and as such United Energy would be breaching the Rules if it developed a forecast of its operating expenditure in that way.

21 AER, *Vic draft decision*, pp.235–36

22 United Energy, *Revised regulatory proposal*, pp.37-38.

- The AER's 'year 4' approach can be used to 'stress test' United Energy's forecasts for its new business model, similar to United Energy's reference line approach. However, the application of the AER's approach for United Energy contains a number of inappropriate adjustments and escalation factors.

- United Energy has provided a detailed explanation of the amendments that should be made to the AER's 'year 4' approach in order for it to provide a reasonable 'stress test' for United Energy's opex forecasts. This amended calculation illustrates that United Energy's original opex forecast for its new business model are reasonable and should be accepted by the AER.

- United Energy considers that the AER has established clear precedents by adopting opex forecasts in its NSW and Queensland determinations. The AER must consider the precedent that it has set in other jurisdictions when it examines the efficiency and prudency of United Energy's forecasts.

- United Energy has fully substantiated its opex forecast in accordance with the requirements of the Rules and in accordance with those requirements the AER must accept United Energy's forecast opex for the forthcoming regulatory control period.

United Energy also stated that it did not agree with the AER's draft decision to reject the remaining components—namely outsourced work volumes, in-house volumes and in-house unit costs.[23]

7.5.2.3 AER considerations and conclusion on United Energy's new business model forecast opex

The AER is not satisfied that United Energy's revised proposal based on its new business model total opex forecast reasonably reflects efficient, prudent and realistic costs. The AER has assessed the components of United Energy's opex forecast and has identified a number of issues. These issues predominantly relate to outsourced unit volumes which are significantly above historical levels without adequate justification, and management estimates of in-house costs which have not been properly substantiated by United Energy.

The AER's concerns over the robustness and reasonableness of United Energy's new business model forecast is furthered by the analysis in Figure 7.3 which demonstrates this forecast is significantly above the costs United Energy would be expected to incur under a continuation of its current business model.

United Energy has also submitted a counterfactual base opex forecast assuming a continuation of its current business model into the forthcoming regulatory control period. According to United Energy, this current business model counterfactual can be used to 'stress test' the reasonableness of its new business model forecast.

United Energy proposed a base opex amount of $106.3 million per annum for this counterfactual exercise. However, for the reasons set out in appendix I the AER found this was not a reasonable estimate and has substituted this amount for an estimate of

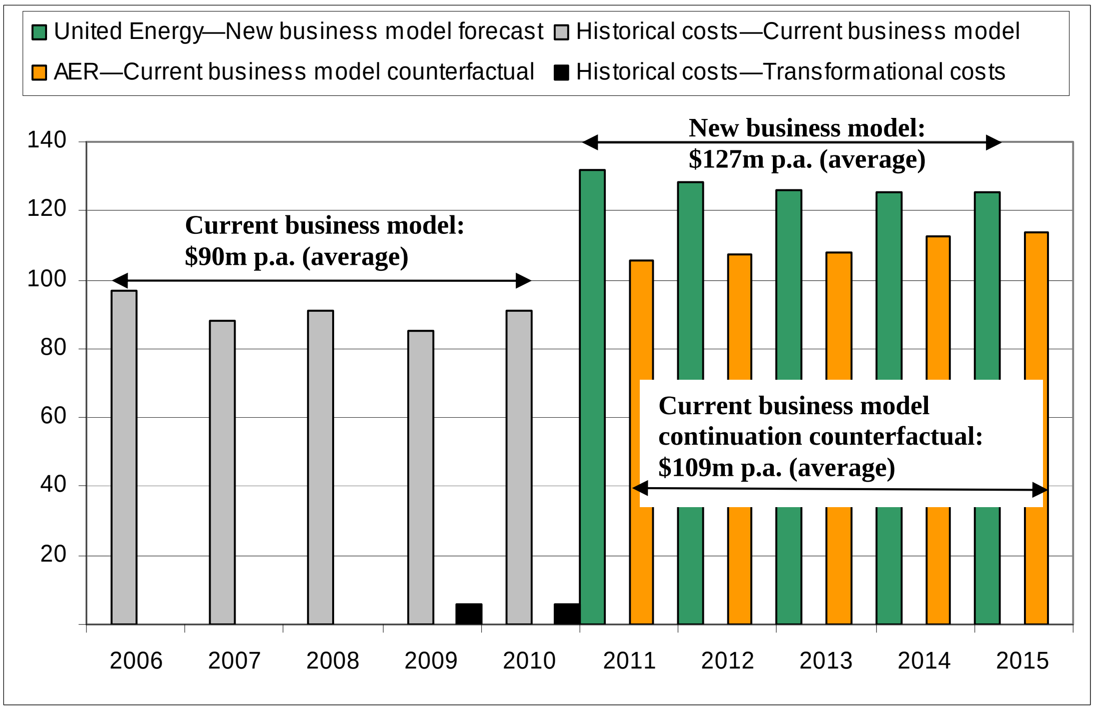
23 ibid.

$92.2 million. The AER notes that its base opex estimate is more in line with United Energy's historical opex (which was $91.2 million in 2009).

The most significant adjustments the AER made to United Energy's counterfactual base opex related to corporate costs. After having sought additional information from United Energy, United Energy had not substantiated the "UED / PIES" cost category. The AER substituted this with the "UEDH" costs (which includes the PIES costs) that was verifiable against United Energy's 2009 regulatory accounts.

The AER added to the $92.2 million per annum base opex forecast the step change, scale, cost escalation and self insurance amounts determined by the AER elsewhere in this decision. This resulted in an estimate of $109 million per annum, on average, if United Energy continued its current business model. This compares with the much higher amount of $127 million per annum, on average, which is United Energy's opex forecast under its new business model. This comparison is shown in Figure 7.3.

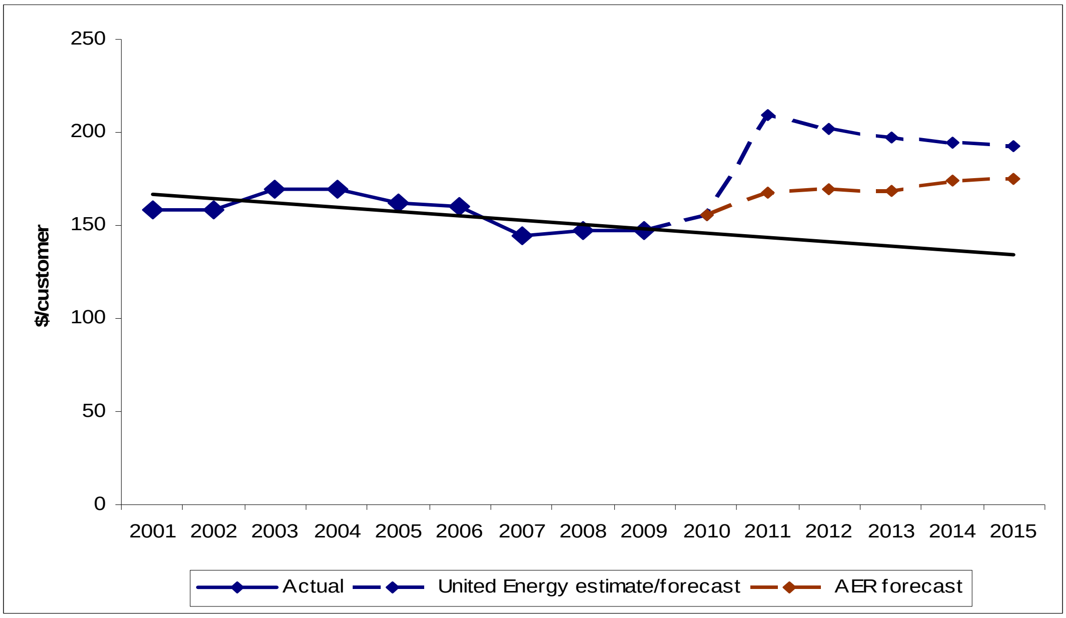
Figure 7.3 Total O&M—United Energy new business model forecast vs. AER current business model continuation counterfactual estimate O&M ($'m, 2010)



Source: United Energy revised proposal RIN template, revised PTRM, AER analysis.

United Energy's new business model also does not compare favourably against certain benchmarking analysis. For example, Figure 7.4 shows the ratio of United Energy's opex and customer numbers historically compared to its forecast.

Figure 7.4 United Energy opex per customer—Historical and forecast ($2010)



Source: AER analysis

Given these considerations, the AER is not satisfied that United Energy’s total opex forecast of $637.5 million reasonably reflects the efficient costs of a prudent operator in the circumstances of United Energy, and a realistic expectation of the demand forecast and costs inputs required to achieve the opex objectives.[24] The AER has adjusted United Energy's forecast to reflect the AER's current business model counterfactual estimate—a total of $547.5 million—which is the minimum adjustment the AER considers necessary to satisfy the clause 6.5.6(c) of the NER. This adjustment is shown in Table 7.9.

The AER's substituted forecast is a 15.0 per cent increase in United Energy’s total opex over the current regulatory period of $476.1 million.

Table 7.9 Final decision—United Energy operating and maintenance forecast (m, $2010)

	2011	2012	2013	2014	2015	Total
United Energy revised proposal	131.9	128.3	126.3	125.7	125.3	**637.5**
AER adjustment	–26.5	–20.7	–18.1	–13.3	–11.4	**–90.0**
AER final decision	105.4	107.6	108.2	112.4	113.9	**547.5**

Source: United Energy revised proposal PTRM, AER analysis.

The reason the AER has chosen to compare a current business model continuation counterfactual estimate against United Energy's new business model forecast, is because the AER considers, properly constructed, that this counterfactual reflects the efficient costs of a prudent operator in the circumstances of United Energy, and a realistic expectation of the demand forecast and costs inputs required to achieve the

24 NER, cll. 6.5.6(c), 6.5.6(a).

opex objectives.[25] If United Energy's new business model forecast had compared reasonably well against this estimate, then the AER would have accepted United Energy's forecast as reasonably reflecting the opex criteria. However, having made this comparison, and taking into account other relevant considerations, the AER is not satisfied United Energy's opex forecast reasonably reflects the opex criteria. Accordingly, the AER considers it is necessary for the AER to substitute United Energy's forecast with the AER's estimate, which the AER considers is the minimum adjustment necessary to be approved in accordance with the NER.[26]

The AER notes that whether or not United Energy transitions to its new business model is a matter entirely for United Energy to determine. In no way does the basis on which the AER accepts or substitutes United Energy's forecast bind the actions or business decisions of United Energy. If United Energy continues on its business transformation process and this leads to lower costs compared to the AER's current business model counterfactual estimate, then United Energy will be financially rewarded for these efficiencies under the EBSS. However, if its new business model leads to higher costs then it will be financially penalised, as is appropriate given the symmetrical nature of the EBSS.

7.5.3 Base year opex

7.5.3.1 Draft decision

Selection of base year

The AER's draft decision on assessing the Victorian DNSPs' initial regulatory proposals (with the exception of United Energy) to apply a base year approach had regard to:

- The actual and expected opex of the Victorian DNSPs during the current regulatory control period.[27] The AER placed emphasis on actual opex incurred by the Victorian DNSPs, given the incentive properties of the regulatory regime, to provide an efficient starting point for forecast opex, albeit based upon adjusted actual opex from the current regulatory control period. In particular, the AER adjusted actual opex (where available) for factors such as non-recurrent costs and related party margins, in determining the AER's estimate of the Victorian DNSPs' required opex for the forthcoming regulatory control period which satisfies the opex criteria.

- Benchmark opex that would be incurred by an efficient DNSP over the regulatory control period.[28] The AER had regard to trend analysis, together with comparative benchmarking of Victorian DNSPs with DNSPs in other jurisdictions.[29] This analysis is presented in appendix H. The results indicated that the Victorian DNSPs compare favourably to those in other states, which suggested that the revealed costs (that is, actual opex) of the Victorian DNSPs provided a sound basis for determining the starting point for evaluating their regulatory proposals.

[25] NER, cll. 6.5.6(c), 6.5.6(a).
[26] NER, cl. 6.12.3(f)(2).
[27] Clause 6.5.6(e)(5) of the NER.
[28] Clause 6.5.6(e)(4) of the NER.
[29] Clause 6.5.6(e)(5) of the NER

- The extent to which the forecast of required opex of the Victorian DNSPs is referable to arrangements with a person other than the service provider that, in the opinion of the AER, do not reflect arm's length terms.[30] The AER considered the issue of related party margins, with CitiPower, Powercor, JEN, SP AusNet and United Energy contracting out certain services to a related party service provider.

As part of their initial regulatory proposals, each Victorian DNSP proposed 2009 as its base year for the purposes of its proposed forecast opex, with the exception of United Energy (who did not apply a base year approach to its opex forecast). The AER's approach was to apply a revealed cost approach in assessing the Victorian DNSPs' proposed forecast opex against the relevant base year. The AER agreed with the Victorian DNSPs (except United Energy) that 2009 be selected as the base year for the 2011–15 regulatory control period on the basis that 2009 represents the most recently available year, within the current regulatory control period, for which actual expenditure is available.

CitiPower, Powercor and SP AusNet provided their unaudited 2009 expenditure for the purposes of the draft decision which the AER accepted as a placeholder for audited 2009 expenditure. The AER used JEN's estimated 2009 costs provided in its initial regulatory proposal as a placeholder for actual audited 2009 expenditure. As discussed in section 7.5.2 and appendix I, United Energy did not provide their 2009 expenditure as it considered it was not necessary given its approach to forecasting opex under its new business model for the forthcoming regulatory control period.[31] The AER in the draft decision did not accept United Energy's forecast opex based on its new business model. The AER assessed United Energy's proposed opex forecast by applying a base year approach. In determining United Energy's base year opex, the AER considered United Energy's estimated opex for 2009 as sourced from the regulatory information notice (RIN) it provided as part of its initial regulatory proposal. However the AER was unable to reconcile United Energy's historical expenditure, excluding margins, with any source material and hence did not accept this approach. Instead, the AER determined United Energy's base year opex based on the following two sources:

- JAM's costs in 2008 of servicing United Energy's network, as reported by JAM to United Energy and verified by PriceWaterhouseCoopers (PWC) (subject to the exclusion of certain cost categories allocated to United Energy, as discussed in sections 6.7.1 and 6.7.3 of the draft decision). The AER noted that these PWC reports are the starting point used by United Energy to complete its regulatory accounting statements and the AER considered these reports reliable. Further, these costs did not include transitional costs associated with United Energy's new business model.

- United Energy's 2009–10 internal costs as provided in its internal corporate opex budgeting model, with the costs associated with its new business model removed. While the AER noted that these costs are estimates, they had the benefit of being a

30 Clause 6.5.6(e)(9) of the NER.

31 The Victorian DNSPs' audited actual 2009 opex was made available late in the draft decision process. The Victorian DNSPs' unaudited reported or estimated base year (2009) costs where available were used by the AER in the draft decision as a placeholder for the Victorian DNSPs' audited 2009 costs to be used in this final decision.

bottom up construction from individual cost categories. Accordingly, the AER reviewed the model line-by-line and removed transitional costs and other costs associated with United Energy's new business model.[32]

The AER did not include within this base year estimate the management and financial services fees that United Energy forecasts it will pay its related parties (DUET and AMP Capital Investors) over the forthcoming regulatory control period. The AER's reasoning for this exclusion is set out in chapter 6 of the draft decision.

The AER also noted that it would update United Energy's base year costs for its final decision following consideration of JAM's 2009 costs of servicing United Energy's network.[33]

Base year costs

The AER in the draft decision made the following adjustments to the base year costs proposed by the Victorian DNSPs to ensure that these costs reflected efficient costs which could be used to assess the forecast opex for the 2011–15 regulatory control period against:

- related party margins - excluded from actual 2009 base year costs on the basis that the AER considers these costs do not form part of a total forecast opex that reasonably reflects the opex criteria (refer to chapter 6 of the draft decision)

- movement in provisions - excluded from actual 2009 base year costs on the basis that (among other things) these may be used to represent the reported accounts of the DNSPs differently from their underlying economic circumstances (refer to chapter 13 of the draft decision)

- distribution licence fees - excluded from actual 2009 base year costs on the basis that the Victorian DNSPs will recover these costs directly through the weighted average price control (refer to chapter 4 of the draft decision)

- a reallocation of costs to AMI services (relevant only to CitiPower and Powercor)[34] - excluded on the basis that these costs are not consistent with CitiPower and Powercor's audited regulatory accounts (refer to chapter 13 of the draft decision).

[32] The AER in the draft decision, in determining the salary and contract staff forecasts, the AER incorporated those staff that United Energy's model indicates were employed in the September quarter 2009 being the initial time period in the model. Additionally the AER excluded the 'salaried staff—regulatory services', 'professional services costs—finance, HR and admin' and 'licenses' categories from the AER's estimate. The first category was excluded on the basis that the 2008 JAM costs will include regulatory services costs for United Energy (the regulatory function was not transferred from JAM to PIES until 2009). The second category was excluded on the basis that it appeared to be for costs already included in the debt raising cost allowance. The third category was excluded as licence fees are compensated for through the form of control. Additionally, the AER adjusted the 'insurance' cost category to exclude United Energy's proposed step change in insurance costs which is considered separately to the base opex.

[33] AER, *Vic Draft Decision*, June 2010, p. 240.

[34] These adjustments were also applied to 2006, 2007 and 2008 to ensure that efficiency carry over reflected expenditure on a like for like basis. The AER' rationale for these adjustments was discussed in the draft decision at chapters 6 and 13.

The AER also made adjustments to the Victorian DNSPs' base year expenditure for the following:

- guaranteed service level (GSL) payments - excluded from actual 2009 base year costs on the basis that actual GSL payments in 2009 are not representative of efficient costs over the forthcoming regulatory control period.

- avoided distribution cost related payments - excluded from actual 2009 base year costs on the basis that costs associated with non-network alternatives are to be excluded from the EBSS for the forthcoming regulatory control period

- an over allocation of related party corporate costs to SP AusNet and United Energy - excluded from base year costs on the basis that these costs do not represent efficient costs

- management fees paid to the parent of a related party (and the relevant DNSP) - excluded from base year costs on the basis that these costs are not an efficient costs and a represent a cost that would not be incurred by a prudent operator, or management fees that may not sufficiently contribute to the provision of distribution services

- corporate cost categories incurred by JEN and United Energy - excluded from base year costs on the basis that these costs may double count costs recovered elsewhere in the regulatory regime (for example, debt raising costs) or other corporate cost categories that do not sufficiently contribute to the provision of distribution services or are not an efficient cost that would be incurred by a prudent operator

- non-recurrent costs - excluded from base year costs to ensure that the base year costs are representative of efficient costs

- adjustments made to base year costs to reflect any changes in capitalisation policy between the current regulatory control period and the forthcoming regulatory control period (CitiPower and Powercor only)

- adjustments to actual 2009 costs to reflect the change in costs between 2009 and 2010 - the AER applied this adjustment to roll forward the Victorian DNSPs actual 2009 costs consistent with the ESCV's approach of assuming that any cost efficiencies achieved by the Victorian DNSPs in the final year of the regulatory control period are zero.

These AER's adjustments and the draft decision base opex for each Victorian DNSP are summarised in Table 7.10:

Table 7.10 AER draft decision adjustments to 2009 base year ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Reported/estimated base opex	36.8	124.9	47.2	141.0	91.2
Movement in provisions	[c-i-c]	[c-i-c]	–	–	–
Distribution licence fees	–0.6	–0.8	–	–0.3	–
AMI reclassifications	–	–	–	–	–
GSL payments	–	–2.0	–	–5.5	–0.1
Avoided distribution costs	–	–	–	–	–
Allocation of overheads to base year	–	–	–	[c-i-c]	[c-i-c]
Exclusion of management fees	–	–	[c-i-c]	[c-i-c]	[c-i-c]
Exclusion of corporate strategy costs	–	–	[c-i-c]	–	[c-i-c]
Non-recurrent expenditure	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Change capitalisation of indirect overheads	–2.9	–4.1	–	–	–
2010 benchmark efficiency adjustment	0.6	4.1	1.5	3.6	–0.2
Draft decision base opex	**32.9**	**115.7**	**44.0**	**117.6**	**85.0**

Source: AER, *Vic Draft Decision*, p. 248.

7.5.3.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs' submitted base year opex (including adjustments) is summarised in Table 7.11 below:

Table 7.11 Victorian DNSP revised proposal base year opex and adjustments ($’m, 2010)

	CitiPower	Powercor	JEN	SP AusNet
Reported base opex	36.6[a]	126.6[b]	51.1[c]	141.0[d]
Related party margins	–	–	–	–0.03
ACS adjustments	–	–	0.2	–
Movement in provisions	1.0	4.9	–	–
Distribution licence fees	–0.2	–0.3	0.1	–0.3
GSL payments	–0.002	–1.8	–	–
Exclusion of management fees	–	–	[c-i-c]	–
Non-recurrent expenditure	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
2010 benchmark efficiency adjustment	0.6	4.4	1.6	5.5
Base opex	**37.1**	**129.6**	**48.7**	**122.6**

Source: [a]CitiPower, *Revised regulatory proposals*, p. 210. [b]Powercor, *Revised regulatory proposals*, p. 199. [c]JEN, *Revised regulatory proposals*, Appendix A02.1-JEN Consolidated RIN Sheet 2.10. [d]SP AusNet, *Revised regulatory proposals*, p. 176.
Totals may not add due to rounding. Note United Energy's initial and revised regulatory proposals estimated forecast opex over the forthcoming regulatory period by applying a bottom up approach based on its new business model

CitiPower and Powercor

CitiPower and Powercor both stated that they assumed that the AER will have regard to the final audited regulatory accounts for 2009 in establishing the base year level of expenditure in its final determination.[35]

CitiPower and Powercor submitted that it has amended its initial regulatory proposal to be consistent with the AER's draft determination in respect of:

- The AER's adjustment to the base year costs to remove regulatory reset costs
- The AER's decision to roll forward the 2009 base year costs to 2010 by inflating the 2009 costs by the change in costs assumed by the ESCV, adjusted for the difference between forecast and actual growth

CitiPower and Powercor submitted that it disputed the AER's adjustments to base year costs for the following:

35 CitiPower, *Revised regulatory proposal*, July 2010, p. 175; Powercor, *Revised regulatory proposal*, July 2010, p. 168.

- adjustment to the movement of provisions in 2009 relating to employee entitlements

- adjustments to exclude related party margins

- adjustment in relation to Powercor's licence fee

- adjustment in respect of GSL payments

- adjustment in respect of capitalisation

- adjustment to the base year costs in respect of superannuation payments[36]

Powercor further submitted that it does not incur any avoided distribution costs and forecasts it will not have any payments over the forthcoming regulatory control period. Powercor also submitted that it does not have any AMI related adjustments in its 2009 audited accounts.[37]

Movement in provisions - employee entitlements
CitiPower and Powercor disagreed with the AER's adjustment for employee entitlements, stating:

- The draft determination uses the unaudited 2009 Regulatory Accounts to calculate the provision movement. However the final 2009 Regulatory Accounts employee entitlement provision statement differs from the unaudited value.

- The draft determination allocates the entire employee entitlement provision movement between capex and opex. The employee entitlement provision for 2009 contains a present value adjustment for long service leave which is made in accordance with accounting standards. This adjustment is driven by assumptions in the present value calculation and therefore remains allocated to opex as per the income statement.

- The draft determination allocates the employee entitlement provision based on the labour costs in the regulatory accounts (which only includes labour costs for the licensee) whereas as it should be based on the labour costs of the ownership group.[38]

Licence fees
CitiPower and Powercor stated that the AER should provide for the actual incurred licence fees for 2009 (both CitiPower and Powercor provided invoices of these fees).[39]

GSL payments
CitiPower and Powercor agreed that, in principle 2009 actual GSL costs should be excluded from the base year, and that an average of GSL payments over 2005–2009

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36 CitiPower, *Revised regulatory proposal*, July 2010, p. 178; Powercor, *Revised regulatory proposal*, p. 168.
37 ibid.
38 CitiPower, *Revised regulatory proposal*, p. 179; Powercor, *Revised regulatory proposal*, p. 169.
39 CitiPower, *Revised regulatory proposal*, p. 180; Powercor, *Revised regulatory proposal*, p. 170.

should be used. However, both CitiPower and Powercor disagreed with the AER's rejection of a customer growth factor to the average GSL payment value. [40]

Capitalisation adjustment

CitiPower and Powercor both stated that the AER erred in its draft decision, stating:

- the AER rejected CitiPower and Powercor's forecast opex and capex, however, it applied a similar step change decrease in standard control opex due to increased capitalisation of overheads
- the AER applied the adjustment to indirect overheads only, but it should have applied the adjustment proportionally across indirect and direct overheads
- the AER made a one-off adjustment to the 2009 base year cost which effectively assumed that the adjustment was equal in each year of the regulatory control period. However, the amount of the adjustment should vary in each year of the regulatory control period as the ratio of capex to total costs changes
- the AER does not appear to have adjusted the amount for related party margins. The adjustment in original regulatory proposal included related party margins. However, the AER has excluded related party margins from forecast capex and opex in its draft determination
- if the AER determines to exclude related party margins in its final determination, it should make an adjustment to the proposed adjustment for margins; and
- the AER did not re-allocate the overheads associated with proposed step changes.[41]

JEN

JEN stated that the AER approved the use of a 'revealed cost base year roll-forward approach' to opex forecasting. JEN also noted that the draft decision indicated that its base year opex costs would be updated for actual costs and notes the AER accepted its proposals to adjust base year costs for:

- identified one-off costs
- the benchmark efficiency adjustment forecast by the ESCV between 2009 and 2010
- the removal of alternative control operating costs.[42]

JEN submitted that it has updated its 2009 opex costs in its regulatory proposal for the full year of actual data drawn from its 2009 audited regulatory accounts. JEN also stated that the updated corporate costs based on actual 2009 costs require JEN to update its once-off costs. JEN submitted that the original one-off corporate costs approved by the AER in the draft decision related to 2008, and all bar one of these

[40] CitiPower, *Revised regulatory proposal,* p. 181; Powercor, *Revised regulatory proposal,* p. 171.
[41] CitiPower, *Revised regulatory proposal,* p. 183; Powercor, *Revised regulatory proposal,* p. 173.
[42] JEN, *Revised regulatory proposal,* July 2010, p. 104.

projects were relevant to 2008. In addition, JEN considers that it has shared a one-off provision write back with Jemena Limited which has the effect of lowering JEN's reported corporate opex below recurrent levels.[43]

JEN stated that it agrees with the intent of the AER's adjustment to the 2009 opex costs for the benchmark efficiency adjustment forecast by the ESCV between 2009 and 2010. JEN also stated that this adjustment should be based on the growth adjusted opex forecasts used in the EBSS calculation as failure to do so means that JEN only receives the EBSS growth adjustment for four of the five years. The consequence is that the EBSS will not provide even efficiency incentives for each year of the regulatory period.[44]

Finally, JEN submitted that it has deducted the value of the costs the AER attributes to alternative control services.[45] JEN considered that given the link between alternative control services and standard control services if the AER's final decision on costs and prices differs from JEN's revised proposals, JEN requested the AER provide an opportunity to make consequential amendments to its forecast data model.[46]

SP AusNet

Utilising the ESCV’s 2006 Final Decision to convert 2009 to 2010

SP AusNet did not agree with the AER’s draft decision in relation to the AER’s methodology for escalating 2009 costs to 2010 costs. SP AusNet considered that this methodology leads to operating expenditure forecasts for the 2011–2015 regulatory control period that are not consistent with the requirements of clause 6.5.6 (c)(1) of the NER. In particular, SP AusNet contends that this clause requires the AER to have regard to the impact that their 2010 forecast has on determining efficient operating expenditure forecasts for the 2011–15 period.[47]

SP AusNet also disagreed with the AER's underlying justification of preserving the ESCV methodology to roll forward 2009 costs to 2010. SP AusNet stated that the AER's approach is contrary to section 7A(2) of the NEL which requires that the DNSPs be provided with a reasonable opportunity to recover at least their efficient costs. SP AusNet also sated that there is a disconnect between the AER's escalation approach for opex and its proposed approach for capex. Specifically, SP AusNet stated:

> Finally, SP AusNet also notes that there is a significant disconnect between the AER’s proposed escalation approach for opex, and its proposed approach to capex. The latter, quite appropriately given the requirements placed upon the businesses and the AER under the NEL and the NER, has regard for the most up to date information with regards to labour and materials escalators in the 2010 calendar year to determine capex unit rates which are then used to derive capex forecasts for the 2011 to 2015 regulatory control period. However, as noted previously, the AER’s

43 ibid., pp. 104 –105.
44 ibid., p. 107.
45 ibid., p. 108.
46 ibid., p. 108.
47 ibid., pp. 174–75.

> approach to opex effectively disregards this most up to date information, and instead, reverts to information contained in a decision from 5 years ago.[48]

United Energy

Removal of non recurrent costs

United Energy noted that the costs removed by the AER form part of the audited costs incurred by JAM in providing services to United Energy. United Energy further stated that there is no basis for the AER's assertion that these costs are non-recurrent. United Energy maintains its view that the AER cannot remove efficient costs that it expects to incur in its new business model simply because the AER wishes to adhere to a mechanical 'year 4' forecasting methodology.[49]

Projection from 2009 regulatory accounts

United Energy noted that the AER's approach preserves assumptions and calculations made by the ESCV in its 2006 EDPR. However, the NER requires United Energy to forecast its operating expenditure for the forthcoming regulatory period. Therefore, it is not reasonable to forecast cost movements between 2009 and 2010 using assumptions made by the ESCV in October 2005. United Energy maintains that the AER should adopt its own estimate of the change in operating expenditure between 2009 and 2010. United Energy stated:

> For the purpose of establishing an appropriate base year cost in the context of the AER's 'year 4' approach, UED has adopted the composite scaling factor and labour rate of 1.87% per annum…UED contends that this approach is reasonable and should be adopted for the purposes of establishing UED's base year costs.[50]

United Energy also submitted:

- The ESC's profile for step change cost allowance is markedly different for United Energy compared to the other DNSPs
- The ESC's profile for United Energy's step change cost allowance changed between the draft and the final decisions, and there is no explanation for the change from the ESC's final decision or United Energy's submission in response to the draft decision
- If the AER maintains the ESC's profile assumption for United Energy, its effect will be to impose a decrease in United Energy's base year costs compared to 2009, whereas all other DNSPs will be allowed an increase in their base costs and that such an outcome would be biased and unreasonable because it would rely on an error or unreasonable assumption in the ESC's final decision; and
- It is appropriate for the AER to make an adjustment to the ESC's profile of step changes for the purposes of forecasting United Energy's operating expenditure. The operation of the ESC's efficiency carryover mechanism is separate to the task

48 ibid., p. 175.
49 United Energy, *Revised regulatory proposal*, p. 69.
50 ibid., p. 75.

of deriving an estimate of United Energy's future operating expenditure requirements.[51]

Escalation of 2009 cost data to 2010

United Energy submitted that the AER's base year cost approach applies an adjustment to express the 2009 base year costs in 2010 price levels. A standard approach for expressing 2009 costs in 2010 price levels is to apply an estimate of the change in the CPI from 2009 to 2010. However, the AER has adjusted the base year for historic inflation, rather than forecast inflation. There is no sound reason to adopt historic CPI data in preference to forecast data and United Energy has therefore amended the base year cost to the reflect forecast increase in CPI of 2.57 per cent.[52]

7.5.3.3 Submissions

The AER received two stakeholder submissions that discussed the AER's approach to base year costs.

The EUAA stated:

> The AER has selected 2009 as the "benchmark" opex that would be incurred by "an efficient DNSP over the regulatory control period". The AER states that it uses the last known costs, or penultimate year, as the benchmark year. Once this has been established, the AER adjusts the base year figures to set an allowed expenditure. This approach relies on the idea that the "revealed expenditure", i.e. the expenditure that the business incurred in some previous year is, by definition, efficient expenditure.20 This appears to be based on the view that opex generally does not vary much in its composition from year to year (with respect to various subcategories of expenditure). That is, the main change is due to various rate escalations, and that therefore the most recent years expenditures and their composition provides the most up to date estimate of their true or efficient costs. This could presumably be contrasted to capex where its variability can be expected due to discrete large project related expenditures that are irregular and require several years to complete. This assumption is not borne out in practice, however, if one analyses actual opex and capex from 1996 to 2008 (all available data since privatisation).[53]

The EUAA also noted year on year variability in costs. It stated that this casts doubt over assumptions which regard the last year of the period reflecting efficient costs. The EUAA noted that, whilst it may be reflective of efficient costs, there is no evidence that the final year must be the most efficient. The AER should identify a more robust method of assessing efficient opex.[54]

The EUAA supported the AER's use of audited expenditures when assessing its final decision.[55]

The EUCV stated:

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[51] ibid., p. 79.
[52] United Energy, *Revised Regulatory proposal*, p. 81.
[53] EUAA, *Submission on the AER 2010 draft decision on the Victorian DNSPs price proposals,* August 2010, p. 33.
[54] ibid, p. 34.
[55] ibid, p. 35.

> Whilst the EUCV does accept that basic approach used by the AER to set the forward opex allowances, it raised in its response to the DB applications, concerns that selecting a single pre-identified year as the starting point for developing the efficient and prudent opex is the second last year of the current period, being that one where the last known actual opex is revealed. The AER has expressed its view that because of the incentive scheme there is no incentive on a DB to artificially inflate the opex in the defined year.
>
> The EUCV is not as sanguine about this presumption as the AER appears to be. Notwithstanding this reservation, the EUCV has observed there is considerable variation of actual opex for all years, and there appears to be a trend in the actual opex incurred and this is replicated over two regulatory periods.[56]

The EUCV cited consistent opex increases towards the next regulatory period and stated that this could be attributed to the continuously increasing demand and consumption that all the DNSPs have demonstrated. However, the EUCV noted concern that between the fifth year of the early regulatory period and the early years of the following period, there is a distinct fall in opex, even though demand and consumption continues to increase.

On United Energy's approach to opex, the EUCV noted:

> The EUCV agrees that the AER argument for not allowing the United Energy's approach to be incorporated in the opex element of the allowed tariffs for the new regulatory period is strong and cogent, and reflects current efficiency and prudency.
>
> What the AER did not address is that United is permitted to expend its opex in any way it sees fit, only that the efficient and prudent opex will be allowed into the tariffs. If United considers that its new approach will result in savings then it can make the decision to implement the new approach and under the EBSS, will be able to retain the benefit of the savings it generates in this and the next regulatory period.
>
> The EUCV supports the principle that a DB has the freedom to initiate approaches to improve long term efficiency and because of this the EUCV accepts that a DB (United in this case) should be rewarded if its initiative results on a more efficient outcome. The EUCV considers that what the AER has implied in its draft decision, is that United can develop its opex approach in any way it wants to but the AER will not allow United to increase tariffs as a result of the new approach.[57]

7.5.3.4 Issues and AER considerations

Selection of base year

The AER in the draft decision adopted 2009 as the base year from which to assess the Victorian DNSPs' forecast opex for the forthcoming regulatory control period. The AER maintains its view that 2009 is likely to represent the efficient level of opex given the incentives for Victorian DNSPs to reduce costs under the regulatory framework. In addition, as noted in the draft decision the application of an ECM and

56 EUCV, *2010 AER review of Victorian Electricity DBs: EUCV response to AER Draft Decision*, August 2010, pp. 34-35.
57 ibid., pp. 35-36.

EBSS provides the AER with some confidence that the last known year of actual costs is reflective of efficient costs in that year

In response to the submissions from EUCV and EUAA on the choice of actual 2009 expenditure as base year, the AER acknowledges the year on year variability in costs by the Victorian DNSPs and the concerns regarding whether the last known year of actual opex in the regulatory period reflects efficient costs. However, as stated in the draft decision:

> The AER has undertaken trend analysis (opex factor 3), together with comparative benchmarking of Victorian DNSPs with DNSPs in other jurisdictions (opex factor 4).
>
> The results reveal that the Victorian DNSPs compare favourably to those in other states, which suggests that the revealed costs of the Victorian DNSPs is a sound base for determining the starting point for evaluating their regulatory proposals. [58]

In response to the EUAA's observation that the DNSPs’ opex over the current regulatory period has been volatile, the AER notes that under the ESCV's ECM that where opex substantially increases between regulatory years the Victorian DNSPs will be penalised for unsustainable efficiencies from prior years through the ECM. Therefore, the AER maintains that 2009 is likely to represent efficient costs in assessing the Victorian DNSPs’ forecast opex over the 2011–15 regulatory control period.

That said while the AER has relied on the revealed cost approach to assess the Victorian DNSPs' opex proposals, in the draft decision the AER identified a number of factors that suggest the Victorian DNSPs' actual reported expenditure at a particular point in time is not efficient.[59] Accordingly, where necessary, the AER made the adjustments to the base year level of expenditure proposed by the Victorian DNSPs it considered necessary to ensure that the underlying costs represent efficient expenditure that can be used to assess the forecast opex for the forthcoming regulatory control period.

The AER maintains its position that these adjustments are the minimum necessary to ensure that the Victorian DNSPs forecast opex is consistent with the NER.[60]

AER conclusion on selection of base year

The AER maintains its decision that 2009 costs are likely to reflect the efficient starting point for assessing the Victorian DNSPs’ forecast opex over the forthcoming regulatory control period. The AER also considers that the Victorian DNSPs’ actual 2009 costs should be adjusted for factors identified in the draft decision to ensure that base year costs reflect the efficient costs of a prudent operator in the circumstances of each DNSP in accordance with clause 6.5.6(c)(1) and (2) of the NER.

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58 AER, *Vic Draft Decision*, June 2010, p. 236
59 AER, *Vic Draft Decision*, June 2010, p. 236
60 NER, cl. 6.12.3(f)(2).

Base year costs

The AER maintains its draft decision position that it is necessary to adjust the Victorian DNSPs' audited 2009 base year costs for the following factors:

- related party margins
- movement in provisions
- distribution licence fees.

The AER's reasons for applying these adjustments is discussed further in chapter 6 and chapter 13. Consistent with its approach in the draft decision, the AER also considers that it is necessary to adjust the Victorian DNSPs' reported base year expenditure for:

- guaranteed service level (GSL) payments
- an over allocation of a related party's corporate costs to the DNSP (refer to chapter 6 for the AER's consideration of this issue)
- management fees paid to the parent of a related party (and the DNSP) that are not an efficient cost and a cost that would not be incurred by a prudent operator, or management fees that may not sufficiently contribute to the provision of distribution services (refer to chapter 6 for the AER's consideration of this issue)
- corporate cost categories that do not sufficiently contribute to the provision of distribution services or are not an efficient cost that would be incurred by a prudent operator (refer to chapter 6 for the AER's consideration of this issue)
- avoided distribution cost payments
- where necessary, the removal of non-recurrent costs to ensure that the base year costs are representative of efficient costs
- any changes in capitalisation policy between the current regulatory control period and the forthcoming regulatory control period.
- the roll forward of actual 2009 costs for the expected costs in 2010 based on a benchmark efficiency adjustment.

The AER's consideration of the Victorian DNSPs’ revised regulatory proposals in relation to these adjustments and specific adjustments proposed by the Victorian DNSPs is discussed below.

Related party margins

CitiPower, Powercor and JEN did not agree with the AER's draft decision to exclude their related party margins from forecast base opex over the forthcoming regulatory control period. United Energy submitted that it is appropriate to include a profit margin as a percentage of JAM's outsourced costs, and has therefore included a 6 per cent margin to the base year costs. [61]

As discussed in chapter 6, the AER has maintained its draft decision to remove related party margins from the Victorian DNSPs' base opex forecasts. The AER has therefore applied the Victorian DNSPs' 2009 regulatory accounting statements exclusive of related party margins to establish the base level of opex for the final decision.

Movement in provisions

As discussed in chapter 13, the AER has reviewed CitiPower and Powercor's proposed adjustment to the provisions relating to 2009 employee entitlements and accepted these adjustments on the basis that these changes have been externally audited.

JEN's revised regulatory proposal included a superannuation provision write-back adjustment of $0.2 million for 2009.[62] The AER notes that this adjustment was not separately identified in JEN's forecast data model that accompanied its revised regulatory proposal. JEN subsequently provided information to the AER verifying this adjustment.[63] The AER has accepted JEN's adjustment was included in its forecast data model on the basis of this further information and included this amount in JEN's base opex.

As discussed in chapter 13, the AER has also accepted SP AusNet's proposed provision adjustments to its 2009 base opex on the basis that these adjustments are consistent with its regulatory accounting statements.

Distribution licence fee

The Victorian DNSPs either agreed with, or did not comment on, the exclusion of licence fees from the base year in the draft decision. However, CitiPower and Powercor disputed the actual amount of the AER's adjustments for licence fees. In response to the draft decision, the Victorian DNSPs provided actual licence fees paid in 2009 or in United Energy's case in response to a previous information request.[64] The AER has accepted these revised licence fees and excluded these costs from the Victorian DNSPs' base year opex.

Guaranteed Service Level payments

The Victorian DNSPs either agreed with or did not comment on the removal of GSL payments from opex in the base year in the draft decision.[65] CitiPower and Powercor did not agree with the AER's approach to estimating GSL payments for the 2011–15 regulatory control period. The AER's decision on forecast GSL payments is set out in chapter 15). [66]

[61] United Energy, *Revised regulatory proposal*, pp. 80–81.

[62] JEN, *Revised regulatory proposal*, p.206.

[63] JEN, *Response to AER's information requested 13 September 2010*, 29 September 2010.

[64] CitiPower, Powercor, and JEN, revised RIN. SP AusNet, UED provided its actual licence fee in February 2010.

[65] CitiPower, *Revised regulatory proposal*, p. 173; Powercor, *Revised regulatory proposal*, p. 170; SP AusNet, Revised regulatory proposal, p. 265.

[66] CitiPower, *Revised regulatory proposal*, p. 173; Powercor, *Revised regulatory proposal*, p. 170.

JEN, SP AusNet and United Energy did not respond to the AER's draft decision. As discussed above, the AER has removed actual 2009 GSL payments from their respective base year amounts.

Avoided distribution cost payments

The AER's draft decision required the Victorian DNSPs to provide forecast operating expenditure associated with any avoided distribution cost payments to embedded generators. The AER required these costs to be separately identified on the basis that the EBSS excludes opex related to non-network activities.

CitiPower and Powercor, in response to the draft decision, and JEN, SP AusNet and United Energy, in response to a request for further information, advised that they did not incur any costs associated with any avoided distribution cost payments in the base year and do not expect to incur any costs over the forthcoming regulatory control period.[67] Therefore no adjustments were made to the base opex in relation to avoided distribution cost payments to embedded generators.

Non-recurrent costs

Regulatory reset costs

The AER excluded these costs in the draft decision on the basis that these costs are not expected to be incurred in every year of the forthcoming regulatory control period. Accordingly, the AER removed 2009 actual regulatory reset costs from the base year opex for the Victorian DNSPs, with the exception of SP AusNet.[68] The AER provided the Victorian DNSPs with reset costs in 2014 and 2015 which reflects the period in the 2011–15 regulatory control period where some additional regulatory costs are expected to be incurred. CitiPower and Powercor have amended their regulatory proposals to be consistent with the AER's draft decision in relation to the AER's adjustment to base year costs to remove regulatory reset costs. [69] The other DNSPs did not comment on the removal of regulatory reset costs from opex in the base year in the draft decision.

The AER has maintained its draft decision to remove these costs from the base year.

ATO audit costs

Powercor excluded the ATO audit costs of $2.0 million ($2010) from the 2009 base year on the basis that these costs are not recurrent costs. The AER accepted this adjustment in the draft decision. The AER maintains its decision to exclude these costs from Powercor's base year costs.

Superannuation payments

Powercor and CitiPower did not agree with the draft decision to exclude superannuation related costs from CitiPower's and Powercor’s base year opex of $1.7 million ($2010) and $5 million ($2010), respectively, on the basis that:

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[67] JEN, *Response to the AER's information requested 24 August 2010*, 2 September 2010; SP AusNet, Response to the AER's information requested 30 August 2010, 31 August 2010; United Energy, Response to the AER's information requested 6 September 2010, 15 September 2010;

[68] SP AusNet provided evidence that its regulatory costs have not materially fluctuated over the current regulatory control period and that it would not experience a significant increase in expenditure in its base year.

[69] CitiPower, *Revised regulatory proposal*, July 2010, p. 177; Powercor, *Revised regulatory proposal*, p. 166.

- the adjustments were based on all superannuation contributions rather than the defined benefits contribution portion

- the AER used, as a base, the costs incurred over 2006–08 which are artificially low as a result of favourable market conditions during that time.[70]

CitiPower and Powercor in their revised regulatory proposals included in their base opex, all superannuation costs associated with the defined benefit superannuation scheme.[71] In the draft decision the AER considered that fluctuations in required superannuation contributions are likely to be symmetrical as financial conditions are likely to fluctuate such that any actuarial adjustments are likely to balance out over time. However, the AER also considered that the impact of the recent global financial crisis was such that any actuarial adjustments related to defined benefit scheme contributions reflected in the base year are not likely to reflect efficient costs over the forthcoming regulatory control period.[72]

The AER acknowledges that it applied this adjustment to all superannuation costs, whereas this adjustment should only be applied to defined benefit scheme costs. The AER also recognises that in relation to any actuarial adjustments related to defined benefit schemes, market conditions in 2006 and 2007 (pre GFC) may have been more favourable than historical norms.[73] As a result, the AER acknowledges that the AER's adjustment to the base year in the draft decision may under represent CitiPower and Powercor's expected superannuation costs over the forthcoming regulatory control period. Accordingly, the AER has not applied this adjustment to CitiPower and Powercor's base year costs for the final decision. The AER's consideration of CitiPower and Powercor's step change costs for superannuation is considered in appendix L.

The AER in the draft decision accepted SP AusNet's initial regulatory proposal (and updated costs) to exclude its actuarial adjustment of $3.0 million ($2010) from its base year opex on the basis that these costs represent a one off adjustment in their regulatory accounts.[74] The AER for the final decision has excluded costs of $3.0 million from SP AusNet's base year costs.

JEN and United Energy confirmed that no actuarial adjustments in relation to the employee defined superannuation benefits schemes were included in their 2009 regulatory accounts, which the AER accepts, resulting no adjustment to their 2009 base opex in relation to the employee defined superannuation benefits schemes.[75]

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70 CitiPower, *Revised regulatory proposal*, July 2010, pp. 187–89; Powercor, *Revised regulatory proposal*, pp. 175–78.

71 CitiPower and Powercor then applied a step change for the 2011–15 based on the difference between 2009 defined benefit contributions and an actuarial assessment of its defined benefit contributions and as determined by Mercer, the actuary for the fund. The AER has considered this step change in appendix L.

72 AER, *Vic Draft Decisio*n, June 2010, p. 244.

73 The AER notes that the historical market risk premium is significantly affected where data is used up to 2007 or alternatively 2008.

74 SP AusNet, *Electricity distribution price review, 2011–2015, Revised regulatory proposal*, July 2010, p. 172.

75 JEN, *Response to the AER on Employee defined benefit superannuation schemes*, 10 September 2010; United Energy, *Response to the AER's information request*, 6 September 2010.

Bushfire and heatwave costs

The AER in the draft decision accepted SP AusNet's initial regulatory proposal (and updated costs) to exclude bushfire and heatwave costs associated with the February 2009 bushfires. The AER for the final decision has excluded costs of $13.9 m from SP AusNet's base year costs.

Jemena Limited and Jemena Asset Management

In response to the draft decision JEN has provided revised one-off costs to reflect 2009 actual direct JEN and JAM costs. The AER notes that an equivalent PWC report for 2009 has not been provided by JAM to JEN. JEN has advised that a report was not conducted in relation to 2009 costs.[76]

JEN has stated that all of the non recurrent costs that occurred in 2008, with the exception of one of those costs apply in 2009. The AER has excluded those non recurrent costs of $[c-i-c] million from JEN's base year opex.

Since a proportion of these costs are also allocated to United Energy the AER has reduced United Energy's base year amount for a proportion of this cost. The AER has assessed the amount allocated to United Energy based on the proportion of this cost item relative to the total non recurrent costs allocated to United Energy by Jemena Limited in 2008. This results in an amount of $[c-i-c] million, which the AER has excluded from United Energy's base year for this final decision.

Changes in capitalisation policy

The AER in the draft decision accepted CitiPower and Powercor's proposals to capitalise more of its indirect overheads over the forthcoming regulatory control period. This resulted in a reduction of base year of for Citipower of $2.9 million and Powercor of $4.1 million, respectively.

The AER acknowledges that the AER adopted CitiPower and Powercor's step change decrease to the base year for capitalised overheads (that is a reduction in base year opex) which was decoupled from CitiPower and Powercor's forecast capex and opex from which this step change was derived.[77] The AER also notes that CitiPower and Powercor submitted that these overheads include related party margins which suggests the downwards adjustment was higher than appropriate. The AER is cognisant that both CitiPower and Powercor have stated that they have not changed their capitalisation policies over the forthcoming regulatory control period.

The AER has therefore 'rolled forward' CitiPower and Powercor's indirect capitalised overheads as reported in their 2009 regulatory accounts exclusive of related party margins (and as reported in their respective RINs) to determine CitiPower and Powercor's 'base' forecast amounts for each year of the forthcoming regulatory control period. The AER has also applied scale and real cost escalation to the 'base' forecast amount to determine CitiPower and Powercor's total forecast for indirect capitalised overheads over the forthcoming regulatory period. The AER has applied this approach for all of the Victorian DNSPs given that the DNSPs have advised that the capitalisation policies over 2011–15 are not expected to change. The AER’s approach is discussed in more detail in chapter 8.

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[76] JEN, *Response to AER's information requested 8 September 2010*, 17 September 2010.

[77] CitiPower/Powercor, *Cost escalation and forecast templates and data*, 31 March 2010, p. 15

In conclusion the AER accepts CitiPower and Powercor's arguments that the step change reduction in capitalised indirect overheads would under compensate CitiPower and Powercor. Accordingly, the AER has removed the base year adjustment in the draft decision. The AER's allowance in the final decision for capitalised indirect overheads is discussed in chapter 8.

Alternative control services

JEN has included a positive adjustment to its reported base year costs (2009) on the basis that it has applied updated information to determine the costs associated with providing alternative control services (and in turn standard control services). The AER understands that this has required a positive adjustment to standard control services for the forthcoming regulatory control period. The AER has reviewed the modelling regarding this adjustment in JEN's forecast data model (appendix 18.3 of JEN's revised proposal), and concludes that JEN has appropriately adjusted its base year opex for standard control services.

United Energy agreed with the AER draft decision to exclude $2.6 million based on an allocation of JAM's costs to alternative control services. The AER has applied this adjustment for this final decision as part of its counterfactual cost estimate (refer to appendix I).

Change in base year costs between 2009 and 2010 – efficiency adjustment

CitiPower and Powercor agreed with the AER's draft decision to roll forward the 2009 base year costs to 2010 by inflating the 2009 costs by the change in costs assumed by the ESCV, adjusted for the difference between forecast and actual growth. As discussed below, the AER has applied the latest growth estimates (given actual information for 2010 is not available) from the Victorian DNSPs to estimate the growth adjustment for 2010.

In rolling forward base year costs (2009) to 2010 the AER applied the ESCV's growth formula updated for 2010 growth which is based on the latest estimates by the Victorian DNSPs for each of the ESCV's growth components (refer to chapter 13).[78] The AER as discussed in the draft decision rolled forward the 2009 base year costs to 2010 consistent with the approach proposed by JEN in its initial regulatory proposal. The AER adopted this approach as it is consistent with the ESCV's approach of assuming that any cost efficiencies achieved by the Victorian DNSPs in the final year of the regulatory period is zero.[79] The AER noted that this is also the case under the AER's EBSS (where 'year 4' of the regulatory control period is used as the base year).[80]

JEN argued that under the AER's approach it will only receive the EBSS growth adjustment for four of the five years and so this will not provide even efficiency incentives for each year of the regulatory control period. The AER considers that contrary to JEN's claim the Victorian DNSPs will still have incentives to make

78 The ESCV's network growth components included energy customer numbers, energy consumption and peak demand.

79 AER, *Vic Draft Decision*, p. 246.

80 The AER under the EBSS would update its growth formula for the latest estimates of the last year of the regulatory control period (that is, 2014) in determining the opex forecast for the 2016-20 regulatory control period. This is necessary as the EBSS also assumes efficiencies in the last year of the regulatory control period will be zero.

efficiency savings in 2010. Further the AER considers that the Victorian DNSPs will still receive the benefits of any efficiency savings for a period of five years under the EBSS for savings arising from within the regulatory control period, regardless of the growth adjustment used to establish the opex forecast. That said, as noted above if the EBSS growth formula is used to roll forward 2009 costs to 2010, this does not maintain the assumption that the cost efficiencies achieved by the Victorian DNSPs will be zero in the final year of a regulatory control period in accordance with the EBSS final decision (which applies the ECM).

The AER agrees with SP AusNet's view that the 2010 benchmark allowances do not impact on incentives for the businesses to seek efficiencies in 2010, but where efficiencies in the last year of the regulatory control period are not assumed to be zero, this will affect the amount of any efficiency rewards or penalties retained by the DNSPs over the next five years. More significantly, SP AusNet considers the AER's proposed approach is inconsistent with the section 7A(2) of the NEL. Specifically SP AusNet argued that:

- the AER's proposed approach embeds any under or over forecast into the 2011–15 forecasts
- the use of the most up to date information with regard to labour cost escalators, scale escalation minimises the risk that this will occur
- this is particularly the case with the use of an escalation approach that relies on underlying assumptions that stem from a decision that was made five years before
- there is a disconnect between the AER's approach to opex and capex, where quite appropriately given the requirements placed on the businesses and the AER under the NEL and NER, the AER has had regard to labour and materials escalators in 2010 to derive the capex for the 2011–15 regulatory control period.[81]

United Energy also stated that the NER requires United Energy to forecast its opex over the forthcoming regulatory control period and as such it is not reasonable to forecast cost movements between 2009 and 2010 using assumptions made by the ESCV in October 2005.

In the draft decision the AER rolled forward 2009 costs to 2010 by applying the ESCV's methodology in relation to network growth (the equivalent to the AER's scale escalation applied to the 2011–15 regulatory control period) which as been updated for the Victorian DNSPs' estimates of growth for 2010. The AER has also applied the ESCV's assumed real labour cost escalation (which is equivalent to the AER's real cost escalation approach).[82] In summary, the AER in rolling forward the 2009 base year costs to 2010:

- used the latest information for network growth to estimate the increase in costs between 2009 and 2010 using the ESCV's methodology

81 SP AusNet, *Revised regulatory proposal*, pp. 174–75.

82 It should be noted that the ESCV provided for expected real labour cot escalation, while the AER applies both a real labour and materials escalator.

- applied the difference between actual opex in the base year (2009) and the assumed efficiencies between 2009 and 2010 (that is, the difference between the ESCV's 2009 and 2010 benchmark allowances).

The AER under this approach does not consider that the Victorian DNSPs will be denied a reasonable opportunity to recover at least their efficient costs (section 7A(2) of the NEL) given that the roll forward of 2009 to 2010 costs provides updated scale escalation and implicit compensation for real labour cost escalation assumed by the ESCV. Furthermore these costs represent only one element of the Victorian DNSPs' building block revenue allowance. The requirements of section 7A(2) of the NEL are to be assessed based on the total revenue allowance across all components of the DNSPs' building block revenue requirements.

Nevertheless, the AER acknowledges SP AusNet and United Energy's proposals and considers that more up to date cost information is likely to provide a more realistic expectation of the demand forecasts and costs inputs required to achieve the operating expenditure objectives. In the draft decision, the AER included updated forecasts for 2010 in relation to network growth but not in relation to real cost escalation. The AER also notes SP AusNet's comment that the AER's approach differs between opex and capex. It is important to recognise that the AER's approach to capex in the draft decision differed given there is no ECM on capex.

In response to SP AusNet and United Energy's concerns the AER has reviewed the Victorian DNSPs' proposed real input cost escalation between 2009 and 2010. The AER has adjusted the Victorian DNSPs' proposed labour cost escalation component based on the Labour Price Index measure given that the AER considers this measure to be more appropriate (refer to appendix K). The AER notes that this results in real input cost changes of around 0.5 per cent or less for the Victorian DNSPs compared to the ESCV's assumed change in real input (labour) costs of 0.59 per cent between 2009 and 2010. As this rate of change in real input costs between 2009 and 2010 is similar to the ESCV's assumed real input cost change and in some cases lower, the AER has applied the ESCV's benchmark efficiencies to roll forward the Victorian DNSPs costs between 2009 and 2010.

In summary in rolling forward the Victorian DNSPs' 2009 costs to 2010, the AER has:

- applied the ESCV opex growth methodology updated for the latest estimates of 2010 provided by the Victorian DNSPs and

- applied the ESCV assumed rate of change in real input costs of 0.59 per cent given that this growth is the similar to the Victorian DNSPs' updated estimates for 2010 based on the Labour Price Index rather than AWOTE.

The AER considers that applying this approach is consistent with a total forecast opex that reasonably reflects the opex criteria, in particular a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives, per clause 6.5.6(c)(3) of the NER

In response to the draft decision United Energy considered that the AER' approach, in relying on the assumptions in the ESCV's final decision, would be biased and unreasonable because it would rely on an error or unreasonable assumption in the ESCV's final decision.[83] The AER applied a negative efficiency amount in rolling forward costs between 2009 and 2010 for United Energy in the draft decision. This negative efficiency adjustment arose due to the profile of United Energy's benchmark allowances contained in the ESCV's 2006–10 EDPR. United Energy stated this profile is markedly different from the other businesses and the ESCV's step change allowance profile changed between the draft and final decision and there is no explanation in the ESCV's final decision. [84]

The AER has reviewed the ESCV's final decision (2006–10 EDPR) and notes that United Energy's opex benchmark profile in the ESCV's final decision is affected by the ESCV's allowance for earthing and electrical protection.[85] The AER notes that the ESCV final decision suggests that it has provided an even allowance for these step change costs over 2006–10.[86]

However, the AER agrees with United Energy that the benchmark allowance profile between 2009 and 2010 in the draft decision is not consistent with the ESCV's reasoning in its final decision. Accordingly, the AER has recalculated United Energy's benchmark efficiencies between 2009 and 2010 for this final decision based on a benchmark allowance that provides a smoothed or even profile of expected opex associated earthing and electrical protection (subject to the adjustments for network growth and real cost escalation discussed above).[87] These efficiencies reflect the AER's adjusted profile of the ESCV benchmark allowances for total opex for 2009 and 2010 which reflects the description as contained in the ESCV's final decision.

CPI escalation of 2009 costs to 2010

United Energy submitted that the AER has adjusted the base year opex for historic inflation, rather than forecast inflation. United Energy stated that there is no sound reason to adopt historic CPI data in preference to forecast data and United Energy has therefore amended the base year cost to the reflect forecast increase in CPI of 2.57 per cent.[88]

The AER has not accepted United Energy's proposed escalation of base year opex on the basis that United Energy's approach is inconsistent with the AER's price control mechanism to escalate distribution tariffs for CPI over the regulatory control period. In particular, the building block revenues in the final decision from which the Victorian DNSPs tariffs for standard control services will be derived uses a lagged CPI (where $2010 is based on the September quarter 2009 CPI) as a proxy for the actual CPI for 2010. Importantly, the AER has also applied the September quarter CPI preceding the commencement of the regulatory year (for example, the change in September quarter CPI for 2010 and the September quarter 2009 is used to escalate tariffs for standard control services in 2011. (The AER's CPI escalation approach is detailed in chapter 4).

83 United Energy, *Revised regulatory proposal*, p. 79.
84 ibid., p. 79.
85 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 220.
86 ibid., p.221.
87 The AER's adjusted ESCV benchmark allowances are consistent with the ESCV's approach in the 2006 EDPR as described by the ESCV where it states that it has provided an even allowance for earthing and electrical protection over the 2006–10 regulatory period.
88 ibid., p. 81.

7.5.3.5 AER conclusion

This section has assessed the proposed allowance for base opex which is one component of each Victorian DNSP's proposed total forecast operating expenditure. The AER considers that the level of base opex determined in this section is consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast operating expenditure reasonably reflects the operating expenditure criteria. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each Victorian DNSP's total forecast operating expenditure.

The AER's final decision adjustments are provided in Table 7.12 below. Based on the consideration of the following opex factors: [89]

- the information in and accompanying the Victorian DNSPs' revised proposals
- analysis undertaken by the AER, the Victoria DNSPs' actual opex and expected opex preceding the 2011–15 regulatory control period
- the extent that the Victorian DNSPs' forecast opex is referrable to arrangements which in the opinion of the AER do not reflect arms length terms

Based on the analysis above, the AER considers that the Victorian DNSPs' base opex proposals do not form part of a total opex forecast that reasonably reflects:

- the efficient costs that a prudent operator in the circumstances of each DNSP would require to achieve the opex objectives[90]
- a realistic expectation of the cost inputs required to achieve the opex objectives.[91]

In relation to United Energy, who did not propose a base year amount of opex, the AER is also not satisfied for the reasons discussed above that the opex proposed reasonably reflects the efficient costs that a prudent operator in the circumstances of United Energy would require to achieve the opex objectives, or a realistic expectation of the cost inputs required to achieve the opex objectives.[92]

The AER has therefore estimated the required base year opex for each DNSP, and has made the minimum adjustments necessary (as discussed in this chapter) to their base opex proposals.[93] The AER considers the adjusted base year opex forecasts reasonably reflect the opex criteria. The AER's conclusions on each Victorian DNSP's base year opex are summarised in the Table 7.12 below.

89 Clauses 6.5.6(e)(1),(3),(5),(9) of the NER
90 Clause 6.5.6(c)(1),(2) of the NER.
91 Clause 6.5.6(c)(3) of the NER.
92 Clause 6.5.6(c) of the NER.
93 Clause 6.12.3(f)(2) of the NER.

Table 7.12 AER conclusion on adjustments to 2009 base year opex ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Reported base opex	36.6	126.6	51.1	141.0	93.6
Related party margins	–	–	–	–0.03	–
ACS adjustments	–	–	0.2	–	–
Movement in provisions	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	–
Distribution licence fees	–0.2	–0.3	0.1	–0.3	–
GSL payments	–0.002	–1.8	–0.02	–6.8	–0.1
Costs not verified by auditors[a]	–	–	–	–	[c-i-c]
Exclusion of management fees	–	–	[c-i-c]	–	[c-i-c]
Exclusion of corporate strategy costs	–	–	[c-i-c]	–	[c-i-c]
Non-recurrent expenditure	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
2010 efficiency adjustment	0.6	4.3	1.6	3.6	2.1
Final decision base opex	**37.1**	**129.6**	**46.3**	**120.1**	**92.2**

Source: AER analysis.
[a]This reflects an adjustment for United Energy/PIE's cost in Appendix I.

7.5.4 Scale escalation

The AER recognises that as distribution networks grow in size, intuitively the distribution businesses will face an increase in the costs of operating and maintaining their networks. Scale escalation is typically expressed in terms of an annual rate of growth in opex resulting from the increase in the size of the distribution network. The annual growth rate of the network is determined with reference to network growth drivers that are considered to approximate the resultant growth in the network and hence, opex. The annual growth rate is used to escalate base opex and is then adjusted downwards to reflect identified economies of scale. The efficiency savings from economies of scale accrue to the DNSP (and in turn customers) because the cost per unit of operating and maintenance activities falls as the scale of network operating and maintenance activities increases because these activities can be conducted more efficiently.

This section presents an overview of the Victorian DNSPs' revised proposals and the AER's considerations and conclusions with respect to scale escalation. The AER's detailed assessment of the Victorian DNSPs' revised scale escalation proposals is discussed in appendix J.

7.5.4.1 AER draft decision

In the draft decision, the AER considered the information included in and accompanying each of the Victorian DNSPs' building block proposals as required by clause 6.5.6(e)(1) of the NER. The AER considered that the growth drivers and adjustments for economies of scale efficiencies proposed by the Victorian DNSPs did not result in an approximation of network growth that reasonably reflected a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[94] In particular, the AER considered that the Victorian DNSPs' proposed scale opex was not appropriate to meet or manage the expected demand for standard control services over the forthcoming regulatory control period, as required by clause 6.5.6(a)(1) of the NER. The AER's draft decision on scale escalation is displayed in Table 7.13.

Table 7.13 AER draft decision on scale escalation opex (per cent, per annum)

	Gross growth rate	Economies of scale adjustment	Capex/opex trade-off	Net growth rate	Draft decision scale opex ($m, 2010)
CitiPower	1.0	53.3	16.5	0.3	**1.4**
Powercor	1.4	57.1	8.0	0.5	**8.8**
JEN	1.1	57.6	7.2	0.4	**2.5**
SP AusNet	1.5	62.5	5.7	0.5	**8.4**
United Energy	1.0	57.6	4.6	0.4	**4.6**

Source: AER draft decision, appendix J, pp. 105, 109; draft decision models.

94 NER, cl. 6.5.6(c)(3).

7.5.4.2 Victorian DNSP revised regulatory proposals

Each of the Victorian DNSPs except for United Energy applied an explicit escalation to its revised base opex proposal for growth in the size of the distribution network. United Energy provided the AER with growth drivers and net growth rates, but reiterated that the tender process for outsourced services addresses unit prices and volumes.[95]

The Victorian DNSPs apart from SP AusNet generally accepted the AER's draft decision regarding the selection of scale escalation growth drivers, but considered that zone substation capacity was a more appropriate driver than the number of zone substations. SP AusNet disagreed with the draft decision network growth driver for the number of distribution transformers, the use of the number zone substations, and the use of a simple average weighting of the network growth drivers.[96]

In general, the Victorian DNSPs did not accept the majority of the AER's draft decision on the adjustments to the growth rates for economies of scale and opex associated with the trade off between capex and opex. The Victorian DNSPs' revised scale escalation proposals are summarised in Table 7.14.

Table 7.14 Victorian DNSP revised proposals on scale escalation opex (per cent, per annum)

	Gross growth rate	Economies of scale[b]	Net growth rate	Revised scale opex ($'m, 2010)
CitiPower[a]	2.3	42.9	1.3	**6.7**
Powercor[a]	2.3	32.3	1.5	**28.7**
JEN[c]	2.4	57.6	1.0	**8.4**
SP AusNet[d]	2.0	43.6	1.1	**20.7**
United Energy[e]	–	–	0.8	**–**

Source: AER analysis of Victorian DNSPs' revised regulatory proposals, Victorian DNSPs' RINs, and Victorian DNSPs' cost escalation models.
[a]CitiPower and Powercor's proposed scale opex increases are slightly different to their revised proposals as data for these two businesses were resubmitted in response to a request for further information by the AER. Their growth rates have been adjusted to remove the effects of input cost escalation.
[b]CitiPower and Powercor's economies of scale factors were calculated by the AER and JEN's is based on conditional acceptance of draft decision.
[c]Although JEN applies an overall average annual net growth rate of 0.95 per cent in its forecast data model, the effective net growth rate (calculated as the average annual rate growth from 2010 to 2015) is closer to 3.0 per cent. JEN's intention is to apply the 'customer number' growth driver to opex and the 'network growth' driver to maintenance expenditure, but its forecast data model appears to apply a network growth driver to opex and maintenance.
[d]SP AusNet's total growth rates and economies of scale are calculated on the basis that scale escalation is applied to maintenance expenditure only.

95 United Energy, Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015, July 2010, pp. 81–83.

96 SP AusNet, Electricity Distribution Price Review, *Revised regulatory proposal,* July 2010, pp. 194–195.

[e]Although United Energy's opex forecast is not based on the 'year 4' roll forward model, United Energy provided a net growth rate in its revised proposal (p. 83).

7.5.4.3 Submissions

The AER received submissions on scale escalation from the Energy Users Association of Australia, the Energy Users Coalition of Victoria and EnergyAustralia on the AER's approach to scale escalation, including the AER's selection of growth drivers. Some of the submissions relating to growth drivers were:

- The EUCV submitted that great care must be taken to ensure that any growth driver replicates the actual organic growth of the network occasioned by geographical expansion, and the impact of new replacement assets is reflected by a reduction of opex.[97]

- The EUAA submitted that the AER's adopted growth drivers do not adequately take opex increases due to customer density growth into consideration. The EUAA submitted this is especially important for those businesses whose regions will experience increasing customer density rather than extensions of the network.[98]

7.5.4.4 Consultant review

In assessing the Victorian DNSPs' proposed scale escalation, the AER engaged Nuttall Consulting to review and make recommendations on the AER's approach to scale escalation, including the appropriateness of the network growth drivers, and the application of these drivers. Nuttall Consulting also reviewed the DNSPs' forecasts for these network growth drivers to assist the AER in assessing whether the Victorian DNSPs' revised proposals for scale escalation reasonably reflect the opex criteria in clause 6.5.6(c) of the NER.

7.5.4.5 Issues and AER considerations

Growth drivers

In the draft decision, the AER adopted the following growth drivers:

- a composite network growth driver calculated as a simple average of the annual growth in line length and the number of distribution transformers and zone substations over the forthcoming regulatory control period

- the annual growth in customer numbers over the forthcoming regulatory control period.

As discussed in appendix J, for this final decision the AER modified the composite network growth driver, substituting growth in zone substation capacity for growth in the number of zone substations. The AER maintained the simple average weighting for the composite network growth driver. The AER considers the drivers applied in this final decision will result in total forecast opex that reasonably reflects a realistic

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97 EUCV, Submission to the AER, August 2010, pp. 39–40.

98 Energy Users Association of Australia (EUAA), Submission to the AER - AER Draft Determination on Victorian electricity distribution prices for the period 2011-2015 and distributors revised proposals,19 August 2010, p. 35.

expectation of the demand forecast and cost inputs required to achieve the opex objectives[99] because they provide the most appropriate approximation of actual network growth.

Growth driver forecasts

The AER did not accept the Victorian DNSPs' revised growth forecasts for the components of the composite network growth driver after analysis identified unexplained inconsistencies between initial and revised proposals, as well as historical growth rates. The AER applied growth rates derived from historical data on the basis that they were more likely to result in total forecast opex that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives as required by clause 6.5.6(c)(3) of the NER. This is discussed in detail in appendix J.

The AER's adjustments to the gross growth rates of the Victorian DNSPs are displayed in Table 7.15.

Table 7.15 AER variation to Victorian DNSPs' proposed gross growth rates (per cent per annum)

	DNSP proposed gross growth rates	AER variation	AER gross growth rates
CitiPower	2.3	–0.8	1.5
Powercor	2.3	–0.5	1.8
JEN	2.4	–0.9	1.5
SP AusNet	2.0	–0.1	1.9
United Energy	–	–	0.9

Source: AER analysis

Allocation of growth drivers to operating and maintenance activities

In the draft decision, the AER allocated the composite network growth driver to all maintenance expenditure categories in the RIN and to the 'network operating' and 'other network operating' operating expenditure categories. The AER allocated the customer number growth driver to the remaining operating expenditure categories. In this final decision, the AER has applied the customer number growth driver to all operating expenditure categories, and the composite network growth driver to all maintenance expenditure categories based on issues raised in JEN's revised proposal. This is discussed further in appendix J.

Adjustments to gross growth rates

Consistent with the draft decision, the AER adjusted the DNSPs' gross growth rates for efficiencies arising from economies of scale.

However, the AER removed the adjustment for the effects of the capex/opex trade off following new information from the Victorian DNSPs which supported the view that

99 NER, cl. 6.5.6(c)(3).

base year opex is likely to be a reasonable approximation of the required level of opex to maintain the existing asset base.

The adjustments to the Victorian DNSPs' gross growth rates are discussed in detail in appendix J, and are summarised in Table 7.16.

Table 7.16 AER conclusion on net growth rates (per cent, per annum)

	Gross Growth Rate			Economies of scale			Net Growth Rate[a]		
	Opex	**Maint**	**Total**	**Opex**	**Maint**	**Total**	**Opex**	**Maint**	**Total**
CitiPower	1.7	1.2	**1.5**	72.8	25.1	**52.8**	0.5	0.9	**0.7**
Powercor	1.9	1.8	**1.8**	73.0	35.9	**50.2**	0.5	1.1	**0.9**
JEN	1.5	1.4	**1.5**	72.9	33.8	**63.7**	0.4	0.9	**0.5**
SP AusNet	1.7	2.1	**1.9**	100.0	40.3	**68.7**	0.0	1.3	**0.6**
United Energy	0.8	1.3	**0.9**	72.9	33.8	**62.1**	0.2	0.9	**0.3**

Source: AER analysis.
[a]Net growth rate = gross growth rate x (1 – economies of scale)

The AER's final scale escalation opex allowances are displayed in Table 7.17.

Table 7.17 AER conclusion on scale escalation opex ($'m, 2010)

	2011	**2012**	**2013**	**2014**	**2015**	**Total[a]**
CitiPower	0.3	0.5	0.8	1.0	1.3	**3.9**
Powercor	1.2	2.3	3.5	4.7	5.9	**17.7**
JEN	0.3	0.5	0.8	1.0	1.3	**3.8**
SP AusNet	0.7	1.4	2.1	2.9	3.6	**10.8**
United Energy	0.3	0.6	1.0	1.3	1.6	**4.8**

Source: AER analysis
[a]Totals may not add due to rounding.

7.5.4.6 AER conclusion

For the reasons outlined above and discussed in appendix J, the AER is not satisfied that the Victorian DNSPs' revised scale escalation proposals would result in total opex forecasts that reasonably reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives, as required by clause 6.5.6(c)(3) of the NER. In particular, the AER does not consider the Victorian DNSPs' revised scale escalation proposals are consistent with the requirement to 'meet or manage' the expected demand for standard control services over the forthcoming regulatory control period, pursuant to clause 6.5.6(a)(1) of the NER. As required by clause 6.5.6(e) of the NER, the AER has had regard to the opex factors in reaching its conclusion. The opex factors relevant to the AER's assessment of scale escalation are factors (1) to (5), and to a lesser extent, (6) and (7).

7.5.5 Real cost escalation

7.5.5.1 AER draft decision

The AER was not satisfied that the real escalation rates proposed by the Victorian DNSPs reasonably reflected a realistic expectation of the cost inputs required to achieve the opex (and capex) objectives.[100]

Specifically, in relation to non-labour escalation, although the AER considered the proposed approaches were broadly consistent with past AER decisions, the AER was not satisfied that (among other things) the approach to exchange rate forecasting and the inclusion of an allowance for the carbon pollution reduction scheme reasonably reflected a realistic expectation of cost inputs.[101]

In relation to labour escalation, the AER did not accept the methodologies used to develop the real labour cost escalators within the Victorian DNSPs' regulatory proposals.[102]

7.5.5.2 Victorian DNSP revised proposals

Consistent with their initial regulatory proposals, the Victorian DNSPs in their revised regulatory proposals applied real cost escalation to their opex allowances to account for expected real input cost increases. The AER's detailed consideration of non-labour and labour real cost escalation is discussed in appendix K.

In assessing the opex allowances proposed by the Victorian DNSPs, the AER considered the level of efficient expenditure required for both labour and non-labour inputs that a prudent operator, in the actual circumstances of each DNSP, would require based on a realistic expectation of the cost inputs required to achieve the opex objectives.

The AER considers that the following opex factors are particularly relevant to this assessment:

- the information included in and accompanying the Victorian DNSPs proposals
- submissions received in the course of consulting on the Victorian DNSPs proposals
- analysis undertaken for the AER by Access Economics and by the AER that was published before this distribution determination was made in its final form
- the actual and expected opex of the Victorian DNSPs during preceding regulatory control periods
- the relative prices of operating and capital inputs.[103]

[100] Clauses 6.5.6(c)(3), 6.5.7(c)(3) of the NER.
[101] AER, *Draft decision, Appendix K.*
[102] AER, *Draft decision, Appendix K.*

7.5.5.3 Submissions

The AER received submissions regarding the escalation of labour and materials costs for forecast real price movements from EnergyAustralia and EUCV.

EnergyAustralia stated that the AER’s decisions should be subject to the same transparent process as applied to submissions and should make its cost escalation model available, with any confidential information removed as necessary.[104]

The EUCV acknowledged that the AER's application of real cost escalators attempts to recognise the costs the Victorian DNSPs will incur over time. The EUCV, however, considered that the real cost escalators have proven to be uniformly wrong and have introduced a conservatism into allowances that consumers have had to pay for.[105]

The EUCV proposed two different approaches to the escalation of real cost increases:

- escalating by CPI only, or
- using an 'energy industry inflation adjustor' in the control mechanism rather than CPI.[106]

EnergyAustralia stated that since the AER's final determination for EnergyAustralia, it has entered into a supply contract for financial year 2009 that increased its wood pole costs by 6 per cent. The key drivers for this cost increase were royalty, labour and chemical cost increases. EnergyAustralia stated that if the Victorian DNSPs purchase wood poles at the same cost, then escalating the Victorian DNSPs' wood pole costs by CPI will not adequately cover wood pole price increases.[107]

The EUCV expressed concern over the accuracy of the exchange rate forecasts adopted by the AER. It stated that the forecasts have shown extreme volatility and were likely to be incorrect later in a regulatory period, providing either a large benefit or detriment to the Victorian DNSPs over a five year regulatory control period. The EUCV also considered that the forecasts used by the AER were biased to conservatism. [108]

The EUCV noted that the AER's draft decision supported the application of Access Economics' productivity impacts in the modelling of its wage cost growth forecasts. However, the EUCV highlighted that the AER instead applied Access Economics' labour price aggregates without productivity adjustments.[109]

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103 Clauses 6.5.6(e)(1), 6.5.6(e)(2), 6.5.6(e)(3), 6.5.6(e)(5) and 6.5.6(e)(6) of the NER.

104 EnergyAustralia, *EnergyAustralia submission on AER draft regulatory determination for Victorian distributors*, 19 August 2010, p.7.

105 Energy Users Coalition of Victoria, *Submission to the AER - 2010 AER review of Victorian Electricity DBs, EUCV response to AER Draft Decision*, August 2010, p. 24.

106 EUCV, *Submission to the AER*, 19 August 2010, pp. 24–25.

107 EnergyAustralia, *Submission to the AER*, 19 August 201, pp. 7–8.

108 EUCV, *Submission to the AER*, 19 August 2010, pp. 25–26.

109 EUCV, *Submission to the AER*, 19 August 2010, p. 29.

The EUCV also added that previous ESCV decisions, and those of other regulators, inserted specific productivity gains into the capex and opex forecasts for labour inputs.[110]

EnergyAustralia noted that should the AER not apply EGW escalation rates to clerical staff, which 'may be appropriate', the AER should further investigate how the EGW index is actually collated.[111]

7.5.5.4 Consultant review

In response to the Victorian DNSPs' revised regulatory proposals, the AER engaged Access Economics to update its March 2010 labour cost forecasts.[112]

7.5.5.5 Issues and AER considerations

For the reasons discussed above and in appendix K, the AER is not satisfied that the Victorian DNSPs' opex proposals reasonably reflect the opex criteria. Accordingly, the AER has substituted the Victorian DNSPs' opex proposals using the real input cost escalation rates in table 7.18. The AER considers that these rates reflect the minimum adjustment necessary in order for the AER to be satisfied that the Victorian DNSPs opex allowances reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives.[113]

The AER notes that the real cost escalation rates in table 7.18 are lower than those proposed by the Victorian DNSPs. The primary driver of this difference is the AER's consideration that labour cost escalators should be based on a labour price index (LPI), as opposed to the Victorian DNSPs' proposals to utilise average weekly ordinary time earnings (AWOTE). Additionally, the forecasts utilised by the AER reflect inputs that are sourced from more recent data than that inherent in the Victorian DNSPs' revised regulatory proposals. These issues are discussed in detail in appendix K.

Table 7.18 AER conclusion on weighted opex real cost escalation rates (per cent)

	2011	2012	2013	2014	2015
CitiPower	0.8	2.4	4.3	6.8	8.4
Powercor	0.9	2.4	4.4	7.1	8.8
JEN	1.1	2.2	3.6	5.5	6.9
SP AusNet	0.6	2.1	3.9	6.2	7.4
United Energy	0.8	2.2	4.1	6.5	7.9

Source: AER analysis.

110 EUCV, *Submission to the AER*, 19 August 2010, p. 29.
111 EnergyAustralia, *Submission to the AER*, 19 August 2010, p. 8.
112 Access Economics, *Forecast growth in labour costs: update of March 2010 report*, 13 September 2010.
113 Clause 6.5.6(c)(3) of the NER.

7.5.5.6 AER conclusion

For the reasons discussed above, and in detail in appendix K, the AER considers its estimates in table 7.19 are consistent with a total forecast opex that reasonably reflects the opex criteria, and in particular reasonably reflect a realistic expectation of the cost inputs required to achieve the operating expenditure objectives. These estimates reflect the application of the weighted opex escalation rates in table 7.18 to approved base opex, escalated for scale increases.

Table 7.19 AER conclusion on opex real cost increases ($’000, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	313	893	1624	2595	3244	**8668**
Powercor	1179	3206	5907	9541	11 877	**31 710**
JEN	520	1033	1685	2627	3296	**9160**
SP AusNet	753	2516	4825	7588	9199	**24 881**
United Energy	746	2088	3830	6061	7444	**20 169**

Source: AER analysis

7.5.6 Step changes

Having determined the base operating and maintenance expenditure the AER’s approach is to recognise that DNSPs may be subject to changes in regulatory obligations or its operating environment, which would not necessarily be reflected in the recurrent expenditure. The base operating and maintenance expenditure should therefore be adjusted for costs arising from new (or removed) legislative obligations or requirements or changes in the Victorian DNSPs' operating environment (termed ‘step changes’). For these purposes, the reference to legislative obligations is intended to encompass all regulatory obligations whether imposed by legislation or another regulatory instrument, such as a licence, code or price determination.

Accordingly, the Victorian DNSPs should identify any step changes and provide information supporting the basis and quantum of these step changes. The opex criteria also require that the total of the forecast opex reasonably reflects efficient costs a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives.[114]

This section presents an overview of the Victorian DNSPs' revised proposals and the AER's considerations and conclusions with respect to step changes. The AER’s detailed assessment of the Victorian DNSPs' scale escalation revised proposals is discussed in appendix L.

7.5.6.1 AER draft decision

In the draft decision the AER largely rejected the Victorian DNSPs proposed step changes on the grounds that they were not supported by changes to regulatory obligations or did not reflect changes in the DNSPs' operating environment from the

[114] NER, cl. 6.5.6(c)(1), (2).

current regulatory period. In its draft decision the AER approved step changes totalling $44.5 million ($2010) of a total of $299 million ($2010) proposed by the DNSPs.

7.5.6.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs' revised regulatory proposals contended that the AER had applied an overly narrow interpretation of an opex step change and had not been consistent with its stated framework that a step change could arise from additional costs relating to new or removed regulatory obligations or requirements or changes in the operating environment.

Further, the Victorian DNSPs stated that the AER had applied the step change criteria across jurisdictions inconsistently, erroneously applied the NEL and the NER and inconsistently applied step change criteria throughout the draft decision.

Both CitiPower and Powercor did not agree with the opex step changes of $6.0 million ($2010) and –$8.1 million ($2010) respectively determined in the AER's draft decision.[115] They proposed step changes of $36.9 million ($2010) and $133.1 million ($2010) for the forthcoming regulatory control period.[116] Both CitiPower and Powercor incorporated the AER's draft decision on step changes for:

- regulatory submission costs
- self insurance
- climate change
- Electricity Safety (Management) Regulations 2009
- national framework for distribution network planning and expansion
- customer charter.[117]

However, they did not agree with the AER's draft decision for step changes relating to:

- insurance
- Electricity Safety (Electric Line Clearance) Regulations 2010
- at risk townships project (Powercor only)
- West Melbourne terminal station demand management program (CitiPower only).[118]

[115] CitiPower, *Revised regulatory proposal*, pp. 38–39, 162–202; Powercor, *Revised regulatory proposal*, pp. 38–39, 162–202.
[116] CitiPower, *Revised regulatory proposal*, p. 210; Powercor, *Revised regulatory proposal*, p. 200.
[117] CitiPower, *Revised regulatory proposal*, p. 177; Powercor, *Revised regulatory proposal*, pp. 166–167.

Further, CitiPower and Powercor raised the issue that the AER had not considered their proposed step change for communications in extreme supply events in the AER's draft decision.[119]

In addition, CitiPower and Powercor proposed five additional step changes in their respective revised proposals that they claimed have arisen since their initial proposal or have arisen out of the AER's draft decision.[120]

JEN did not agree with the allowance of $10.7 million ($2010) in the AER's draft decision for opex step changes.[121] JEN forecast an allowance of $48.7 million ($2010) for the forthcoming regulatory control period in its revised regulatory proposal.[122] JEN stated that its revised proposal reflects the acceptance of the AER's draft decision for some step changes, revised forecasts against other step changes[123] and proposed costs for two new step changes on tariff reassignment and annual monitoring and compliance reporting.[124]

SP AusNet did not agree with the allowance of $25.0 million ($2010) in the AER's draft decision for opex step changes.[125] SP AusNet's revised regulatory proposal forecast an allowance of $253.0 million ($2010) for the forthcoming regulatory control period.[126]

SP AusNet incorporated the AER's draft decision on step changes for increased bushfire insurance, climate change and its private overhead electric line (POEL) inspection program. However, SP AusNet did not agree with the AER's draft decision on the remaining opex step changes. In addition, SP AusNet proposed eight additional step changes in its revised regulatory proposal which it claimed have either been updated with more up to date information, arisen since its initial proposal or have arisen out of the AER's draft decision.[127]

United Energy did not agree with the allowance of $10.9 million ($2010) in the AER's draft decision for opex step changes.[128] United Energy's revised regulatory proposal forecast an allowance of $83.1 million ($2010) for the forthcoming regulatory control period.[129]

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118 CitiPower, *Revised regulatory proposal*, pp. 178, 189–202; Powercor, *Revised regulatory proposal*, pp. 167, 179–191.

119 CitiPower, *Revised regulatory proposal*, pp. 203–204; Powercor, *Revised regulatory proposal*, pp. 168, 192–195.

120 CitiPower, *Revised regulatory proposal 2011–1*5, 21 July 2010, pp. 41, 174, 178, 186–189, 204–209; Powercor, *Revised regulatory proposal 2011–15*, 21 July 2010, pp. 39, 162–163, 168, 176–178, 193–197.

121 JEN, *Revised regulatory proposal*, pp. 116–117; JEN, *Revised regulatory proposal*, Appendix 7.2, 20 July 2010.

122 JEN, *Revised regulatory proposal*, 21 July 2010, p. 116.

123 JEN, *Revised regulatory proposal*, 21 July 2010, p. 116.

124 JEN, *Revised regulatory proposal*, Appendix 7.2, pp. 71–74.

125 SP AusNet, *Revised regulatory proposal*, pp. 200–256.

126 SP AusNet, *Revised regulatory proposal*, p. 256.

127 SP AusNet, *Revised regulatory proposal*, p. 256.

128 United Energy, *Revised regulatory proposal*, pp. 85–96.

129 United Energy, *Revised regulatory proposal*, p. 96.

United Energy incorporated the AER's draft decision for step changes relating to an insurance premium increase and RIT-D requirements as well as providing a revised allowance for the step change relating to line clearances.[130]

United Energy did not agree with the AER's draft decision on the remaining opex step changes. As with the majority of the other Victorian DNSPs, United Energy also proposed two new opex step changes relating to tariff reassignment requirements and annual monitoring and compliance reporting. [131]

7.5.6.3 Submissions

The following stakeholders submitted comments in relation to step changes, including:

- Energy Response, which considered that the Victorian DNSPs' proposed demand management step changes represented a reasonable first step towards exploring the potential of demand side response and other non-network solutions[132]
- EnergyAustralia, who considered that the AER had applied criteria in the assessment of opex step changes that do not reflect the opex criteria in the NER, and had rejected expenditure that would otherwise satisfy the criteria[133]
- EziKey Group, trading as WireAlert, in support of JEN's proposed step change to implement a pilot trial of neutral condition monitors[134]
- Grid Australia, who considered that the AER had applied criteria for the approval of opex step changes that were too narrow to deliver efficient costs[135]
- JEN, which noted that it was reviewing its forecast opex step change for compliance with new electricity safety regulations[136]
- Total Environment Centre, which considered that the AER failed to adequately assess the Victorian DNSPs' proposed non-network alternative step changes[137]
- Visy, which considered that the AER was correct to only accept clearly defined opex step changes.[138]

7.5.6.4 Consultant review

The AER engaged Nuttall Consulting to review the following step changes.

- Electricity Safety (Electric Line Clearance) Regulations

130 United Energy, *Revised regulatory proposal*, pp. 89, 90, 95.
131 United Energy, *Revised regulatory proposal*, p. 95.
132 Energy Response, Submission, 17 August, 2010.
133 EnergyAustralia, Submission, 19 August 2010 , pp. 14–16.
134 EziKey Group Pty Ltd, *Submission to the Victorian electricity distribution 2011–2015 price review: Responding to the draft Jemena Electricity Networks (Victoria) Ltd distribution determination 2011–2015*, August 2010.
135 Grid Australia, Submission, 19 August 2010,
136 JEN, Submission, 19 August 2010,
137 Total Environment Centre, Submission, 24 August 2010, pp. 3–4.
138 Visy, Submission, 19 August 2010, pp. 2–3.

- West Melbourne terminal station (CitiPower)
- 'at risk township' protection plans (Powercor)
- IT opex (JEN and SP AusNet)
- capex/opex balance (JEN)
- power cable test program (SP AusNet)
- condition monitoring (SP AusNet)
- power transformer refurbishment (SP AusNet)
- substation earthing systems (SP AusNet)
- substation site cleanup (SP AusNet)
- substation civil infrastructure works (SP AusNet)
- substation fire systems (SP AusNet)
- process and configuration management (SP AusNet)
- quality of supply (SP AusNet)
- demand management initiatives (SP AusNet and United Energy)
- zone substation power quality metering maintenance (United Energy)
- zone substation secondary spares maintenance (United Energy)
- annual monitoring and compliance reporting (CitiPower, Powercor, JEN and United Energy).

7.5.6.5 Issues and AER considerations

This AER assessed the proposed allowance and the level of efficient expenditure for operating expenditure step changes which a prudent operator, in the actual circumstances of each DNSP, would be required to incur based on a realistic expectation of the demand forecast and the cost inputs required to achieve the operating expenditure objectives.

In assessing all step changes, the AER excluded real cost escalation when coming to its final decision, but the final numbers in Table 7.20 are inclusive of real cost escalation.

The AER took into account advice from Energy Safe Victoria (ESV) as to the nature and extent of environmental safety obligations the Victorian DNSPs would be required to meet over the 2011–15 regulatory control period. Specifically, ESV advised on the volume of work required to meet safety obligations, which the AER largely accepted. The AER then compared the Victorian DNSPs' proposed unit costs to undertake this volume of work and reduced unit rates where insufficient evidence on unit rates was provided by the Victorian DNSPs.

The AER also had regard to ESV levies and fees likely to be payable by the Victorian DNSPs over the 2011–15 regulatory control period and has provided an opex step change allowance for these costs.

The AER assessed proposed compliance costs to meet various government obligations, including national reporting of greenhouse emissions, the soon to be implemented regulatory investment test for distribution, compliance with the updated Electricity Distribution Code, and regulatory submission costs.

In many cases, the Victorian DNSPs disputed the AER's draft decision on these issues and proposed revised step change opex to meet their various obligations. The AER had regard to the level of base opex in 2009, updated DNSP forecasts and the nature of the obligations, including the additional requirements that the Victorian DNSPs would need to meet over the 2011–15 regulatory control period.

Finally, the AER considered the additional expenditure proposed by the Victorian DNSPs in relation to leveraging AMI data, information technology costs, introducing innovative tariffs and other DNSP specific step changes. In many cases, the AER has accepted that additional step change expenditure will be required for these activities in order for the Victorian DNSPs to meet the opex objectives.

7.5.6.6 AER conclusion

The increase from $44.5 million ($2010) approved in the draft decision to $393.6 million ($2010) in the final decision is made up mainly from opex step changes due to electricity safety obligations ($206.3 million), DNSP specific step changes ($33.1 million), insurance costs ($33.8 million), customer communications obligations ($19.3 million) and information technology costs ($41.2 million). The bulk of these therefore reflects new safety obligations by Energy Safe Victoria. These obligations are not a response to the Bushfire Royal Commission. New obligations arising from the Bushfire Royal Commission will be dealt with as pass throughs.

All step changes are discussed in further detail in appendix L.

Table 7.20 AER conclusion on step changes by year, all Victorian DNSPs, 2011–15 ($'m, 2010 including real cost escalation)

	2011	2012	2013	2014	2015	Total
CitiPower	6.5	5.7	5.9	4.1	4.2	26.4
Powercor	22.0	21.3	15.3	15.0	15.2	88.9
JEN	8.2	6.2	5.5	9.2	7.2	36.3
SP AusNet	30.0	34.3	37.0	42.2	42.3	185.9
United Energy	11.2	11.6	10.1	11.7	11.5	56.1
Total	**77.9**	**79.2**	**73.8**	**82.2**	**80.4**	**393.6**

7.5.7 Self insurance

Self insurance serves to provide allowances for the costs associated with risks that are not incurred in a consistent or predictable manner over time. The timing of these costs is often not known in advance, hence the service provider 'self insures' for them. For risks that have been historically incurred, the common method of calculating self insurance premiums is by undertaking a 'loss times probability' calculation.

The AER’s detailed assessment of the DNSPs' self insurance proposals is discussed in appendix M.

Part of the Victorian DNSPs’ revised regulatory proposals provided an allowance for self insurance.

7.5.7.1 AER draft decision

In assessing the Victorian DNSPs' self insurance proposals, the AER reviewed whether the forecast opex allowance was already included within the DNSPs' base year actual expenditure (see appendix M). The AER determined that for self insurance proposals relating to below deductible expenditure**,** certain proposals were not accepted on the basis that to allow such expenditure would double count the efficient level of below deductible costs in the base year opex allowance (see appendix M).

The AER's draft decision rejected all self insurance amounts for CitiPower, Powercor and SP AusNet. It permitted some property risks for JEN, and below deductible amounts for United Energy for asbestos liability.

7.5.7.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor and JEN accepted the AER's draft decision on self insurance, and incorporated the appropriate figures into their revised regulatory proposals.[139]

[139] CitiPower, *Revised regulatory proposal 2011 to 2015*, July 2010, p.33; JEN, *Revised regulatory proposal, July 2010*, pp. 124-125; Powercor, *Revised regulatory proposal 2011 to 2015*, July 2010, p. 167.

SP AusNet and United Energy did not accept the AER's draft decision on self insurance. SP AusNet provided updated calculations for liability risks, and maintained its position on poles and wires risk (from the initial regulatory proposal).[140] United Energy rejected the AER's positions on self insurance, and stated that it maintained the amounts put forward in its initial regulatory proposal.[141]

The Victorian DNSPs' revised regulatory proposals on self insurance are outlined in Table 7.21 to Table 7.25 below and discussed in detail in appendix M.

7.5.7.3 Submissions

No stakeholder submissions were received on self insurance.

7.5.7.4 Issues and AER considerations

The AER has assessed the Victorian DNSPs' self insurance proposals for the 2011–15 regulatory control period against the opex criteria, objectives and factors. Further discussion on the AER's considerations can be found in appendix M of this final decision.

7.5.7.5 AER conclusion

Noting that CitiPower, Powercor and JEN each accepted the AER's draft decision, the amounts for those DNSPs below reflect the AER's draft decision. SP AusNet and United Energy did not agree with the AER's draft decision. The figures below reflect the amounts proposed in those DNSPs revised regulatory proposals.

The AER approves the following self insurance amounts for the Victorian DNSPs over the 2011–2015 regulatory control period:

140 SP AusNet, *Revised regulatory proposal*, pp. 258-262.
141 United Energy, *Revised regulatory proposal*, pp. 98-99.

Table 7.21 AER's decision on CitiPower's self insurance allowance 2011 - 2015 ($m, 2010)

Risk	Initial regulatory proposal	AER decision
Liability	0	0
Motor vehicle	0	0
Property	0	0
Total	**0**	**0**

Table 7.22 AER's decision on Powercor's self insurance allowance 2011 - 2015 ($m, 2010)

Risk	Initial regulatory proposal	AER decision
Liability	0	0
Motor vehicle	0	0
Property	0	0
Total	**0**	**0**

Table 7.23 AER's decision on JEN's self insurance allowance 2011 - 2015 ($m, 2010)

Risk	Initial regulatory proposal	AER decision
Substations—catastrophic or component failure	0	0
Other assets—storms and lightning	0	0
Other assets—pole fires	0	0
Damage to third party property	0.167	0.167
Public liability—fatality	0.051	0.051
Public liability—injury	0.304	0.304
Total	**2.669**	**0.522**[a]

a) An allowance of $104 300 per year of the regulatory period

Table 7.24 AER's decision on SP AusNet's self insurance allowance 2011 - 2015 ($m, 2010)

Risk	Revised regulatory proposal	AER decision
Liability—general	9.8	0
Poles and wires	8.9	6.5
Insurer default	0	0
Fraud	0	0
Total	**18.7**	**6.5**

Table 7.25 AER's decision on United Energy's self insurance allowance 2011 - 2015 ($m, 2010)

Risk	Revised regulatory proposal	AER decision
Liability —general	0.535	0
Liability—fire	0.245	0
Liability—asbestos	0.120	0.12
Poles and wires	2.710	0
Fraud	0.015	0
Insurer's default	0.125	0
Property	13.750	0
Contaminated land	2.380	0
Environmental	0.220	0
Total	**20.030**	**0.12**[a]

(a) An allowance of $24 000 per year of the regulatory period.

7.5.8 Debt raising costs

Debt raising costs are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has accepted that debt raising costs are a legitimate expense for which a distribution network service provider (DNSP) should be provided an allowance.[142]

[142] AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Final decision, 14 June 2007, pp. 94–97; AER, *SP AusNet transmission determination 2008–09 to 2013–14*, Final decision, 31 January 2008, pp. 148–150; AER, *ElectraNet transmission determination 2008–09 to 2013–14*, Final decision, 11 April 2008, pp. 84–85; AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, 28 April 2009, pp. 183–188, 541–560 (appendix N).

Part of the Victorian DNSPs' revised forecast opex proposals provided an allowance for debt raising costs. Relevant to assessing and determining whether a DNSP's proposed forecast opex allowance for debt raising costs reasonably reflect the opex criteria are the opex factors, and for debt raising costs the AER has specifically had regard to benchmark opex that would be incurred by an efficient DNSP over the regulatory control period.[143]

The AER has assessed the benchmark debt raising costs of the Victorian DNSPs on this basis. Where consultant reports have been submitted by one of the Victorian DNSPs, to the extent that the information is pertinent to all Victorian DNSPs the information has been considered as applicable to all Victorian DNSPs within this section.

7.5.8.1 AER draft decision

The AER determined debt raising cost allowances for each of the Victorian DNSPs based on the refined Allen Consulting Group (ACG) benchmark debt raising cost method. These direct debt raising amounts (costs relating to underwriting fees, legal fees, company credit rating fees and other transaction costs) excluded indirect debt raising costs (underpricing) and additional early refinancing costs (costs for raising debt at least 3 months prior to refinancing maturing debt). The draft decision debt raising cost allowance and applicable basis points per annum (bppa) is outlined in Table 7.26.

Table 7.26 AER draft decision on debt raising cost allowances

DNSP	Basis points per annum	$'m, 2010
CitiPower	9.3	3.79
Powercor	9.1	6.30
JEN	9.8	2.21
SP AusNet	9.1	5.96
United Energy	9.3	3.96

Source: AER, *Draft decision*, pp. 269–270.

7.5.8.2 Victorian DNSP revised regulatory proposals

JEN and SP AusNet accepted the AER's draft decision on debt raising costs in their revised regulatory proposals.[144] CitiPower, Powercor and United Energy did not accept the AER's draft decision on debt raising costs.[145] The revised debt raising costs allowance proposed by the Victorian DNSPs are outlined in Table 7.27.

143 NER, clause 6.5.6(e)(4).
144 Jemena electricity networks (JEN), *Revised regulatory proposal 2011–15*, 20 July 2010, p. 125; SP AusNet, *Revised regulatory proposal 2011–15*, 20 July 2010, pp. 262–264.
145 CitiPower, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 173; Powercor, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 175; United Energy, *Revised regulatory proposal 2011–15*, July 2010, p. 99.

Table 7.27 Victorian DNSP revised proposal debt raising cost allowances ($'m, 2010)

DNSP	2011	2012	2013	2014	2015	Total
CitiPower	1.85	2.03	2.20	2.39	2.57	**11.04**
Powercor	3.19	3.48	3.77	4.04	4.32	**18.79**
JEN	0.44	0.48	0.53	0.56	0.59	**2.59**
SP AusNet	1.11	1.19	1.31	1.42	1.52	**6.55**
United Energy	0.75	0.82	0.88	0.93	0.95	**4.34**

Source: CitiPower, *Revised regulatory proposal*, p. 186; Powercor, *Revised regulatory proposal*, p. 175; JEN, *Post tax revenue model*; SP AusNet, *Revised PTRM*, p. 264; United Energy, *Post tax revenue model*.

In determining their respective revised direct debt raising costs, CitiPower, Powercor, JEN and SP AusNet have all accepted the AER's draft decision approach for approving or determining direct debt raising costs.[146] United Energy did not accept the AER's draft decision for direct debt raising costs and proposed 9.3 bppa as unit cost allowance in its revised regulatory proposal.[147]

In addition to the direct debt raising costs allowance, CitiPower and Powercor did not accept the AER's draft decision that early refinancing costs are included in the direct debt raising costs allowance as determined in the AER's draft decision.[148] Both CitiPower and Powercor proposed allowances for early refinancing costs of 15.5 bppa in addition to the allocated direct debt raising costs allowances.

7.5.8.3 Submissions

On 19 August 2010, in support of their revised regulatory proposals for early refinancing costs allowances CitiPower and Powercor provided a joint submission (CitiPower and Powercor submission) on the AER's draft decision for debt raising costs.[149]

This submission drew on a witness statement prepared by CitiPower's and Powercor's Chief Financial Officer (CFO's witness statement) which addressed early refinancing costs and contained confidential supporting information from third parties.[150]

On 7 October 2010 CitiPower and Powercor also provided an update to its submission (CitiPower and Powercor updated submission) to reflect updated proposals on debt raising costs based on their respective agreed averaging periods.[151]

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[146] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010, p. 3; JEN, *Revised regulatory proposal 2011–15*, 20 July 2010, p. 125; SP AusNet, *Revised regulatory proposal 2011–15*, 20 July 2010, pp. 262–264.

[147] United Energy, *Revised regulatory proposal 2011–15*, July 2010, p. 99; United Energy, *Post tax revenue model*.

[148] CitiPower, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 186; Powercor, *Revised regulatory proposal 2011–15*, 21 July 2010, p. 175.

[149] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs*, 19 August 2010.

[150] CitiPower & Powercor, *Submission on the AER's draft determination Appendix P: Debt raising costs: Statement of Julie Marie Williams*, 19 August 2010.

Although United Energy noted in its revised regulatory proposal that it intended to lodge a submission on debt raising costs, the AER notes a further submission was not provided.

7.5.8.4 Issues and AER considerations

Direct debt raising costs

The AER's detailed analysis and considerations of the Victorian DNSPs' proposed direct debt raising costs allowances are set out in appendix N. In summary, the AER considers that:

- Having considered the Victorian DNSPs' revised regulatory proposals, the AER remains satisfied that the ACG method is an appropriate tool for assessing whether the proposed forecast direct debt raising costs allowances is consistent with the requirement that the total forecast opex reasonably reflects the opex criteria or for determining a forecast for direct debt raising costs that is consistent with that requirement.[152]

- The AER has used recent updated transaction costs and updated the rolling five year window for bond data used to determine the direct debt raising costs, based on the five year period ending on the agreed averaging period, for the respective Victorian DNSPs

Based on this the AER has been informed by the ACG method to approve or determine the direct debt raising cost allowance for the Victorian DNSPs. The direct debt raising cost allowance for the Victorian DNSPs is dependent on the number of standard sized debt issue required (based on the notional debt value of its RAB), and the nominal WACC applying to the respective Victorian DNSPs.

Table 7.28 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG method and the respective DNSPs' nominal WACC.

[151] CitiPower & Powercor, *Update to Powercor and CitiPower's AER submission entitled "Submission on the AER's draft distribution determination 2011–2015, Appendix P: Debt raising costs*, provided by email, 7 October 2010.

[152] NER, clauses 6.5.6(c), 6.5.6(e)(4) and 6.12.1(4).

Table 7.28 Final Decision direct debt raising costs with a nominal WACC range between 9.44 and 9.99 per cent

Fee	Explanation	1 issue	2 issues	4 issues	6 issues	10 issues
Amount raised ($'m, nominal)	Multiples of median term notes ($250m)	250	500	1000	1500	2500
Gross underwriting fee	Median gross underwriting spread, upfront per issue	7.14–7.31	7.14–7.31	7.14–7.31	7.14–7.31	7.14–7.31
Legal and roadshow	$115k upfront per issue	0.73–0.75	0.73–0.75	0.73–0.75	0.73–0.75	0.73–0.75
Company credit rating	$50k per annum	2.00	1.00	0.50	0.33	0.20
Issue credit rating	4 basis point up front per issue	0.63–0.65	0.63–0.65	0.63–0.65	0.63–0.65	0.63–0.65
Registry fees	$3.5k up front per issue	0.14	0.14	0.14	0.14	0.14
Paying fees	$4/$1 million per annum	0.04	0.04	0.04	0.04	0.04
Total	**Basis points per annum**	**10.7–10.9**	**9.7–9.9**	**9.2–9.4**	**9.0–9.2**	**8.9–9.1**

Source: AER analysis.
Note: The ranges reflect the DNSPs’ different averaging periods and WACC.

Early refinancing costs

The AER notes that the CitiPower and Powercor’s revised regulatory proposals were the only submissions for early refinancing costs. While SP AusNet proposed early refinancing costs in its initial regulatory proposal it accepted the AER's draft decision that based on the ACG method the benchmark debt raising costs allowance already includes the efficient and prudent costs of a refinancing plan.

The AER's detailed analysis and considerations of the Victorian DNSPs' proposed early refinancing costs allowances are set out in appendix N. In summary, the AER considers that:

- DNSPs should only be allowed the efficient and prudent costs required for a refinancing plan, which may include early refinancing activities
- in establishing the efficient and prudent debt raising cost allowances for network service providers, the AER is informed by the analysis in the ACG method
- the ACG report (which set out the ACG method) was a comprehensive investigation into debt raising costs and incorporates refinancing elements

- in assessing early refinancing costs, the AER's analysis included the Standard and Poor's approaches (completion, commitment and underwriting methods) as well as two alternative approaches (cash reserves and a committed bank loan facility) submitted by CitiPower and Powercor

- based on this analysis the underwriting volume only method remains the efficient and prudent approach

- the characteristics and costs of the underwriting volume only method are consistent with the underwriting component in the ACG method and therefore to include this additional allowance for early refinancing costs would be inefficient.

Therefore, the AER does not consider that the allowance proposed by CitiPower and Powercor associated with early refinancing costs should be added to the direct debt raising costs allowances. The AER considers that to do so would be double counting the costs of managing refinancing risk. The AER considers that based on the ACG method the benchmark debt raising costs allowance already includes the efficient and prudent costs of a refinancing plan including early refinancing costs through underwriting volume only and that no increase in these costs is required.

7.5.8.5 AER conclusion

The AER considers that the proposed bppa allowance assessed for JEN, SP AusNet and United Energy is consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast operating expenditure reasonably reflects the operating expenditure criteria. The AER considers that the proposed bppa allowance assessed for CitiPower and Powercor is not consistent with the requirement in clause 6.5.6(c) of the NER that the total forecast operating expenditure reasonably reflects the operating expenditure criteria and accordingly has substituted this estimate. This assessment is relevant to the constituent decision the AER must make under clause 6.12.1(3) and 6.12.1(4) of the NER, to either accept or to not accept each of the Victorian DNSPs’ total forecast operating expenditure.

As a result of the analysis of the Victorian DNSPs' revised regulatory proposals and submissions, the AER considers the debt raising allowances set out in Table 7.29, and discussed below; represent the efficient and prudent costs that a network service provider in the circumstances of the respective DNSPs would require in the forthcoming regulatory control period.

Table 7.29 AER conclusion of benchmark debt raising costs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	0.69	0.74	0.78	0.83	0.87	**3.91**
Powercor	1.16	1.24	1.32	1.39	1.46	**6.57**
JEN	0.44	0.46	0.48	0.50	0.52	**2.41**
SP AusNet	1.12	1.20	1.30	1.40	1.49	**6.49**
United Energy	0.74	0.80	0.85	0.88	0.90	**4.16**

Source: AER analysis.

CitiPower has an opening RAB of $1.29 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of CitiPower's opening RAB is approximately $772.4 million (nominal). Based on the refined ACG method, CitiPower will require around 4 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.2 basis points per annum for direct debt raising costs is a reasonable benchmark for CitiPower. This benchmark is multiplied by the debt component of CitiPower's opening RAB to provide an average allowance of $0.78 million per annum ($2010).

Powercor has an opening RAB of $2.21 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of Powercor's opening RAB is approximately $1.33 billion (nominal). Based on the refined ACG method, Powercor will require around 6 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.0 basis points per annum for direct debt raising costs is a reasonable benchmark for Powercor. This benchmark is multiplied by the debt component of Powercor's opening RAB to provide an average allowance of $1.31 million per annum ($2010).

JEN has an opening RAB of $757 million (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of JEN's opening RAB is approximately $454 million (nominal). Based on the refined ACG method, JEN will require around 2 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.9 basis points per annum for direct debt raising costs is a reasonable benchmark for JEN. This benchmark is multiplied by the debt component of JEN's opening RAB to provide an average allowance of $0.48 million per annum ($2010).

SP AusNet has an opening RAB of $2.07 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of SP AusNet's opening RAB is approximately $1.24 billion (nominal). Based on the refined ACG method, SP AusNet will require around 5 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.2 basis points per annum for direct debt raising costs is a reasonable benchmark for SP AusNet. This benchmark is multiplied by the debt component of SP AusNet's opening RAB to provide an average allowance of $1.30 million per annum ($2010).

United Energy has an opening RAB of $1.38 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of United Energy's opening RAB is approximately $828 million (nominal). Based on the refined ACG method, United Energy will require around 4 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.2 basis points per annum for direct debt raising costs is a reasonable benchmark for United Energy. This benchmark is multiplied by the debt component of United Energy's opening RAB to provide an average allowance of $0.83 million per annum ($2010).

7.6 AER conclusion

The AER has considered each of the Victorian DNSPs’ revised forecast opex proposals in accordance with the opex factors in clause 6.5.6(e) of the NER. For the reasons discussed in this chapter, the AER is not satisfied that each component of operating expenditure associated with the Victorian DNSPs' revised forecasts opex proposals forms a total opex forecast the reasonably reflects the opex criteria. In particular the AER considers the:

- proposed base year opex does not reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives[153]
- application of scale escalators does not reasonably reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives[154]
- application of real cost escalators does not reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives[155]
- proposed step changes do not reasonably reflect the efficient costs of a prudent operator in the circumstances of the Victorian DNSPs[156]
- proposed self insurance forecasts do not reasonably reflect the efficient costs of a prudent operator in the circumstances of the Victorian DNSPs [157]
- proposed debt raising costs do not reasonably reflect the efficient costs of a prudent operator in the circumstances of the Victorian DNSPs[158]
- proposed GSL payments do not reasonably reflect the efficient costs of a prudent operator in the circumstances of the Victorian DNSPs[159]

153 See section 7.5.3 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to the revealed cost approach, clause 6.5.6(e)(4) on the use of benchmarking and clause 6.5.6(e)(9) regarding related party contracts.

154 See section 7.5.4 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to actual and expected opex, clause 6.5.6(e)(6) on the relative prices of operating and capital inputs and clause 6.5.6(e)(7) regarding the substitution between capex and opex.

155 See section 7.5.5 for a discussion of the opex factors, including clause 6.5.6(e)(6) in relation to the relative prices of operating and capital inputs.

156 See section 7.5.6 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to actual and expected opex and clause 6.5.6(e)(7) regarding the substitution between capex and opex.

157 See section 7.5.7 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to actual and expected opex.

158 See section 7.5.8 for a discussion of the opex factors, including clause 6.5.6(e)(4) on the use of benchmarking.

Under clause 6.5.6(d) of the NER, the AER cannot accept a DNSP’s total proposed forecast opex if it is not satisfied that the total forecast opex reasonably reflects the opex criteria. Pursuant to clause 6.12.1(4) of the NER, the AER must set out an estimate of the required opex which it considers reasonably reflects the opex criteria.

After making the adjustments outlined in this chapter, the AER considers that a forecast opex allowance that reasonably reflects the opex criteria is $2 713.3 million ($2010) for the Victorian DNSPs. For each DNSP this equates to a forecast opex allowance of:

- CitiPower: $228.6 million ($2010)
- Powercor: $798.4 million ($2010)
- JEN: $284.0 million ($2010)
- SP AusNet: $855.1 million ($2010)
- United Energy: $547.5 million ($2010).

These estimates of the required opex for each Victorian DNSP:

- have been determined on the basis of the AER's assessment of the forecast opex proposals
- are the result of the minimum adjustments necessary to the forecast opex proposals which the AER is satisfied reasonably reflect the opex criteria.[160]

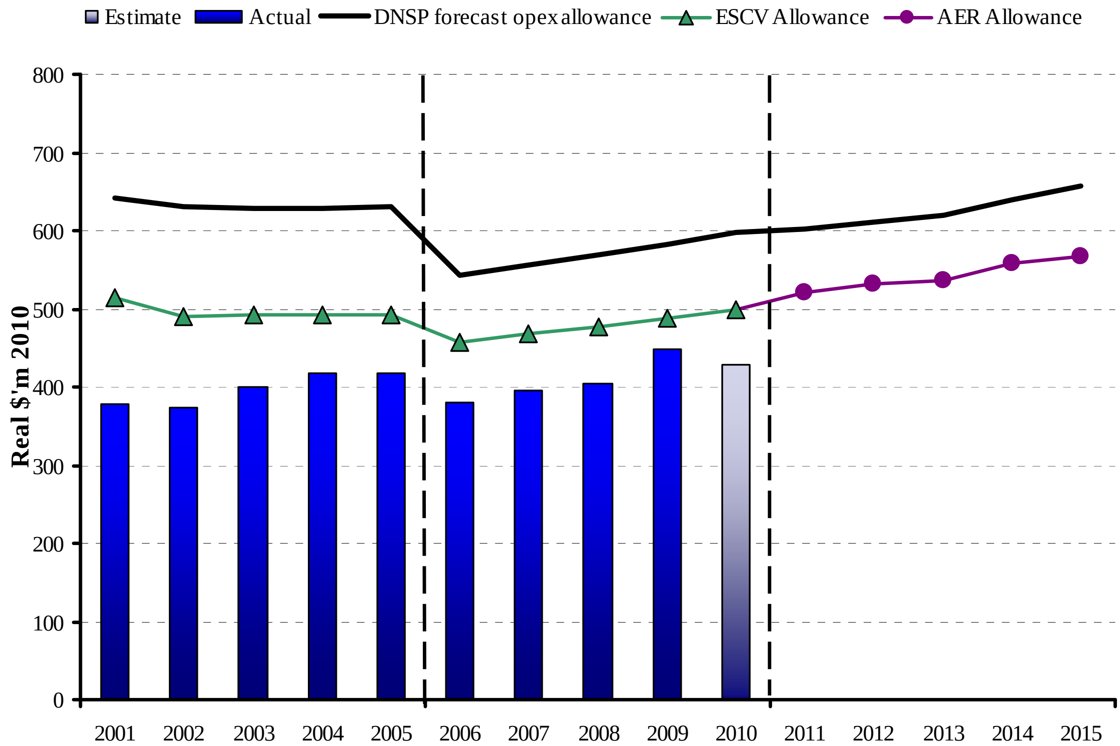
Figure 7.5 illustrates the AER’s final decision on the Victorian DNSPs’ forecast opex allowance of $3 130.7 million ($2010) compared to current and previous proposals, prior regulatory opex allowances and actual opex. Table 7.30 displays the AER’s final decision opex allowance for each DNSP.

The DNSPs' actual opex is represented by the blue bars in Figure 7.5. The DNSPs' current underspend relative to the ESCV regulatory opex allowance is denoted by the difference between the bars and the green patterned line between 2001 and 2010. The Victorian DNSPs' underspend relative to their own proposals is denoted by the difference between the bars and the solid line between 2001 and 2010. The AER's final decision opex allowance is denoted by the purple patterned line from 2011–15. The lightly shaded 2010 bar represents the Victorian DNSPs' estimated opex for 2010.

The AER's final decision opex allowance for the forthcoming regulatory control period is set at $2 713.6 million ($2010), which represents a reduction of $417.1 million, or 13 per cent from the Victorian DNSPs’ revised regulatory proposals (this broadly aligns with the DNSPs' expected underspend for the current regulatory control period).

159 See chapter 15 for a discussion on GSLs.
160 NER, cl. 6.12.3(f)(2).

Figure 7.5 AER final decision opex comparison for the Victorian DNSPs



Note: Actual figures are adjusted actuals as used in ECM calculation.

Table 7.30 AER final decision opex allowance for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
DNSP proposed opex	**265.7**	**926.6**	**340.8**	**960.1**	**637.5**	**3130.7**
AER opex build-up[a]						
AER base year costs	185.7	648.1	231.7	600.4	460.8	2126.7
AER scale escalation	3.9	17.7	3.8	10.8	4.8	41.0
AER real cost escalation	8.7	31.7	9.2	24.9	20.2	94.6
AER step changes[b]	26.4	88.9	36.3	185.9	56.1	393.6
AER debt raising costs	3.9	6.6	2.4	6.5	4.2	23.5
AER self insurance	–	–	0.5	6.5	0.1	7.1
AER other (GSL)	0.1	5.5	0.1	20.1	1.3	27.0
AER total opex	**228.6**	**798.4**	**284.0**	**855.1**	**547.5**	**2713.6**
Adjustment	**–37.1**	**–128.2**	**–56.8**	**–105.0**	**–90.0**	**–417.1**
Adjustment (per cent)	**–13.9**	**–13.8**	**–16.7**	**–10.9**	**–14.1**	**–13.3**

Source: AER analysis.
[a]Excludes DMIA allowance. [b]Includes real cost escalation.

An allowance of the $2 713.6 million ($2010) represents an increase of $523.3 million (24 per cent) from the draft decision allowance of $2 190.3 million ($2010) and $658.3 million (32 per cent) from the Victorian DNSPs' estimated actual opex in the current regulatory control period of $2 055.3 million ($2010).

Whilst the recommended expenditure outcomes can be seen as being reflective of past performance of the Victorian DNSPs, the opex allowance is also consistent with the current and prospective Victorian regulatory environment over the forthcoming regulatory control period according to the AER's assessment of associated cost drivers.

Under the revealed cost approach, the AER has determined an efficient level of base expenditure consistent with audited actual costs and a path of opex that is expected to remain relatively stable, with some increases due to new obligations. This level of expenditure is reflective of the continuity in regulatory outcomes and expectations. The decision, however, also incorporates continuing incentives for ongoing operating efficiency as well as maintenance and improvement in performance where this is valued by customers.

Since the release of the draft decision, the *Electricity Safety (Electric Line Clearance) Regulations 2010* have been finalised, which has resulted in an increase in opex costs for the Victorian DNSPs to comply with new safety obligations. Other new obligations and changes to the DNSPs' operating environments have resulted in increased opex allowances relating to IT, insurance, customer communications and some DNSP specific step changes. As stated in the draft decision, any legislated outcomes following the Victorian Bushfire Royal Commission (VBRC) may be treated as a pass through event, subject to the requirements of clause 6.6.1 of the NER.

The AER has continued to allow opex for the impact of network growth (scale escalation) including expected productivity improvements, and has allowed the value of the Victorian DNSPs' opex allowance to be maintained in real terms (incorporating changes in real input costs for labour and materials). Further, as noted in the draft decision, while it is too early to evaluate the precise effect on efficiency from the use of AMI, the AER expects that such efficiencies will be evident over time and will impact on operating cost trends over time. Through its annual reporting framework, the AER will be monitoring AMI impacts on operating costs.

Therefore, the AER considers that a total opex allowance of $2.7 billion over the forthcoming regulatory control period, an increase of around 32 per cent on actual levels in the current regulatory control period, is justifiable. This compares to revised proposed increases sought by the Victorian DNSPs of around 52 per cent.

For the reasons outlined in section 7.5, in accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept each of the Victorian DNSP's revised forecast opex proposals for the forthcoming regulatory control period. The AER is not satisfied that each Victorian DNSP's forecast opex, having regard to the opex factors, reasonably reflects the opex criteria in clause 6.5.6(c) of the NER. The AER has set out its approach to opex in the distribution determination documents for CitiPower, Powercor, JEN, SP AusNet and United Energy.

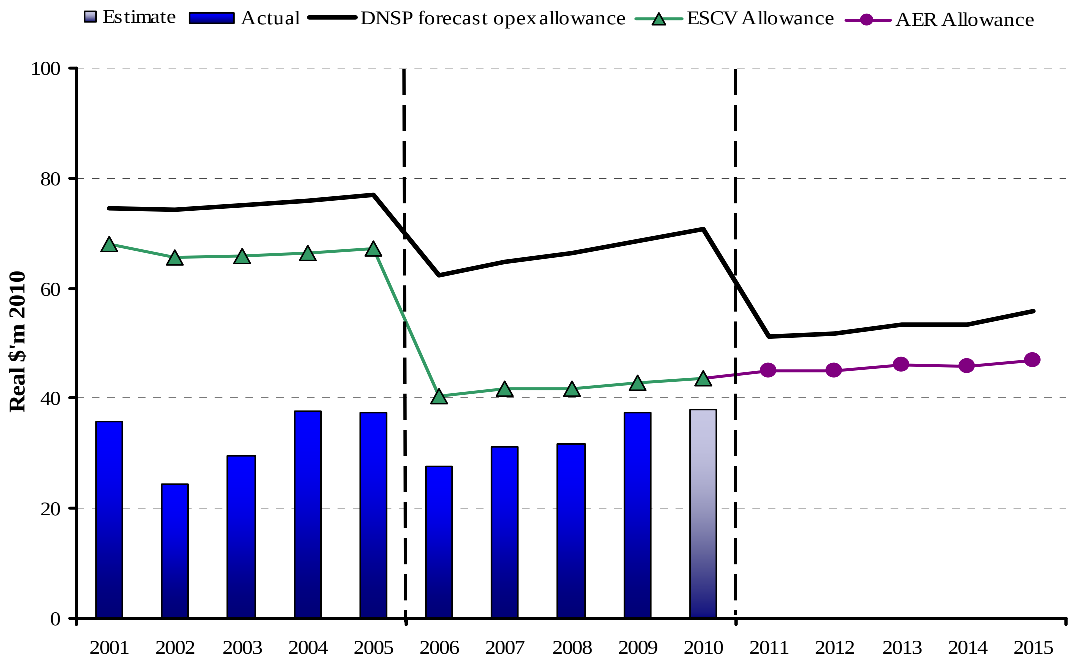
Table 7.31 AER final decision opex allowance for CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower proposed opex	**51.3**	**51.7**	**53.4**	**53.4**	**55.8**	**265.7**
AER opex build-up[a]						
AER base year costs	37.1	37.1	37.1	37.1	37.1	185.7
AER scale escalation	0.3	0.5	0.8	1.0	1.3	3.9
AER real cost escalation	0.3	0.9	1.6	2.6	3.2	8.7
AER step changes[b]	6.5	5.7	5.9	4.1	4.2	26.4
AER debt raising costs	0.7	0.7	0.8	0.8	0.9	3.9
AER self insurance	–	–	–	–	–	–
AER other (GSL)	–	–	–	–	–	0.1
AER total opex	**45.0**	**45.0**	**46.2**	**45.7**	**46.8**	**228.6**
Adjustment	**–6.4**	**–6.7**	**–7.1**	**–7.8**	**–9.0**	**–37.1**
Adjustment (per cent)	**–12.4**	**–13.0**	**–13.4**	**–14.5**	**–16.2**	**–13.9**

Source: AER analysis.
[a]Excludes DMIA allowance. [b]Includes real cost escalation.

Figure 7.6 illustrates the AER's final decision for CitiPower's forecast opex allowance of $228.6 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.6 CitiPower final decision opex comparison



Note: Actual figures are adjusted actuals as used in ECM calculation.

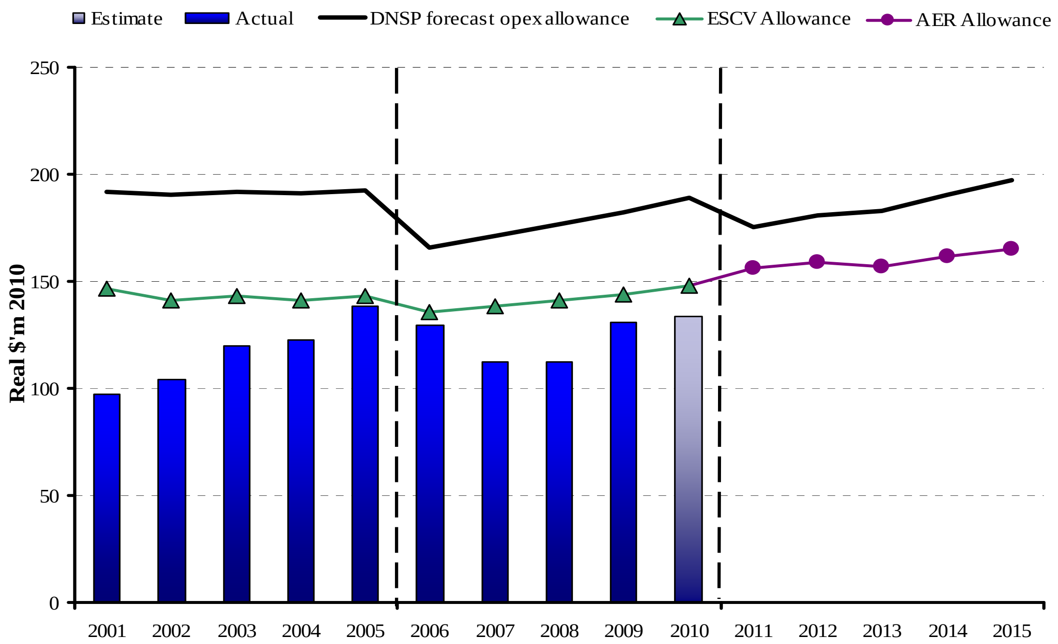
Table 7.32 AER final decision opex allowance for Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Powercor proposed opex	**175.6**	**180.8**	**182.6**	**190.3**	**197.3**	**926.6**
AER opex build–up[a]						
AER base year costs	129.6	129.6	129.6	129.6	129.6	648.1
AER scale escalation	1.2	2.3	3.5	4.7	5.9	17.7
AER real cost escalation	1.2	3.2	5.9	9.5	11.9	31.7
AER step changes[b]	22.0	21.3	15.3	15.0	15.2	88.9
AER debt raising costs	1.2	1.2	1.3	1.4	1.5	6.6
AER self insurance	–	–	–	–	–	–
AER other (GSL)	1.1	1.1	1.1	1.1	1.0	5.5
AER total opex	**156.3**	**158.8**	**156.8**	**161.4**	**165.1**	**798.4**
Adjustment	**–19.3**	**–22.0**	**–25.8**	**–28.9**	**–32.2**	**–128.2**
Adjustment (per cent)	**–11.0**	**–12.2**	**–14.1**	**–15.2**	**–16.3**	**–13.8**

Source: AER analysis.
[a]Excludes DMIA allowance. [b]Includes real cost escalation.

Figure 7.7 illustrates the AER’s final decision for Powercor's forecast opex allowance of $798.4 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.7 Powercor final decision opex comparison



Note: Actual figures are adjusted actuals as used in ECM calculation.

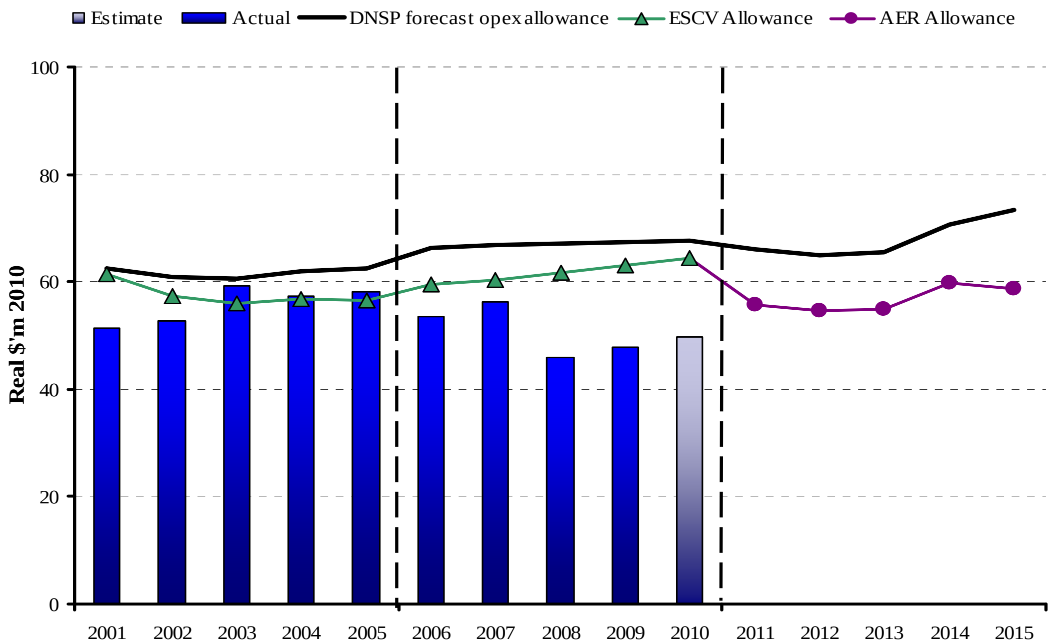
Table 7.33 AER final decision opex allowance for JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN proposed opex	**66.1**	**65.1**	**65.5**	**70.7**	**73.5**	**340.8**
AER opex build–up[a]						
AER base year costs	46.3	46.3	46.3	46.3	46.3	231.7
AER scale escalation	0.3	0.5	0.8	1.0	1.3	3.8
AER real cost escalation	0.5	1.0	1.7	2.6	3.3	9.2
AER step changes[b]	8.2	6.2	5.5	9.2	7.2	36.3
AER debt raising costs	0.4	0.5	0.5	0.5	0.5	2.4
AER self insurance	0.1	0.1	0.1	0.1	0.1	0.5
AER other (GSL)	–	–	–	–	–	0.1
AER total opex	**55.8**	**54.7**	**54.9**	**59.8**	**58.8**	**284.0**
Adjustment	**–10.2**	**–10.4**	**–10.6**	**–10.9**	**–14.7**	**–56.8**
Adjustment (per cent)	**–15.5**	**–15.9**	**–16.1**	**–15.4**	**–20.0**	**–16.7**

Source: AER analysis.
[a]Excludes DMIA allowance. [b]Includes real cost escalation.

Figure 7.8 illustrates the AER's final decision for JEN's forecast opex allowance of $284.0 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.8 JEN final decision opex comparison



Note: Actual figures are adjusted actuals as used in ECM calculation.

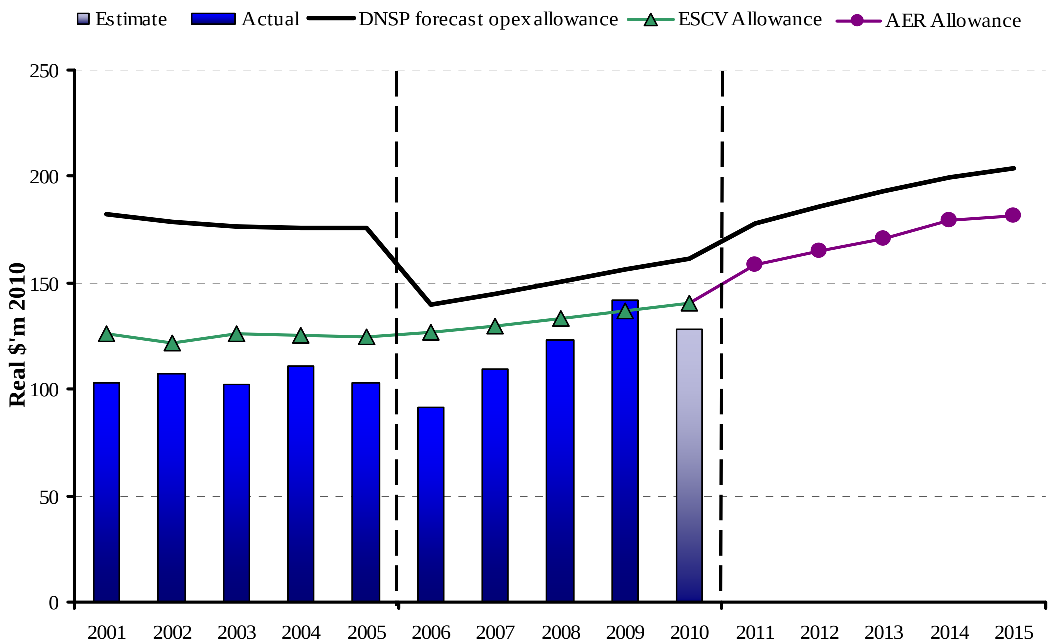
Table 7.34 AER final decision opex allowance for SP AusNet ($'m, 2010)

	2011	2012	2013	2014	2015	Total
SP AusNet proposed opex	**177.9**	**185.6**	**193.0**	**199.3**	**204.2**	**960.1**
AER opex build–up[a]						
AER base year costs	120.1	120.1	120.1	120.1	120.1	600.4
AER scale escalation	0.7	1.4	2.1	2.9	3.6	10.8
AER real cost escalation	0.8	2.5	4.8	7.6	9.2	24.9
AER step changes[b]	30.0	34.3	37.0	42.2	42.3	185.9
AER debt raising costs	1.1	1.2	1.3	1.4	1.5	6.5
AER self insurance	1.3	1.3	1.3	1.3	1.3	6.5
AER other (GSL)	4.2	4.1	4.0	3.9	3.8	20.1
AER total opex	**158.2**	**165.0**	**170.7**	**179.3**	**181.8**	**855.1**
Adjustment	**–19.7**	**–20.6**	**–22.2**	**–20.0**	**–22.4**	**–105.0**
Adjustment (per cent)	**–11.1**	**–11.1**	**–11.5**	**–10.0**	**–11.0**	**–10.9**

Source: AER analysis.
[a]Excludes DMIA allowance. [b]Includes real cost escalation.

Figure 7.9 illustrates the AER's final decision for SP AusNet's forecast opex allowance of $855.1 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.9 SP AusNet final decision opex comparison



Note: Actual figures are adjusted actuals as used in ECM calculation.

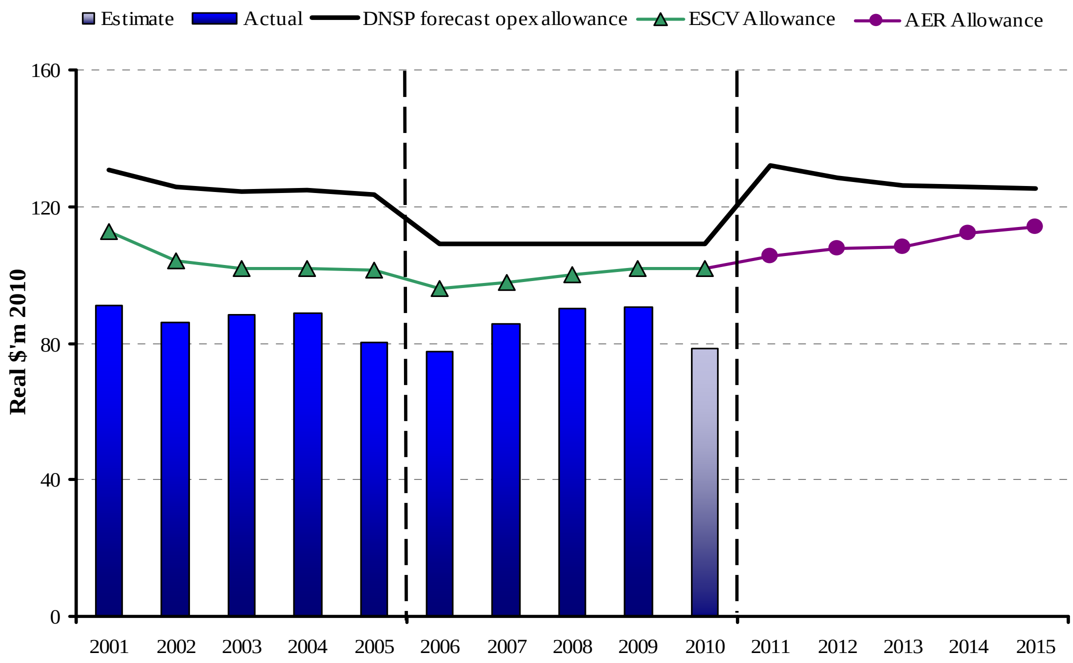
Table 7.35 AER final decision opex allowance for United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
United Energy proposed opex	**131.9**	**128.3**	**126.3**	**125.7**	**125.3**	**637.5**
AER opex build–up[a]						
AER base year costs	92.2	92.2	92.2	92.2	92.2	460.8
AER scale escalation	0.3	0.6	1.0	1.3	1.6	4.8
AER real cost escalation	0.7	2.1	3.8	6.1	7.4	20.2
AER step changes[b]	11.2	11.6	10.1	11.7	11.5	56.1
AER debt raising costs	0.7	0.8	0.8	0.9	0.9	4.2
AER self insurance	–	–	–	–	–	0.1
AER other (GSL)	0.3	0.3	0.3	0.2	0.2	1.3
AER total opex	**105.4**	**107.6**	**108.2**	**112.4**	**113.9**	**547.5**
Adjustment	**–26.5**	**–20.7**	**–18.1**	**–13.3**	**–11.4**	**–90.0**
Adjustment (per cent)	**–20.1**	**–16.2**	**–14.3**	**–10.6**	**–9.1**	**–14.1**

Source: AER analysis.
[a]Excludes DMIA allowance. [b]Includes real cost escalation.

Figure 7.10 illustrates the AER's final decision for United Energy's forecast opex allowance of $574.5 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.10 United Energy final decision opex comparison



Note: Actual figures are adjusted actuals as used in ECM calculation.

8 Forecast capital expenditure

This chapter sets out the AER’s conclusions on forecast capital expenditure (capex) allowances for the Victorian DNSPs for the forthcoming regulatory control period. It also:

- summarises the AER's draft decision capex allowances for the Victorian DNSPs
- provides a general overview of the Victorian DNSPs' revised regulatory proposals
- summarises comments made by stakeholders on the Victorian DNSPs' revised regulatory proposals
- discusses the framework the AER has applied in assessing each proposal against the requirements set out at clause 6.5.7 of the National Electricity Rules (NER)
- sets out the AER's reasons for why it does not accept the Victorian DNSPs' revised capex proposals
- sets out the estimate of the total of each Victorian DNSP's required capex for the forthcoming regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capital expenditure factors (capex factors).

The AER’s conclusions on forecast capex allowances for the forthcoming regulatory control period are set out in section 8.8 of this chapter. Appendix P details further analysis of each category of capex.

8.1 Regulatory requirements

The AER must assess the total of the forecast capex included in each DNSP's building block proposal for the forthcoming regulatory control period. Clause 6.5.7(c) of the NER states that the AER must accept the forecast of required capex of a DNSP that is included in a building block proposal if the AER is satisfied that the total of the forecast capex for the forthcoming regulatory control period reasonably reflects:

> (1) the efficient costs of achieving the capital expenditure objectives; and
>
> (2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the capital expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The capex objectives are contained in clause 6.5.7(a) of the NER. A DNSP is required by clause 6.5.7(a) of the NER to include in its building block proposal the total forecast capex for the regulatory control period that the DNSP considers is required to:

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) maintain the quality, reliability and security of supply of standard control services; and

(4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In deciding whether or not the AER is satisfied that the total capex forecast reasonably reflects the capex criteria, the AER must have regard to the capex factors in clause 6.5.7(e) of the NER. The capex factors the AER must have regard to are:[1]

(1) the information included in or accompanying the building block proposal;

(2) submissions received in the course of consulting on the building block proposal;

(3) any analysis undertaken by or for the AER and published before the distribution determination is made in its final form;

(4) benchmark capex that would be incurred by an efficient DNSP over the regulatory control period;

(5) the actual and expected capex of the DNSP during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between opex and capex;

(8) whether the total labour costs included in the capex and opex forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent to which the forecast of required capex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) the extent the DNSP has considered, and made provision for, efficient non-network alternatives.

If the AER is not satisfied that the total capex forecast reasonably reflects the capex criteria, the AER must not accept the capex forecast.[2] If the AER does not accept a forecast capex proposal in accordance with clause 6.5.7(d), clause 6.12.1(3)(ii) of the NER states that:

> The AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required capital expenditure for the regulatory control period that the AER is satisfied

1 NER, clause 6.5.7(e).
2 NER, clause. 6.5.7(d).

reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors.

Under clause 6.12.3(f)(2) of the NER, this estimate must be the minimum adjustment to the proposed forecast capex necessary to comply with the NER.

8.2 AER draft decision

The AER's draft decision conclusion on capex allowances for the Victorian DNSPs was set out chapter 8 of the draft decision and is summarised in table 8.1 below.

Table 8.1 AER draft decision capex allowance for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
Reinforcement	172.9	192.9	65.4	226.9	132.9	791.1
Gross demand connections	262.6	627.2	132.8	430.6	221.8	1675.1
Reliability and quality maintained	183.0	320.9	73.6	301.3	143.0	1021.9
Environment, safety and legal obligations	8.4	42.1	26.9	14.1	43.1	134.5
SCADA & network control	7.0	15.7	3.3	0.0	0.0	26.0
Non-network general - IT	24.9	61.0	51.3	74.3	98.5	310.0
Non-network general - other	17.0	40.4	18.1	18.3	13.2	107.1
Total gross capex	**675.8**	**1300.2**	**371.5**	**1065.6**	**652.4**	**4065.5**
Less customer contributions	108.5	291.0	56.9	112.2	120.9	689.4
Total net capex	**567.4**	**1009.2**	**314.6**	**953.3**	**531.5**	**3376.1**

Source: AER, *Draft decision - Victorian electricity distribution network service providers distribution determination 2011–2015,pp. 434-438.*
Capex in this table include the AER's draft decision on margins, overheads and real cost increases.

8.3 Victorian DNSP revised regulatory proposals

Table 8.2 Victorian DNSP revised capex proposals for 2011–15 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy	Total
Reinforcement	322.5	313.7	128.1	450.6	214.1	1429.0
Gross demand connections	315.2	732.5	160.0	453.5	251.7	1913.0
Reliability and quality maintained	266.4	481.8	159.1	493.4	280.3	1681.0
Environment, safety and legal obligations	7.4	42.1	36.0	6.5	70.1	162.1
SCADA & network control	23.8	37.7	3.1	7.9	1.5	74.0
Non-network general - IT	53.0	129.9	72.0	150.4	110.9	516.2
Non-network general - other	16.3	87.9	62.3	19.2	20.9	206.5
Total gross capex	**1004.6**	**1825.5**	**620.7**	**1581.5**	**949.4**	**5981.7**
Less customer contributions	55.4	219.2	38.8	47.7	134.0	495.1
Total net capex	**949.1**	**1606.3**	**581.9**	**1533.8**	**815.4**	**5486.6**

Source: CitiPower, *Revised Regulatory Proposal*, RIN template 2.1, Powercor, *Revised Regulatory Proposal*, RIN template 2.1, JEN, *Revised Regulatory Proposal*, RIN template 2.1, SP AusNet, *Revised Regulatory Proposal*, RIN template 2.1, United Energy, *Revised Regulatory Proposal*, RIN template 2.1.
Capex in this table include the AER's draft decision on margins, overheads and real cost increases.

CitiPower

CitiPower's revised regulatory proposal did not accept the AER's draft decision for forecast capex in the forthcoming regulatory control period. Its key concerns regarding the AER's draft decision were:

- perceived inconsistency of approach with previous AER distribution determinations and decision making processes
- perceived 'evidentiary threshold' (request for cost benefit analysis) requirements by the AER that ignore the difficulties that confront a regulated business in a price review process
- the AER's failure to use 2009 actual data to model historical capex
- the AER's use of a 'revealed cost' approach to estimating its substitute forecast capex in the forthcoming regulatory control period

- the practical and relevant experience of the AER's consultant, Nuttall Consulting.[3]

In its revised regulatory proposal, CitiPower accepted the AER's draft decision on:

- new customer connections, subject to resolution of issues regarding classification of connection services
- environmental, safety and legal capex
- non-network other capex

but sought to restate the amounts as per its initial regulatory proposal in the following areas which the AER did not accept in its draft decision:

- reinforcement capex
- reliability and quality maintained capex
- SCADA and network control capex
- non-network IT capex.[4]

CitiPower's revised regulatory proposal on forecast capex in the forthcoming regulatory control period is set out in table 8.3 and the AER's considerations are set out in appendix P.

Table 8.3 CitiPower revised capex proposal for 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	60.7	66.6	81.7	66.2	47.4	322.5
Gross demand connections	60.0	62.3	62.6	64.2	66.2	315.2
Reliability and quality maintained	46.1	50.8	52.0	56.7	60.8	266.4
Environment, safety and legal obligations	1.4	1.5	1.5	1.5	1.5	7.4
SCADA & network control	4.8	4.5	4.7	4.8	4.9	23.8
Non-network general - IT	9.9	9.0	8.9	14.0	11.1	53.0
Non-network general - other	3.1	3.4	3.2	3.3	3.3	16.3
Total gross capex	**186.1**	**198.0**	**214.6**	**210.6**	**195.2**	**1004.6**
Less customer contributions	9.6	10.9	11.0	11.7	12.3	55.4
Total net capex	**176.5**	**187.2**	**203.6**	**199.0**	**182.8**	**949.1**

Source: CitiPower, *Revised Regulatory Proposal*, RIN template 2.1.

3 CitiPower, *Revised regulatory proposal*, October 2010, p. 247.
4 ibid., pp 247–249.

Capex in this table include the AER's draft decision on margins, overheads and real cost increases.

Powercor

Powercor's revised regulatory proposal did not accept the AER's draft decision for forecast capex in the forthcoming regulatory control period. Its key concerns regarding the AER's draft decision were:

- perceived inconsistency of approach with previous AER distribution determinations and decision making processes
- perceived 'evidentiary threshold' (request for cost benefit analysis) requirements by the AER that ignore the difficulties that confront a regulated business in a price review process
- the AER's failure to use 2009 actual data to model historical capex
- the AER's use of a 'revealed cost' approach to estimating its substitute forecast capex in the forthcoming regulatory control period
- the practical and relevant experience of the AER's consultant, Nuttall Consulting.[5]

In its revised regulatory proposal, Powercor accepted the AER's draft decision on:

- new customer connections, subject to resolution of issues regarding classification of connection services
- environmental, safety and legal capex
- non-network other capex

but sought to restate the amounts as per its initial regulatory proposal in the following areas which the AER did not accept in its draft decision:

- reinforcement capex
- reliability and quality maintained capex
- SCADA and network control capex
- non-network IT capex.[6]

Powercor's revised regulatory proposal on forecast capex in the forthcoming regulatory control period is set out in table 8.4 and the AER's considerations are set out in appendix P.

5 Powercor, *Revised regulatory proposal*, October 2010, p. 237.
6 ibid., pp. 237–239.

Table 8.4 Powercor revised capex proposal for 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	55.8	57.8	63.7	65.2	71.2	313.7
Gross demand connections	141.3	144.5	147.1	149.0	150.7	732.5
Reliability and quality maintained	91.1	100.4	99.9	94.8	95.8	481.8
Environment, safety and legal obligations	8.2	8.4	8.5	8.5	8.6	42.1
SCADA & network control	7.0	7.6	7.8	7.7	7.7	37.7
Non-network general - IT	26.5	23.1	21.0	32.9	26.3	129.9
Non-network general - other	17.1	18.3	17.4	17.5	17.5	87.9
Total gross capex	**346.9**	**360.0**	**365.4**	**375.6**	**377.7**	**1825.5**
Less customer contributions	42.2	43.2	44.1	44.6	45.1	219.2
Total net capex	**304.8**	**316.7**	**321.3**	**331.0**	**332.6**	**1606.3**

Source: Powercor, *Revised Regulatory Proposal*, RIN template 2.1.
Capex in this table include the AER's draft decision on margins, overheads and real cost increases.

JEN

JEN's revised regulatory proposal did not accept the AER's draft decision for forecast capex in the forthcoming regulatory control period. It noted that it is facing difficult challenges posed by a reduction in surplus network capacity and increases in peak demand as increasing volumes of its network assets approach the end of their lives. Therefore, JEN considered it must escalate the replacement of its assets before performance deteriorates, safety is compromised and costs escalate.[7]

JEN submitted that its revised regulatory proposal to the AER was supported by detailed costing and analysis of projects to address the AER's and Nuttall Consulting's concerns on scope and cost optimisation, and would allow it to comply with statutory and regulatory obligations and meet the challenges posed by declining asset conditions.[8]

In its revised regulatory proposal, JEN accepted the AER's draft decision on:

- new customer connections
- SCADA and network control capex

but sought to restate the amounts as per its initial regulatory proposal in the following areas which the AER did not accept in its draft decision:

7 JEN, *Revised regulatory proposal*, October 2010, pp. 135–136.
8 ibid., p. 135.

- reinforcement capex
- reliability and quality maintained capex
- environmental, safety and legal capex
- non-network IT capex
- non-network other capex.[9]

JEN's revised regulatory proposal on forecast capex in the forthcoming regulatory control period is set out in table 8.5 and the AER's considerations are set out in appendix P.

Table 8.5 JEN revised capex proposal for 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	20.6	26.0	26.6	28.1	26.8	128.1
Gross demand connections	26.6	26.7	32.6	35.1	39.1	160.0
Reliability and quality maintained	26.6	26.0	29.5	35.2	41.8	159.1
Environment, safety and legal obligations	7.4	9.8	7.2	5.9	5.7	36.0
SCADA & network control	0.7	0.9	1.2	0.3	0.0	3.1
Non-network general - IT	20.3	21.0	17.2	6.6	6.8	72.0
Non-network general - other	19.5	24.3	7.7	4.6	6.3	62.3
Total gross capex	**121.6**	**134.7**	**122.0**	**115.8**	**126.5**	**620.7**
Less customer contributions	7.2	7.2	8.1	7.9	8.5	38.8
Total net capex	**114.5**	**127.5**	**113.9**	**108.0**	**118.0**	**581.9**

Source: JEN, *Revised Regulatory Proposal*, RIN template 2.1.
Capex in this table include the AER's draft decision on margins, overheads and real cost increases.

SP AusNet

SP AusNet's revised regulatory proposal did not accept the AER's draft decision for forecast capex in the forthcoming regulatory control period. Its key concern regarding the AER's draft decision was the perceived inconsistency of approach with AER distribution determinations in other State and Territory jurisdictions, including:

- placing a heavier reliance on historical actual capex to determine forecast capex
- rejection of bottom-up planning to determine aggregate reinforcement capex

9 ibid., pp. 140–174.

- an emphasis on age-based asset replacement, rather than condition-based.[10]

SP AusNet was also concerned that the AER's draft decision drew conclusions for the Victorian DNSPs as a whole, for example, in discussing capex forecasting accuracy without differentiating SP AusNet.[11]

In its revised regulatory proposal, SP AusNet accepted the AER's draft decision on:

- new customer connections
- environmental, safety and legal capex
- non-network other capex, subject to application of a scale escalator

but sought to restate the amounts as per its initial regulatory proposal in the following areas which the AER did not accept in its draft decision:

- reinforcement capex
- reliability and quality maintained capex
- SCADA and network control capex
- non-network IT capex.[12]

SP AusNet's revised regulatory proposal on forecast capex in the forthcoming regulatory control period is set out in table 8.6 and the AER's considerations are set out in appendix P.

[10] SP AusNet, Revised regulatory proposal, pp. 75–84.
[11] ibid., pp. 84.
[12] ibid., pp. 93–158.

Table 8.6 SP AusNet revised capex proposal for 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	79.8	88.1	110.6	74.3	97.8	450.6
Gross demand connections	95.0	93.8	89.8	85.9	89.1	453.5
Reliability and quality maintained	85.2	102.8	93.0	95.6	116.8	493.4
Environment, safety and legal obligations	1.3	1.3	1.3	1.3	1.3	6.5
SCADA & network control	0.6	0.8	1.2	4.3	1.0	7.9
Non-network general - IT	32.8	38.6	28.6	32.4	18.1	150.4
Non-network general - other	3.7	3.8	3.8	3.9	4.0	19.2
Total gross capex	**298.3**	**329.1**	**328.2**	**297.8**	**328.1**	**1581.5**
Less customer contributions	10.2	10.0	9.4	8.9	9.2	47.7
Total net capex	**288.1**	**319.1**	**318.8**	**288.9**	**318.9**	**1533.8**

Source: SP AusNet, *Revised Regulatory Proposal*, RIN template 2.1.
Capex in this table include the AER's draft decision on margins, overheads and real cost increases.

United Energy

United Energy's revised regulatory proposal did not accept the AER's draft decision for forecast capex in the forthcoming regulatory control period. Its key comments regarding the AER's draft decision were:

- historical capex is a poor guide to future capex requirements
- a bottom-up approach to determining reliability and quality maintained capex is consistent with good industry practice
- the probabilities used in assessing the timing of reinforcement projects appear to be subjective and biased.[13]

United Energy considered that a reduced capex allowance would constrain its expenditure and adversely affect network reliability and compliance. In its revised regulatory proposal, United Energy accepted the AER's draft decision on:

- new customer connections
- non-network other capex, subject to inclusion of expenditures omitted by United Energy at the time of its initial regulatory proposal to the AER

but sought to restate the amounts as per its initial regulatory proposal in the following areas which the AER did not accept in its draft decision:

[13] United Energy, *Revised regulatory proposal*, October 2010, p. 103.

- reinforcement capex
- reliability and quality maintained capex
- environmental, safety and legal capex
- SCADA and network control capex
- non-network IT capex.[14]

United Energy's revised regulatory proposal on forecast capex in the forthcoming regulatory control period is set out in table 8.7 and the AER's considerations are set out in appendix P.

Table 8.7 United Energy revised capex proposal for 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	45.0	48.2	49.5	40.9	30.4	214.1
Gross demand connections	53.4	51.9	50.1	49.0	47.3	251.7
Reliability and quality maintained	61.8	58.9	57.1	50.8	51.8	280.3
Environment, safety and legal obligations	22.4	15.5	13.1	9.8	9.3	70.1
SCADA & network control	0.0	0.7	0.7	0.0	0.0	1.5
Non-network general - IT	23.5	36.5	27.6	16.0	7.2	110.9
Non-network general - other	8.8	4.3	2.5	2.8	2.5	20.9
Total gross capex	**214.9**	**215.9**	**200.7**	**169.4**	**148.5**	**949.4**
Less customer contributions	27.7	27.1	26.5	26.8	26.0	134.0
Total net capex	**187.2**	**188.8**	**174.2**	**142.6**	**122.5**	**815.4**

Source: United Energy, *Revised Regulatory Proposal*, RIN template 2.1.
Capex in this table include the AER's draft decision on margins, overheads and real cost increases.

8.4 Submissions

The AER received submissions in relation to capex from a range of end user representatives, energy retailers and government in response to its draft decision and the Victorian DNSPs' revised regulatory proposals. The following capex issues were raised by stakeholders:

- CitiPower and Powercor noted the Victorian Bushfires Royal Commission's (VBRC) Final Report supported specific pass through events for bushfires and new obligations under the *Electricity Safety Act 1998*. In addition, CitiPower and

14 ibid., pp. 119–153.

Powercor commented on the unreasonableness of the AER's repex model in forecasting replacement capex.[15]

- JEN requested for a specific bushfire pass through event and provided an update on its revised costs with regard to the new electricity safety regulations.[16]

- The Energy Users Association of Australia (EUAA) agreed with the AER's revealed cost approach to assessing capex and noted that the AER failed to apply benchmarking to its capex assessment.[17]

- The Consumer Action Law Centre (CALC) recommended that the AER not approve the increases in capex proposed by the Victorian DNSPs, and instead adopt the AER's capex allowance in its draft decision. CALC supported establishing a specific bushfire pass through event if the Victorian Government decision was not announced prior to the release of the AER's final decision. CALC also detailed a proposal for the AER to utilise its information gathering powers further to understand the detail of the Victorian DNSPs' Asset Management Plans.[18]

- Consumer Utilities Advocacy Centre (CUAC) was supportive of the AER’s approach to examining historical capex as a basis for assessing future capex levels in the draft decision. CUAC considered that an examination of trend levels of network expenditure suggests a fairly predictable trend. This is in contrast with the approach adopted in the Victorian DNSPs' revised regulatory proposals, which advocate significant upfront capex. Further, CUAC was of the view that any ageing network assets should be replaced progressively over time to ensure the minimisation of one-off price impacts to consumers.[19]

- Origin did not support the request for specific pass through events to address the recommendations arising from the VBRC and changes in safety regulations by Energy Safe Victoria (ESV). Origin supported setting specific percentage limits in the materiality threshold (defined as a percentage of revenue) for nominated pass through events to ensure pass through events can only be approved if they have a material impact on the DNSP. Origin noted there would be considerable benefit in on-going monitoring of actual capex levels and outcomes achieved by the Victorian DNSPs against the approved allowances in the AER's distribution determinations.[20]

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15 CitiPower, Powercor, Submission to the AER - *Victorian Bushfire Royal Commission – Implications of the Final Report for the EDPR*, 19 August 2010, pp. 1-3.

16 JEN, Submission to the AER - *JEN 2011–15 regulatory proposal: Further response to the draft determination*, 19 August 2010, pp. 1-3.

17 Energy Users Association of Australia (EUAA), Submission to the AER - *AER Draft Determination on Victorian electricity distribution prices for the period 2011–2015 and distributors revised proposals*, 19 August 2010, pp. i-ii.

18 Consumer Action Law Centre, *Submission to the AER's Victorian Draft Distribution Determination 2011– 2015*, 19 August 2010, pp. 3-5, 12-19

19 Consumer Utilities Advocacy Centre (CUAC), Submission in response to the AER draft electricity distribution determination for Victoria and the distribution businesses revised revenue proposals,19 August 2010, p.2

20 Origin, Submission to the AER – *Victorian Electricity Distribution Draft Determination and Revised Proposals*, 19 August 2010, pp. 5-6.

- The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria, disagreed with the AER's interpretation of the NER with respect to roll-forward of capex incurred during 2006–10 into the regulatory asset base (RAB).[21]

- Grid Australia stated that the AER disproportionately relied on a revealed cost approach to establish its capex allowances. Grid Australia was concerned about the potential for regulatory inconsistency and uncertainty across jurisdictions because the AER's approach to the capex analysis in Victoria appeared to be inconsistent with other jurisdictions.[22]

- EnergyAustralia submitted that the AER did not have proper regard to the assessment framework prescribed under the NER and had rejected capex that satisfied the capex criteria and the revenue and pricing principles. EnergyAustralia also stated that the AER had developed new models and high level tests, including its repex model, that do not provide a reliable or robust method for determining forecast capex requirements. Further, EnergyAustralia submitted that the AER should improve the transparency and predictability of its decision making. In particular EnergyAustralia asserted that the AER had developed new approaches and tests without consulting its stakeholders and relied on analysis that had not been published as part of its draft decision. EnergyAustralia expressed concerned that the AER had substituted the Victorian DNSPs' inputs without clearly demonstrating why those inputs were unreasonable or why its own substituted inputs were superior.[23]

- The Energy Users Coalition of Victoria (EUCV) contended that the Victorian DNSPs' capex demands were inflated and stated that the AER had a 'generous view of escalators.' The EUCV supported the AER's repex model and proposal to address the VBRC outcomes as a separate pass through event.[24]

- TRUenergy supported the AER's use of the revealed cost approach in establishing an efficient capex allowance for the 2011–15 regulatory control period.[25]

8.5 Consultant review

In its draft decision, the AER engaged Nuttall Consulting to review areas of significant capex increases. Nuttall Consulting continued to assist the AER in its assessment of capex in the final decision. As set out in section 8.6.2, since the draft decision was published, major changes to the safety management framework for the Victorian DNSPs have taken effect. In the review of safety-driven capex, Energy Safe Victoria (ESV) has recommended volumes for each of the items that it considers prudent for the Victorian DNSPs to undertake in the forthcoming regulatory control

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[21] Minister for Energy and Resources, *Submission on the Victorian Electricity Distribution Network Service Providers' regulatory proposals for 2011–2015*, 20 August 2010, pp. 1-5.

[22] Grid Australia, *Submission to the AER – Victorian Electricity Distribution Draft Decision 2011–2015, 19 August 2010*, pp. 1-2, 4-5.

[23] Energy Australia, *Energy Australia submission on AER draft regulatory determination for Victorian distributors*, 19 August 2010, pp. 1-8.

[24] Energy Users Coalition of Victoria (EUCV), *Submission to the AER - 2010 AER review of Victorian Electricity DBs, EUCV response to AER Draft Decision,* August 2010, pp. 15-25

[25] TRUenergy, *Submission to the AER - Victorian electricity distribution network service providers distribution determination 2011–2015: Draft decision*, 16 August 2010, p.2

period. The AER requested Nuttall Consulting to only undertake a review of the efficient unit costs for these specific items.

As part of its review of the Victorian DNSPs' initial regulatory proposals, Nuttall Consulting also reviewed the Victorian DNSPs' proposals for the regulatory periods from 2001–10, as well as the previous allowances set by the previous regulator, the Essential Services Commission of Victoria (ESCV). Additionally, Nuttall Consulting reviewed the relative capital efficiencies of the Victorian DNSPs, particularly with respect to other National Electricity Market (NEM) States.

Since the draft decision, new data have become available and have been used in Nuttall Consulting's review. Nuttall Consulting have taken the Victorian DNSPs' audited 2009 data, and the revised estimates of capex for 2010-15, from the Victorian DNSPs' revised regulatory proposals into account in their analysis.[26]

In Nuttall Consulting's comparison of the level of capex efficiencies across the NEM, Nuttall Consulting plotted capex per customer against customer density for each of the NEM DNSPs. This plot demonstrated that the Victorian DNSPs generally sit below the regression line.[27] Nuttall Consulting also compared a plot of the ratio of capex to the regulated asset base. From this analysis, Nuttall Consulting concluded that the existing level of actual capex was relatively efficient for the Victorian DNSPs.[28] Nuttall Consulting's analysis also found that the historical accuracy of the Victorian DNSPs' forecast capex proposals was relatively poor.[29]

The analysis of the Victorian DNSPs' historical capex, including an assessment of their relative capex efficiency and a review of the accuracy of their previous capex forecasts, has provided Nuttall Consulting with insight into the Victorian DNSPs' capacity to anticipate future capex. It has also allowed Nuttall Consulting to assess the rigour of the Victorian DNSPs' proposed forecast capex allowances against actual capex incurred during the regulatory control period. Nuttall Consulting's review process has identified areas of where forecasts require further review.

In summary, Nuttall Consulting's review process involved:

- detailed desktop reviews of each Victorian DNSP’s capex proposals and supporting information
- examining whether each Victorian DNSP had considered, and made provision for, efficient non-network alternatives
- considering the relative prices of operating and capital inputs and the substitution possibilities between opex and capex
- considering governance frameworks to ensure capex proposals are line with capex policies and procedures and are consistent with the capex objectives

[26] Nuttall Consulting, Report – *Capital Expenditure, Victorian Electricity Distribution Revenue Review, Revised Proposals*, October 2010, p.17.
[27] ibid., pp. 19.
[28] ibid., p. 17–18.
[29] ibid., p. 21.

- requesting additional information from the Victorian DNSPs to aid Nuttall Consulting's understanding and considerations of the Victorian DNSPs' capex programs and development of views on key issues
- consulting with the AER on the areas of the capex review.[30]

Nuttall Consulting found that:

- overall level of capex in Victoria as revealed in the previous five years appears relatively efficient
- compared to their interstate counterparts, the Victorian DNSPs appear reasonably efficient
- Victorian DNSPs have consistently forecast higher levels of capex than has actually been required, although there is a significant level of variability in the level of forecast accuracy
- the apparent overall bias towards over-forecasting may be in some part due to the Victorian DNSPs achieving efficiencies in capex. However, these potential efficiencies do not appear to sufficiently explain the variations between forecast and actual capex
- Victorian DNSPs have generally estimated higher levels of capex for the remaining years of a regulatory control period than the capex that has actually been required.
- capex forecasts for the 2011–15 regulatory control period are significantly above the actual capex trend line. Capex categories that represent the greatest contribution to these increases are reinforcement, new customer connection and load movement, reliability and quality maintained, and non-network general IT.[31]

The Victorian DNSPs criticised Nuttall Consulting's review in their revised regulatory proposals, questioning whether all relevant factors had been considered and whether the repex model was fit for its purpose.[32] The Victorian DNSPs also contended that the revealed historical capex was not indicative of future capex requirements.[33] In its report, Nuttall Consulting has responded to these criticisms, noting that many of the criticisms misrepresented the use of analysis tools such as the repex model, and the process undertaken by Nuttall Consulting.[34] These issues are detailed further in appendix P.

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30 Nuttall Consulting, Report – *Capital Expenditure, Victorian Electricity Distribution Revenue Review, Revised Proposals*, October 2010, pp. 10-11.

31 Nuttall Consulting, Report – *Capital Expenditure, Victorian Electricity Distribution Revenue Review, Revised Proposals*, October 2010, 10-12; Nuttall Consulting, Victorian Electricity Distribution Revenue Review, May 2010.

32 Refer to Appendix P for further details.

33 Refer to Appendix P for further details.

34 Nuttall Consulting, Report – *Capital Expenditure, Victorian Electricity Distribution Revenue Review, Revised Proposals*, October 2010, pp. 12-13.

8.6 Issues and AER considerations

8.6.1 AER approach to assessment

8.6.1.1 Capital expenditure criteria and factors

In deciding whether the Victorian DNSPs' forecast capex reasonably reflects the capex criteria, as required by the NER, the AER has taken into account the capex factors. Section 8.1 of this chapter sets out the capex criteria and factors the AER had regard to in its assessment of forecast capex for the Victorian DNSPs in the forthcoming regulatory control period. Appendix P sets out the AER's considerations of the capex criteria and factors in its assessment of each capex category in more detail.

8.6.1.2 Capital expenditure assessment framework

In deciding whether a forecast capex allowance reasonably reflects the capex criteria, the AER has:

- considered the revised regulatory proposals provided by the Victorian DNSPs, taking into account submissions received
- done so in a manner that will or is likely to contribute to the national electricity objective (NEO) in which is set out at section 7 of the NEL.
- taken into account the revenue and pricing principles set out in section 7A of the NEL.
- taken into account the capex factors, criteria and objectives set out in clause 6.5.7 of the NER.

The Victorian DNSPs' revised regulatory proposals and submissions received in response to the draft decision raised some issues in relation to the AER's approach to assessing capex.[35] For this reason, the AER considers it pertinent, as part of this final decision, to outline its approach to assessing the Victorian DNSPs' proposed forecast capex under clause 6.5.7 of the NER. The following section sets out the AER’s approach in greater detail so that the assessment of the capex factors can be better understood along with the role of the analytical methods and tools used in the AER’s analysis.

The AER’s decision requires it to be satisfied that the *total* forecast capex reasonably reflects the capex criteria, not each individual program and project which constitutes that total. The capex criteria set out at in clause 6.5.7(c) of the NER state:

> The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects:
>
> (1) the efficient costs of achieving the capital expenditure objectives; and

35 Grid Australia, *Submission to the AER, 19 August 2010*, pp. 1-2, 4-5; EnergyAustralia, *Submission to the AER*, 19 August 2010, pp. 1-8.

> (2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the capital expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Read together, the AER considers the three capex criteria are complementary and are designed to identify the level of efficient costs a prudent operator in the circumstances of each DNSP, would be required to incur, based on a realistic expectation of the demand forecast and the cost inputs required to achieve the capex objectives. The AER considers that the level of efficient costs referred to here are those expected costs that would be based on the outcomes in a workably competitive market.

Contrary to the AER's view above, some submissions have posited that there is an internal tension between the capex criteria and that the reference to 'efficient costs' in clause 6.5.7(c)(1) competes with and is not complementary to the reference to 'prudent operator' in clause 6.5.7(c)(2).[36] The corollary of these submissions is that a prudent operator, who balances risk, would incur a premium above what is otherwise the efficient level of costs.

The AER does not consider that this is an appropriate interpretation of the capex criteria, having regard to the regulatory framework for distribution services under Chapter 6 of the NER, and the NEO. This is because the capex criteria operate together to control or limit the amount of forecast expenditure that a DNSP would face if exposed to a competitive market. In particular, the AER considers that a DNSP's forecast capex must be based only on the costs that:

- would be incurred in a workably competitive market so that the costs reflect the efficient costs of achieving the capex objectives (clause 6.5.7(c)(1))
- these costs must only include activities or actions by the DNSP that would be incurred by a prudent operator in the circumstances of the DNSP to achieve the capex objectives (clause 6.5.7(c)(2)) and
- reflect a realistic expectation of the demand forecast and costs inputs required to achieve the capex objectives (clause 6.5.7(c)(3).

The AER considers that this interpretation promotes the long term interests of customers consistent with the NEO where the DNSP will only pass on to customers those costs which are efficient and are necessary or reflect good industry practice, for the DNSPs to provide standard control services.

The NEO is contained in section 7 of the NEL:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability and security of supply of electricity; and

[36] CitiPower, *Revised regulatory proposal*, p. 511; Powercor, *Revised regulatory proposal*, p. 517.

(b) the reliability, safety and security of the national electricity system.

Characterising the capex criteria as complementary requires the AER to identify the level of efficient costs, and by identifying that level of efficient costs, the AER is promoting efficient investment in, and efficient operation of the use of electricity services for the long term interests of consumers with respect to the price of electricity. The AER considers that this interpretation of clause 6.5.7 promotes the achievement of the NEO.

Where costs are efficient, it necessarily follows that prices for services are also efficient. Therefore, in providing the DNSPs with a total forecast capex allowance that reasonably reflects the efficient costs of maintaining the quality, safety and reliability of supply of the network, the AER is meeting both limbs of the NEO.

In deciding whether the DNSP's forecast capex allowance reasonably reflects the capex criteria, as required by the NER, the AER has taken into account the capex factors. It is also important to recognise that clause 6.5.7 of the NER does not require all the capex factors be taken into account in reviewing every program or project that may constitute a forecast capex allowance. Rather, in practice, the AER has only done so to the extent it is relevant and has considered it appropriate to do so. It should be noted that the process of considering weighing the relative importance of the capex factors in relation to a specific item of expenditure is not carried out in a formulaic manner. The relative importance of each factor necessarily involve the exercise of judgement based on the specific material being reviewed and accordingly, the each factor's relative importance can, and does, vary for each item of capex reviewed. For many items, some of the capex factors will not be relevant or, by virtue of the AER considering the underlying costs of particular services, instead of fully absorbed costs, some issues will be dealt with at a different point in the analysis.

In taking these capex factors into account in the context of the capex criteria, the AER has also employed a number of analytical methodologies and tools, and the assistance of consultants, as appropriate.

In past decisions the AER has relied on its consultants to review the forecasts prepared by the regulated entity and prepare advice which is weighed against the regulated entity's forecasts. This approach has continued in this decision. Progressively, the AER has also been undertaking some elements of the analysis internally and developed tools, methodologies and approaches to achieve this end. A notable example is the development of a methodology to forecast future material costs which has emerged since 2008 and has since been employed in both the transmission and distribution decisions in Queensland, South Australian and New South Wales and the transmission decision in Tasmania, as well as this decision.

Most recently the AER has developed the repex model to assist its assessment of replacement expenditure forecasts. The use of the repex model as a benchmarking analysis tool is further discussed in section 8.6.1.3 and in appendix P to this decision. Historical costs have been examined in past regulatory decisions but in recent years the tendency has been for regulated entities to have been close to or to have overspent regulatory allowances. The observed trend of the Victorian businesses was quite different in this regard. This is also discussed further in section 8.6.1.3.

Where the AER is not satisfied that the proposed forecast capex reasonably reflects the capex criteria, the AER can not accept the forecast. It must then substitute its own forecast, modified only to the extent necessary to make the proposed forecast capex compliant with clause 6.12.3(f) of the NER. In proposing a capex forecast as a total, each Victorian DNSP proposed an allowance for various components of their total proposed capex forecast. The assessment of these components is relevant to determining whether the AER is satisfied that the *total* proposed forecast capex or its estimate of the required capex reasonably reflects the capex criteria. For replacement expenditure the volume predicted by the repex model are an estimate of the total number of assets of a particular age profile that are likely to require replacement. The AER has sought to broadly align the output of the model with the historical experience of asset replacements. The AER has not identified any reasons why a lesser volume would be appropriate for any asset category. The AER therefore considers that for the purposes of this decision, the volumes predicted by the repex model represent a minimum or floor value for asset replacement activity which would be consistent with good industry practice by a prudent and efficient operator.

Substantial comment has been made in the Victorian DNSPs' revised regulatory proposals regarding the AER's approach to the calibration of the repex model, choice of asset lives and inputs and outputs derived from the model.[37] These issues are discussed in detail in appendix P. In summary, the AER considers that its assessment of the *total* efficient capex forecast is consistent with the NER and NEL. The following section sets out how the AER assessed the *total* forecast capex.

Assessing the total forecast capital expenditure

The starting point for assessing whether the total forecast capex reasonably reflects the capex criteria is to consider the information provided by each of the Victorian DNSPs in their regulatory proposal and accompanying information. To facilitate the analysis of smaller value matters, the AER and its consultants categorised capex items with similar characteristics together where practical and where individual items were considered not to merit detailed investigation. The categories are:

- new customer connections
- reinforcement
- reliability and quality maintained
- environment, safety and legal
- SCADA and network control
- non-network IT and network other.

Broadly, the assessment of the total forecast capex involved the examination of:

- the methods and assumptions the Victorian DNSPs used to develop their revised capex proposal

[37] Refer to appendix P for further details.

- the estimates of real cost escalators
- the individual projects and programs that form the forecast capex
- the scope and timing of the forecast capex
- the deliverability of the forecast capex
- both the existence and the timely application of the governance policies and procedures of the DNSP both to the works and services it undertakes and to the preparation of proposals for future capex.

This review has adopted the findings of the draft decision as a starting point for this investigation. The AER considers that the Victorian DNSPs proposed forecasts of capex should be developed with a similar degree of rigour as the DNSP applies to the subsequent implementation of capex. In conducting its review, the AER was cognisant that the actual policies and procedures employed by the Victorian DNSPs for preparing forecasts would not be identical to those governing later investment decisions.

The AER's draft decision identified a number of gaps in the Victorian DNSPs' information supporting particular forecasts of future capex. In the final decision, the AER has reviewed the revised regulatory proposals to examine whether Victorian DNSPs have adequately addressed the concerns raised by the AER in the draft decision. To the extent a DNSP's revised documentation has provided a detailed business case for a forecast, the AER has been better able to assess whether it is satisfied that the forecast reasonably reflects the capex criteria, and accordingly should be accepted either wholly or in part.

8.6.1.3 Specific approaches adopted to assessing capital expenditure

Benchmarking

Appendix H sets out the AER's approach to benchmarking. In short, the AER does not presently have sufficient data of appropriate quality to comprehensively and conclusively benchmark the capex incurred against that which an efficient DNSP should incur in the circumstances. It is however addressing these issues for future reviews.

However, the AER's data allows for high level comparisons to be made between the DNSPs in the same State and across DNSPs in other States. These comparisons demonstrate that the Victorian DNSPs as a group have lower historical costs on a number of measures of capital and operational expenditure than their peers. The lower costs, however, may be due to any of a number of factors and for this reason must be interpreted with some caution. The lower costs may be due to relative efficiencies (as claimed by each of the Victorian DNSPs) or the acceptance of higher risk (leading to lower historical levels of investment), under-investment, phase in the business cycle, differences in jurisdictional obligations, geographical operating environments or scale efficiencies or a combination of factors. Additionally, it should be recognised that in this comparison even the most relatively efficient DNSP may be some distance away from true efficiency or the efficiency frontier. For these reasons, the AER has been cautious in how it has had regard to the capex factor in clause 6.5.7(e)(4).

Historical expenditure and revealed costs

One significant aspect is the AER's review of historical capex as a point of reference in testing whether forecast future volumes appear consistent with historical activity. Where substantial differences are apparent the AER, either in its own analysis or with the support of Nuttall Consulting, sought to reconcile the reasons given by the DNSPs for those differences with the amounts proposed in the DNSP's revised regulatory proposal. This factor links closely to the AER's use of 'revealed costs' as was discussed in chapter 8 of the draft decision.

Where a business is stable and efficient and its financial controls and its governance and operating policies and procedures are sound, the AER's starting premise is that it is unlikely that past investment decisions would be unsound. Consequently, it follows that the revealed costs of a DNSP are likely to be a reasonable approximation of efficient costs in the circumstances of that DNSP for the volume of work undertaken, ceteris paribus. Further, by testing the volumes of activity undertaken in the past with past forecasts, the AER can and does infer whether or not the forecasting processes employed by a DNSP can reasonably be expected to be an unbiased estimate of future needs. This is consistent with NER clauses 6.5.7(a)(3) and (4), 6.5.7(c)(1) and (2), and clause 6.5.7(e)(1) and (5).

The use of a revealed cost approach is an accepted regulatory practice. This approach has been implicitly accepted by the Victorian DNSPs, as this has been the basis for the capital and operating expenditure proposals of the Victorian DNSPs (except United Energy). This is further noted by the Australian Energy Market Commission (AEMC), in its policy rationale underpinning the economic regulatory framework for transmission in chapter 6A of the NER, which closely mirrors that in Chapter 6. As part of its draft decision in relation to that chapter, the AEMC stated:

> While informed opinions may differ on what are efficient costs, costs of a prudent operator or realistic expectation of forecast demand and input costs in the circumstances facing a regulated entity, those matters can be tested by reference to objective evidence drawn from history…[38]

The AEMC further contemplated the use of the historical/base year approach in developing chapter 6A, stating:

> At the end of the period, the actual costs in this period may be used as a basis for establishing the reasonableness of the cost estimates provided by the TNSP in the subsequent regulatory control period.[39]

The AER accepts that revealed costs alone cannot be used to set future capital and operating expenditure allowances. Revealed costs can assist the AER in a number of ways, including understanding the accuracy of previous forecasts prepared by a DNSP, in testing whether underlying cost estimates are reliable and by providing

[38] AEMC 2006, *Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, Rule Determination*, 16 November 2006, p. 53.

[39] AEMC 2006, *Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, Rule Determination*, 16 November 2006, p. 93.

insight into the outcomes to be expected from the application of a DNSP's internal governance policies and procedures to forecasts. Revealed cost information can inform the assessment of unit costs. It can also assist in establishing a baseline for comparison with the caveat that the allowances determined by the AER will deviate from this baseline when the net effect of the consideration of all the capex factors justifies a different allowance. In particular, the volumes of a particular activity may vary over time for any of a number of sound reasons which must be considered on a case by case basis.

The AER's analysis has sought to explore whether the Victorian DNSPs have been able to adequately explain and substantiate the relative variations in capex volume between their forecasts and their historical expenditure. The capex allowance ultimately determined for many items of expenditure will be the product of the volume forecast and the unit costs considered appropriate for that item. The capex allowances have been set using revealed cost information to test both the past relationship between forecasts and actual outcomes and to set a baseline for unit costs. These components are then combined with the AER's view on justified volumes, cost escalation, margins and overheads to arrive at a view for a particular item of expenditure, taking into account the rest of the capex factors. Although revealed costs have a substantial role in this process, the process also involves consideration of the other applicable capex factors in coming to an overall view.

The approach taken by the AER to the application of the capex factors to the analysis of each sub-category of capex was tailored depending on the nature of each sub-category. For example, reinforcement expenditure can be significantly influenced by the demand forecast or by the known or expected 'pressure points' in the current network and by unpredictable events such as connection applications by major customers. Replacement expenditure, on the other hand, is strongly related to influences such as the age and condition of assets and the ability of the organisation to maintain or extend plant life. Some capex may arise from the imposition of new, or changes to existing obligations. This has been the case for the Victorian DNSPs, with changes to Victoria's regulations governing vegetation management coming into effect. Additionally, the recommendations stemming from the Victorian Bushfire Royal Commission have changed the safety obligations and reporting requirements for the Victorian DNSPs. The AER has worked closely with ESV to ensure a coordinated response to these recent changes. This is discussed in further detail in section 8.6.2.

To assist the AER in the investigation of replacement expenditure proposals the AER has employed a new tool – the repex model. The AER, in determining whether it is satisfied that the forecast capex reasonably reflects the capex criteria in clause 6.5.7(c) of the NER must have regard to, among other matters, analysis undertaken by it or on its behalf. Models such as the repex model are established practice in other regulatory regimes, most notably Ofgem in the UK and various forms of these have also been used by the Victorian DNSPs themselves. This tool is intended to independently test whether the volumes of replacement activity for an asset category are consistent with broad assumptions about asset age and condition. The AER's repex model is not a substitute for the detailed technical analysis and the skilled application of technical judgement to estimating future needs. It is a benchmarking tool which estimates a quantity of replacement activity that might be expected given a population of assets of a particular type and age.

The primary use of the repex model is to identify for further investigation the categories of asset replacement expenditure where the volumes proposed for replacement are significantly greater than the model alone would suggest. Where the volumes predicted by the repex model are found to be consistent with the volumes proposed by a DNSP, prima facie, having considered other capex factors, the particular forecast should be considered reasonable and appropriate. However, there are may be valid reasons why higher volumes of replacement of a specific type of asset may be justified and the AER has been cognisant in this analysis of the need to examine those reasons before finalising a view as to the appropriate levels of expenditure in each asset category.

In response to the AER's draft decision some submissions objected to the AER's development of the repex model and revealed cost approach and noted the potential for regulatory inconsistency because it appeared the AER had taken a different approach to its capex analysis in Victoria, vis-à-vis other jurisdictions.[40]

Submissions made by CitiPower, Powercor and Energy Australia objected to the use of the repex model approach, stating it was unsuitable for regulatory decision making and that the application of revealed costs to forecast capex allowances was unsound.[41] Energy Australia and Grid Australia asserted that the AER's approach to this set of distribution determinations was not consistent with earlier decisions by the AER, and the AER should improve the transparency and predictability of its decision making.[42] In particular, Energy Australia stated that the AER had developed new approaches and tests without consulting stakeholders and relied on analysis that had not been published as part of its draft decision.

In their revised regulatory proposals, CitiPower and Powercor stated that the imposition of an 'evidentiary threshold' (request for cost benefit analysis) by the AER was unduly onerous and demanding and ignore the difficulties that confront a regulated business in a price review process.[43] The AER does not agree it has imposed any inappropriate evidentiary thresholds (perceived or otherwise) and has only sought information to the extent it considers was necessary to determine whether it is satisfied a Victorian DNSP's proposed forecast capex reasonably reflects the capex criteria. The AER has considered these issues in more detail in appendix P.

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40 CitiPower, Powercor, *Submission to the AER - Victorian Bushfire Royal Commission – Implications of the Final Report for the EDPR*, 19 August 2010, pp. 1-3; Grid Australia, *Submission to the AER*,19 August 2010, pp. 1-2, 4-5; Energy Australia, *Submission to the AER*, 19 August 2010, pp. 1-8.

41 CitiPower, Powercor, *Submission to the AER - Victorian Bushfire Royal Commission – Implications of the Final Report for the EDPR*, 19 August 2010, pp. 1-3; Energy Australia, *Submission to the AER*, 19 August 2010, pp. 1-8.

42 Grid Australia, *Submission to the AER*, 19 August 2010, pp. 1-2, 4-5; Energy Australia, *Submission to the AER*, 19 August 2010, pp. 1-8.

43 CitiPower, *Revised regulatory proposal*, October 2010, pp. 253–257; Powercor, *Revised regulatory proposal*, pp. 243–246.

Conversely, the AER also received submissions from EUAA, CALC, CUAC, Origin, EUCV and TRU Energy that were supportive of the AER's approach to the analysis of capex in the draft decision.[44]

Relative prices of and substitutability of capital and operating inputs

The relative prices of capital and operating inputs are considered in some detail by the AER and its advisers. Capital and operating costs estimates are examined by the technical consultant whilst the AER obtains specialist advice on labour cost escalation (set out in appendix K). The AER has also continued its practice of separately reviewing the cost escalation of materials and has incorporated the outcomes of those investigations into the analysis of the capex proposals. The AER's final decision conclusion on cost increases is set out in section 8.6.4.5.

Substitution possibilities between opex and capex can arise in many diverse ways and these are examined as each item of expenditure is individually considered. A major candidate for substitution is reinforcement expenditure where opex in the form of network support or demand-side payments may defer or replace the need for a network augmentation. This consideration is closely aligned to the examination of whether efficient non-network alternatives have been adequately considered. The AER's investigation has examined the supporting documentation for reinforcement capex projects to test whether the Victorian DNSPs appear to have adequately considered this possibility. Also when reviewing items of capex the AER has considered whether the Victorian DNSPs are cognisant of the incentives provided by the STPIS to maintain supply reliability.

The examination of related party arrangements has been undertaken for each DNSP. The analysis is presented separately in chapter 6. The AER has broken down the cost estimates provided by the Victorian DNSPs to identify whether related party margins have been included in the proposed future costs. The AER's final decision conclusion on margins is set out in section 8.6.4.2.

8.6.1.4 Conclusion

Overall, these are some of the considerations the AER has taken into account to determine whether it is satisfied that the forecast capex reasonably reflects the capex criteria listed in clause 6.5.7(c) of the NER. The preceding discussion is illustrative of the analysis undertaken by the AER but is not intended to be exhaustive. The analysis of specific items of capex is discussed in more detail in the relevant sections of appendix P.

Where the AER has not been satisfied that the DNSPs' capex forecast reasonably reflects the capex criteria, the AER can not accept the capex forecast, and must substitute its estimate of the required capex.[45] However as noted earlier, in doing so the AER must only modify the DNSP's proposal to the extent necessary to achieve compliance with the NER.[46] Moreover, the decision the AER is required to make is to

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[44] EUAA, *Submission to the AER*, 19 August 2010, pp. i-ii; CALC, *Submission to the AER*, 19 August 2010, pp. 3-5, 12-19; CUAC, *Submission to the AER*, 19 August 2010, p.2; Origin, *Submission to the AER*, 19 August 2010, pp. 5-6; EUCV, *Submission to the AER,* August 2010, pp. 15-25; TRU Energy, *Submission to the AER,* 16 August 2010, p.2

[45] NER, clause 6.5.7(d) and 6.12.1(3)

[46] ibid, clause 6.12.3(f)

determine if the *total* forecast capex is sufficient to meet the needs of an efficient and prudent DNSP in the circumstances of the regulated DNSP to satisfy the capex objectives.[47] In exercising this discretion the AER must, in accordance with section 16(2) of the NEL have regard to the revenue and pricing principles set out in section 7A of the NEL.

In particular, the setting of the capex allowance most directly involves consideration of revenue and pricing principles 7A (2), (3), (6) and (7). The AER must, amongst other things, ensure that the DNSP is given a reasonable opportunity to recover at least the efficient costs of providing direct control services and complying with all regulatory obligations or requirements. In addition, the DNSP should be provided with effective incentives to provide network services efficiently. The AER must also have regard to whether the allowance proposed gives rise for potential for under or over investment in the network, or for under or over utilisation of the network.

As it is generally (but not always) the case that a network will be operating at close to some equilibrium point between demand and capacity, the risk that a network will be under or over utilised is less likely to emerge in the short-term, than is the risk of under or over investment. Conversely though, over or under investment in a network may result in a shift in the equilibrium point leading subsequently to under or over utilisation of the network. Moreover, it will be the case that under investment will lead to potential disruption of services and the consequent costs must be considered relative to the costs of over investment. Where any residual doubt exists as to the true costs which should apply to a particular allowance then, the AER must balance these considerations to arrive at a final view.

8.6.2 Forecasts for reliability and quality maintained (RQM) capex programs resulting from the Victorian Bushfire Royal Commission (VBRC)

In the draft decision, the AER noted that the Victorian Government had established the VBRC to investigate the February 2009 bushfires. After the draft decision, on 31 July 2010, the VBRC issued its final recommendations to the Victorian Government who in turn announced its intended response. The VBRC made significant recommendations that include increased activities by the Victorian DNSPs to reduce the risks of future bushfires arising from electricity assets.[48]

The draft decision recognised that implicit in the Victorian DNSPs' initial regulatory proposals, particularly in their proposed forecast capex, were a range of current and future activities that may impact on future bushfire risks, even if the purpose of the activity was not primarily that of fire risk reduction.[49] For Powercor and SP AusNet, the AER accepted there was a case, consistent with forecast capex that reasonably reflects the capex criteria, for proposed capex to renew overhead line assets, including those in bushfire prone areas. On the other hand, similar proposals made by JEN and United Energy, in respect of overhead line assets, particularly SWER lines, did not demonstrate such a case.

[47] ibid, clause 6.5.7(c) & (d) and 6.12.1(3)

[48] Victorian Bushfires Royal Commission, *Final Report*, 31 July 2010.

[49] AER, *Draft decision*, June 2010, pp. 292–293.

The Victorian DNSPs originally proposed that uncertainty about the VBRC's recommendations or the Government's response, may be best dealt with as a cost pass through application at a later date. Subject to the requirements of approving cost pass throughs in clause 6.6.1 of the NER, the AER agreed with this approach in principle.

However, the AER is aware that the Victorian DNSPs are presently subject to a number of recently enhanced regulatory requirements which relate to the maintenance of a safe operating environment for electricity distribution assets. Under Victorian legislation, the Victorian DNSPs are now required to have Electrical Safety Management Schemes (ESMS), which are to be monitored by ESV.[50] The Victorian DNSPs are also required to have detailed vegetation management schemes in place, the details of which are discussed in chapter 6. Subsequent to the draft decision, the AER met with ESV and the Victorian DNSPs to establish a coordinated assessment process for safety driven expenditure under the amended Victorian legislation.

It is important to recognise that bushfire safety is a substantial, but not the sole consideration in this process. Other considerations include all proposed safety related expenditure which would subsequently be documented in appropriate instruments, including the Electrical Safety Management Schemes to be monitored by the ESV. The process established by the AER and ESV working conjointly, reviewed proposed capex, established whether safety was a primary driver of the proposed expenditure and if so, the ESV's view on the appropriate volume and timing of the proposed activity. The ESV's advice to the AER is documented in its report dated 14 September 2010.[51] The AER has taken this advice into account in reaching its own view of the applicable volumes of each activity listed therein. Importantly, as required by the NER, the AER with input from its consultant, Nuttall Consulting, remained responsible for reviewing the costs associated with each activity.

For JEN, SP AusNet and United Energy this process has led to substantial step change increases in a number of capex related activities. CitiPower and Powercor did not propose capex step changes under this arrangement, evidently on the basis that it expects that the Victorian Government will introduce further requirements on all the Victorian DNSPs which may require a modified response that is better dealt with as a cost pass through. As noted above, subject to the requirements of clause 6.6.1 of the NER, the AER agrees that if the Victorian Government formally introduced specific legislation, regulations or similar binding regulatory obligations, costs incurred by the Victorian DNSPs, in principle may be dealt with as a cost pass through.

In the draft decision, the AER expressed concern that Powercor and SP AusNet may not be able to accurately target their expanded safety related overhead conductor expenditure.[52] Accordingly, the AER applied a discount factor in its draft decision which both Powercor and SP AusNet did not accept in their revised regulatory proposals. In view of the ESV’s prospective powers to monitor and report on the progress of safety related activities of all the Victorian DNSPs under their vegetation management and Electrical Safety Management Schemes obligations, the AER is no

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50 *Electricity Safety (Management) Regulations* 2009, S.R. No. 165/2009; *Electricity Safety (Electric Line Clearance) Regulations 2010*, S.R. No. 47/2010

51 Energy Safe Victoria, Assessment by Energy Safe Victoria of EDPR Safety-related programs.

52 AER, *Draft decision*, June 2010, pp. 283–284.

longer concerned that any risk will remain of this capex activity being poorly targeted. For this reason, no discount will apply in the final decision.

The AER's view of safety related capex for each Victorian DNSP is detailed in appendix P. The principal driver of much of this activity has led to a step increase in replacement activity for safety related reasons. These issues are now discussed in the environment, safety and legal capex category and not the reliability and quality maintained capex category.

8.6.3 Forecasts for RQM capex resulting from the AECOM climate change report

In the draft decision the AER stated that:

> ‘The AER considers that while it is likely that there is some prospect that the claimed effects [of climate change] will become significant over time, a particular concern is that the AECOM reports adopt climate change models that attempt to measure the impact of events over the next few decades to forecast effects likely in the near term. The models adopted are not fit for short term forecasting and the claimed effects have been rejected on this basis’[53]

and:

> ‘Further, the AECOM reports do not demonstrate any material shifts in asset ageing or deterioration nor in operating conditions sufficient to materially alter the expected future demand or power system capability in the forthcoming regulatory control period. That being said, the AER considers that the effects of climate change on the DNSPs will continue to emerge progressively over time. As circumstances change, there will be measured responses by the DNSPs in their planning and operating procedures which, over time, will cause the technical and financial effects to crystallise. Therefore, the AER considers any climate change effects on the DNSPs will be gradual and may be dealt with progressively as they arise in future regulatory control periods.’[54]

In response to the draft decision, United Energy submitted a response from AECOM. This response sought to address the AER’s concerns regarding the AECOM modelling which was submitted with the initial regulatory proposals.[55] In particular, the response attempted to demonstrate that the scenarios modelled by AECOM are within the range of plausible climate outcomes in the 2011–15 regulatory control period and invites the AER to infer from this basis that these scenarios are likely to occur. Further, the AECOM response supports the proposition that because of climate change effects, there will be future changes in relevant technical design standards and operating practices.

The AER accepts that AECOM's scenarios are plausible. The AER considers that the AECOM models, which measure the impact of climate change effects, are suitable for establishing a range of plausible scenarios for broad consideration of potential impacts but are not suitable for short term forecasting of likely impacts in the 2011–15 regulatory control period. Further, the costs and benefits of an immediate change in

53 AER, *AER draft decision*, p. 293
54 ibid., p. 293.
55 United Energy, *Revised regulatory proposal*, appendix C-14

technical design and operation practices have not been established. In particular, engineering standards and practices are under constant review and will be subject to change over time to adapt to climate change effects just as they adapt to the myriad of other circumstances that may change. Overall, the impacts of climate change, have been, and will continue to occur progressively over time and the financial impacts on the Victorian DNSPs have been occurring already and are therefore captured within the baseline of existing expenditures.

Significantly, the modelling does not establish with certainty that any particular modelled scenario has a higher or lower probability of eventuating. Accordingly, simply being plausible is not persuasive in this regard. In particular, the AER is not persuaded that the effects of climate change and consequent changes in technical design standards are imminent. There is nothing to suggest in the AECOM response that a relevant industry standards body or any other competent authority was actively pursuing changes to technical design standards applicable to the Victorian DNSPs during the 2011–15 regulatory control period. If this was the case, the pursuit of such changes may have permitted any relevant impacts to be costed and be assessed as part of forecast capex.

For the purposes of its assessment under clause 6.5.7 of the NER, the AER does not consider that a prudent operator would unilaterally propose to implement a set of amended or new technical design standards without detailed consideration of the cost-benefit trade-offs for any decisions made as an interim measure in the absence of any persuasive reason to do so. There are therefore insufficient grounds to support a step change in capex for potential climate change effects. Such a step change would not be consistent with forecast capex that reasonably reflects the capex criteria.

Accordingly, in this final decision, the AER maintains its view set out in the draft decision, that no additional allowance for step changes for potential climate change effects are to be included in forecast capex.

8.6.4 AER view on margins, overheads and cost increases

The AER's assessment of each capex category is based on direct costs and excludes the Victorian DNSPs' forecasts of related party margins, overheads and real cost increases. In its draft decision, the AER undertook a separate assessment of the Victorian DNSPs’ proposed related party margins, overheads and real cost increases. It then applied its assessment to these elements of capex to the total draft decision capex allowance for each Victorian DNSP. Similarly, in its final decision, the AER has assessed the Victorian DNSPs’ allowances for related party margins, overheads and real cost increases in their revised regulatory proposals and then applied its assessment on these elements of capex to the total final decision capex allowance for each Victorian DNSP. The following sections outline the AER's final decision on related party margins, overheads and real cost increases for each Victorian DNSP.

In their revised regulatory proposals, CitiPower, Powercor, JEN and SP AusNet proposed forecast capex for the forthcoming regulatory control period that include allowances for margins paid to related party service providers, direct and indirect overheads and real cost increases.[56] In its revised regulatory proposal, United Energy

[56] Refer to chapter 6 of this final decision for further details.

only included an allowance for real cost increases in its proposed forecast capex, as its forecasts are heavily based on outsourced contracts.[57]

The breakdown of the Victorian DNSPs' forecast capex proposals into gross direct capex, overheads, cost increases, margins and customer contributions identified are shown in table 8.8 to 8.12 below. This has been produced based on the regulatory templates in the regulatory information notice (RIN) submitted in the Victorian DNSPs' revised regulatory proposals.

Table 8.8 CitiPower's proposed gross capex, overheads, cost increases, margins and customer contributions ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	448.3	140.3	146.2	156.9	151.7	137.9	733.0	64%
Direct overheads	53.0	11.9	12.0	12.0	11.8	11.4	59.1	12%
Indirect overheads	51.9	12.0	12.1	12.2	12.0	11.7	59.9	15%
Cost increases	7.1	14.7	20.1	25.1	26.3	26.2	112.4	—
Margins	24.8	7.2	7.7	8.3	8.9	8.0	40.2	62%
less Contributions	103.6	9.6	10.9	11.0	11.7	12.3	55.4	-46%
Total net capex	**481.5**	**176.5**	**187.2**	**203.6**	**199.0**	**182.8**	**949.1**	**97%**

Source: CitiPower, *Revised Regulatory Proposal*, RIN template 2.1.
Note: *CitiPowers's cost increase estimate is for 2010 only.
Numbers may not total due to rounding.

[57] Refer to appendix K for further details.

Table 8.9 Powercor's proposed gross capex, overheads, cost increases, margins and customer contributions ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	1050.7	280.9	285.5	285.2	289.7	288.1	1429.3	36%
Direct overheads	21.4	6.0	6.0	5.9	5.8	5.8	29.5	38%
Indirect overheads	97.3	20.0	20.1	20.2	20.0	20.0	100.4	3%
Cost increases	13.9	28.0	36.5	42.0	46.2	50.6	203.4	—
Margins	29.7	11.9	11.9	12.0	13.9	13.3	63.0	112%
less Contributions	282.7	42.2	43.2	44.1	44.6	45.1	219.2	-22%
Total net capex	**930.3**	**304.8**	**316.7**	**321.3**	**331.0**	**332.6**	**1606.3**	**73%**

Source: Powercor, *Revised Regulatory Proposal*, RIN template 2.1.
Note: *Powercor's cost increase estimate is for 2010 only.
Numbers may not total due to rounding.

Table 8.10 JEN's proposed gross capex, overheads, cost increases, margins and customer contributions ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	338.5	104.9	115.5	102.4	95.9	104.3	523.0	55%
Direct overheads	46*	13.8*	15*	14*	13.7*	14.6*	71.1*	55%
Indirect overheads	—	—	—	—	—	—	—	—
Cost increases	0.0	2.9	4.3	5.6	6.3	7.6	26.6	—
Margins	—	—	—	—	—	—	—	—
less Contributions	45.9	7.2	7.2	8.1	7.9	8.5	38.8	-15%
Total net capex	**338.6**	**114.5**	**127.5**	**113.9**	**108.0**	**118.0**	**581.9**	**72%**

Source: JEN, *Revised Regulatory Proposal*, RIN template 2.1.
Note: * Due to JEN’s claims for confidentiality, JEN’s direct overheads, indirect overheads and related party margins have been aggregated into direct overheads.

Table 8.11 SP AusNet's proposed gross capex, overheads, cost increases, margins and customer contributions ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	938.8	255.3	276.4	271.8	243.6	261.7	1308.8	39%
Direct overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—
Indirect overheads	153.4	36.0	39.5	40.6	35.5	42.1	193.7	26%
Cost increases	0.0	7.0	13.2	15.7	18.7	24.4	79.0	—
Margins	2.3	0.0	0.0	0.0	0.0	0.0	0.0	-100%
less Contributions	120.2	10.2	10.0	9.4	8.9	9.2	47.7	-60%
Total net capex	**974.3**	**288.1**	**319.1**	**318.8**	**288.9**	**318.9**	**1533.8**	**57%**

Source: SP AusNet, *Revised Regulatory Proposal*, RIN template 2.1.

Table 8.12 United Energy's proposed gross capex, overheads, cost increases, margins and customer contributions ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	577.5	206.9	208.5	195.1	163.3	142.6	916.4	59%
Direct overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—
Indirect overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—
Cost increases	0.0	8.0	7.4	5.6	6.1	5.9	33.0	—
Margins	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—
less Contributions	68.5	27.7	27.1	26.5	26.8	26.0	134.0	96%
Total net capex	**509.1**	**187.2**	**188.8**	**174.2**	**142.6**	**122.5**	**815.4**	**60%**

Source: United Energy, *Revised Regulatory Proposal,* RIN template 2.1.

8.6.4.2 Related party margins

In chapter 8 of the draft decision, the AER considered that the margins both of a capital and non-capital nature for all related party transactions proposed by CitiPower, Powercor, JEN and SP AusNet had not been adequately justified as prudent and efficient.[58] Accordingly, the AER was not satisfied that any related party margins reasonably reflected the capex criteria and excluded all related party margins from the forecast capex allowance. This assessment had regard to capex factor (9).

SP AusNet and United Energy did not propose a related party margin in relation to its capex forecast.

[58] AER, *Draft decision*, June 2010, p. 297.

In their revised regulatory proposals CitiPower, Powercor and JEN included an allowance for related party margins in their proposed forecast capex, outlined in table 8.13.

Table 8.13 Victorian DNSPs' proposed related party margins ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	24.8	7.2	7.7	8.3	8.9	8.0	40.2	62%
Powercor	29.7	11.9	11.9	12.0	13.9	13.3	63.0	112%
JEN	—	—	—	—	—	—	—	—
SP AusNet	2.3	0.0	0.0	0.0	0.0	0.0	0.0	-100%
United Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—

Source: CitiPower, *Revised Regulatory Proposal*, RIN templates 2.1, Powercor, *Revised Regulatory Proposal*, RIN template 2.1, JEN, *Revised Regulatory Proposal*, RIN template 2.1, SP AusNet, *Revised Regulatory Proposal*, RIN templates 2.1, United Energy, *Revised Regulatory Proposal*, RIN templates 2.1.

Note: Due to JEN's claims for confidentiality, JEN's proposed related party margins have not been separately identified.

In their revised regulatory proposals, CitiPower and Powercor contested the exclusion of margins payable under their Corporate Services Agreement with CHED Services, Network Services Agreement with PNS and Electrical Network Communications Agreement and Corporate Communications Agreement with Silk Telecom.[59]

In JEN's revised regulatory proposal, it stated that the AER's proposed treatment of contracts that fail the presumption threshold has fundamental shortcomings and is inconsistent with the prior regulatory decisions and with other aspects of the draft determination.[60]

In SP AusNet's revised regulatory proposal, it stated that it did not agree with the approach to exclude related party margins for capex. However, SP AusNet did not include any forecast for related party costs or margins, noting that it had not determined how much and what type of work would be allocated to a related party.[61]

The AER has assessed the revised regulatory proposals for related party margins for capex and opex in chapter 6. The AER was not satisfied that any related party margins reasonably reflected the capex criteria and excluded all related party margins from CitiPower's, Powercor's and JEN's forecast capex allowance. Table 8.14 outlines the AER's final decision on related party margins for capex.

[59] CitiPower, *Revised regulatory proposal*, p.134; Powercor, *Revised regulatory proposal*, p.125.
[60] JEN, *Revised regulatory proposal*, p.71.
[61] SP AusNet, *Revised regulatory proposal*, p.89.

Table 8.14 AER conclusion on related party margins ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	0.0	0.0	0.0	0.0	0.0	0.0
Powercor	0.0	0.0	0.0	0.0	0.0	0.0
JEN	0.0	0.0	0.0	0.0	0.0	0.0
SP AusNet	0.0	0.0	0.0	0.0	0.0	0.0
United Energy	0.0	0.0	0.0	0.0	0.0	0.0

8.6.4.3 Direct overheads

In the draft decision, the AER considered that historical direct overheads incurred provides a reasonable starting point to forecast direct overheads for the forthcoming regulatory control period.[62] On this basis, where the DNSP has forecast direct overheads, the AER adjusted the proposed direct overheads as a percentage of direct costs, greater than historical levels.

SP AusNet and United Energy did not seek an allowance for direct overheads.

CitiPower, Powercor and JEN included an allowance for direct overheads in their revised forecast capex proposals, as shown in table 8.15.

Table 8.15 Victorian DNSPs' proposed direct overheads ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	53.0	11.9	12.0	12.0	11.8	11.4	59.1	12%
Powercor	21.4	6.0	6.0	5.9	5.8	5.8	29.5	38%
JEN	—	—	—	—	—	—	—	—
SP AusNet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—
United Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—

Source: CitiPower, *Revised Regulatory Proposal*, RIN templates 2.1, Powercor, *Revised Regulatory Proposal*, RIN template 2.1, JEN, *Revised Regulatory Proposal*, RIN template 2.1, SP AusNet, *Revised Regulatory Proposal*, RIN templates 2.1, United Energy, *Revised Regulatory Proposal*, RIN templates 2.1.

Note: Due to JEN's claims for confidentiality, JEN's proposed direct overheads have not been separately identified.

CitiPower, Powercor and JEN accepted the AER's approach to calculating direct overheads. Conversely, SP AusNet submitted that the AER's 50/50 split of overheads into direct and indirect was arbitrary and unjustified, and in its revised regulatory

[62] AER, *Draft decision*, p. 298.

proposal SP AusNet did not propose any direct overheads, submitting it was not able to split overheads between direct and indirect overheads.[63]

The AER has maintained its approach from the draft decision to calculate direct overheads proposed by CitiPower, Powercor and JEN.

The AER accepts that SP AusNet is not able to split overheads between direct and indirect overheads. Therefore, the AER has not made the 50/50 split used in the draft decision and no allocation has been made for direct overheads for SP AusNet. Table 8.16 outlines the AER's final decision on direct overheads for capex.

Table 8.16 AER conclusion on direct overheads ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	9.5	10.3	11.2	10.9	10.8	52.7
Powercor	4.6	5.4	5.4	5.6	5.6	26.6
JEN	1.6	1.8	1.8	1.9	1.7	8.9
SP AusNet	0.0	0.0	0.0	0.0	0.0	0.0
United Energy	0.0	0.0	0.0	0.0	0.0	0.0

8.6.4.4 Indirect overheads

In the draft decision, the AER considered that it was reasonable to allow for indirect overheads in forecast capex for CitiPower, Powercor, JEN and SP AusNet.

The indirect overheads sought by CitiPower, Powercor, JEN and SP AusNet in their revised regulatory proposals are summarised in table 8.17. United Energy did not seek an allowance for indirect overheads in their revised regulatory proposal.

[63] SP AusNet, *Revised regulatory proposal*, October 2010, pp. 90–91.

Table 8.17 Victorian DNSPs' revised regulatory proposal for indirect overheads ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	51.9	12.0	12.1	12.2	12.0	11.7	59.9	15%
Powercor	97.3	20.0	20.1	20.2	20.0	20.0	100.4	3%
JEN	—	—	—	—	—	—	—	—
SP AusNet	153.4	36.0	39.5	40.6	35.5	42.1	193.7	26%
United Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—

Source: CitiPower, *Revised Regulatory Proposal*, RIN templates 2.1, Powercor, *Revised Regulatory Proposal*, RIN template 2.1, JEN, *Revised Regulatory Proposal*, RIN template 2.1, SP AusNet, *Revised Regulatory Proposal*, RIN templates 2.1, United Energy, *Revised Regulatory Proposal*, RIN templates 2.1.

Note: Due to JEN's claims for confidentiality, JEN's proposed indirect overheads have not been separately identified.

To determine the indirect overheads for the forthcoming regulatory control period, the AER has taken the 2009 capitalised operating expenditure and escalated for growth and real price increases for CitiPower, Powercor, JEN and SP AusNet.

In relation to capitalising operating expenditure overheads to calculate direct overheads, CitiPower and Powercor raised the following issues in their revised regulatory proposals:

- the AER rejected CitiPower's and Powercor's proposed indirect overheads but applied a similar step change decrease in standard control opex due to increased capitalisation of overheads
- the AER applied the adjustment to indirect overheads only, but it should have applied the adjustment proportionally across indirect and direct overheads
- the AER made a one-off adjustment to the 2009 base year cost which effectively assumes that the adjustment is equal in each year of the regulatory control period, however, the amount of the adjustment should vary in each year of the regulatory control period as the ratio of capex to total cost changes
- the AER does not appear to have adjusted the amount proposed by CitiPower and Powercor for related party margins.[64]

The AER acknowledges that it adopted CitiPower's and Powercor's step change decrease to the base year for capitalised overheads (that is a reduction in base year opex) which was decoupled from CitiPower's and Powercor's forecast capex and opex from which this step change was derived. The AER is cognisant that CitiPower and Powercor have stated that they have not changed their capitalisation policies over the forthcoming regulatory control period.

[64] CitiPower, *Revised regulatory proposal*, p.183; Powercor, *Revised regulatory proposal*, p.173.

The AER accepts CitiPower's and Powercor's arguments that the step change reduction in capitalised overheads would under compensate CitiPower and Powercor. Accordingly, the AER has removed the base year adjustment from the draft decision. The AER acknowledges the issues raised by CitiPower and Powercor in the capitalisation of indirect overheads. For this reason there has been no further capitalisation of operating expenditure overheads in its calculation of indirect overheads for the final decision.

JEN has accepted the AER's draft decision approach to calculating indirect overheads. JEN's revised regulatory proposal included 2009 regulatory account data for direct and indirect overheads and applied input cost escalation for labour and materials over the forecasting period.[65]

SP AusNet stated in its revised regulatory proposal that it considered that the AER has incorrectly exercised its discretion in relation to its treatment of the adjustments, in a manner inconsistent with the NER. With regard to the 50/50 split of overheads into direct and indirect, SP AusNet considered it to be purely arbitrary and not justified. SP AusNet noted that at no stage throughout the regulatory process did the AER provide a definition of 'indirect' versus 'direct' overheads.[66]

The AER accepts that SP AusNet has been unable to split overheads between indirect and direct overheads. In reviewing SP AusNet's regulatory accounting statements, the AER accepts that SP AusNet has not changed its capitalisation policy. Therefore, in the final decision the AER has not made the 50/50 split between direct and indirect overheads, and has included total overheads for SP AusNet under indirect overheads.

The AER maintains its position in the draft decision that it is reasonable to allow for indirect overheads in forecast capex. The AER has therefore 'rolled forward' CitiPower's, Powercor's, JEN's and SP AusNet's total capitalised overheads as reported in their 2009 regulatory accounts exclusive of related party margins (and as reported in their respective RINs) to determine the 'base' forecast amounts for each year of the forthcoming regulatory control period. The AER has also applied scale and real cost escalation to the 'base' forecast amount to determine CitiPower's, Powercor's, JEN's and SP AusNet's total forecast for indirect overheads over the forthcoming regulatory control period. For SP AusNet, this amount includes direct and indirect overheads.

The AER has made an allowance for indirect overheads in its final decision on capex for CitiPower, Powercor, JEN and SP AusNet consistent with the approach described above, which it considers to be the minimum adjustment necessary to reasonably reflect the capex criteria. This assessment has taken into account capex factors (1), (2) and (3). The AER's conclusion on indirect overheads is summarised in table 8.18.

65 JEN, *Revised regulatory proposal*, p.194.
66 SP AusNet, *Revised regulatory proposal*, p.91.

Table 8.18 AER conclusion on indirect overheads ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	11.6	11.9	12.2	12.5	12.8	61.0
Powercor	20.1	20.5	21.1	21.9	22.4	106.0
JEN	2.6	2.6	2.7	2.7	2.8	13.4
SP AusNet	35.9	36.6	37.5	39.3	40.0	189.3
United Energy	0.0	0.0	0.0	0.0	0.0	0.0

Note: SP AusNet's overheads include direct and indirect overheads.

8.6.4.5 Real cost increases

The AER's draft decision on each real cost escalator was used to determine an allowance for real cost increases that the AER was satisfied reasonably reflected the efficient costs to achieve the capex criteria including the capex objectives.

In their revised regulatory proposals, the Victorian DNSPs stated they did not accept the AER's draft decision on real cost increases.[67] In their revised regulatory proposals, the Victorian DNSPs have adjusted their capex forecasts to account for real cost increases in key inputs including copper, aluminium, steel, crude oil, construction costs, sector related and general labour costs, shown in table 8.19.

Table 8.19 Victorian DNSPs’ revised regulatory proposal on real cost increases ($’m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total
CitiPower	7.1	14.7	20.1	25.1	26.3	26.2	112.4
Powercor	13.9	28.0	36.5	42.0	46.2	50.6	203.4
JEN	0.0	2.9	4.3	5.6	6.3	7.6	26.6
SP AusNet	0.0	7.0	13.2	15.7	18.7	24.4	79.0
United Energy	0.0	8.0	7.4	5.6	6.1	5.9	33.0

Source: CitiPower, *Revised Regulatory Proposal*, RIN templates 2.1, Powercor, *Revised Regulatory Proposal*, RIN template 2.1, JEN, *Revised Regulatory Proposal*, RIN template 2.1, SP AusNet, *Revised Regulatory Proposal*, RIN templates 2.1, United Energy, *Revised Regulatory Proposal*, RIN templates 2.1.

Note: SP AusNet's *Revised Regulatory Proposal* RIN template 2.1 does not include material escalators. SP AusNet submitted its material escalators to the AER in September 2010.

The AER has assessed the Victorian DNSPs' proposed real cost escalators in appendix K of this final decision. These real cost escalators have been applied to the

[67] SP AusNet, *Revised regulatory proposal*, p. 160 and 162–163; CitiPower, *Revised regulatory proposal*, p. 232; Powercor, *Revised regulatory proposal*, p. 222; JEN, *Revised regulatory proposal*, pp. 188 and 193; United Energy, *Revised regulatory proposal*, p. 83.

direct costs determine the final decision on real cost increases, summarised in table 8.20.

Table 8.20 AER conclusion on real cost increases ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	4.3	6.7	10.2	13.8	16.7	51.7
Powercor	8.7	12.6	17.7	24.9	29.6	93.5
JEN	-0.4	0.2	1.0	2.1	2.5	5.3
SP AusNet	23.2	24.0	27.5	27.4	28.5	130.6
United Energy	6.1	6.0	3.4	4.7	5.6	25.7

8.6.5 Equity raising costs

The Victorian DNSPs accepted the AER's draft decision on equity raising costs in their revised regulatory proposals.[68]

The AER's final decision on benchmark equity raising costs, derived through applying the benchmark cash flow analysis determines that in the forthcoming regulatory control period, an equity raising cost allowance is required for CitiPower, Powercor, SP AusNet and United Energy, while JEN has sufficient retained cash flows for their respective equity requirements. The benchmark equity raising costs allowances for CitiPower, Powercor, SP AusNet and United Energy are shown in table 8.21.

The capex discussion and figures in this chapter are exclusive of equity raising costs. Analysis and discussion of the benchmark equity raising costs is considered in appendix O.

Table 8.21 AER final decision on benchmark equity raising costs for the forthcoming regulatory control period ($'m, 2010)

DNSP	CitiPower	Powercor	SP AusNet	United Energy	Notes
Total equity raising cost	3.0	6.3	1.8	3.7	To be added to the RAB at the start of the forthcoming regulatory control period

Source: AER analysis.

[68] CitiPower, *Revised regulatory proposal*, p. 252; Powercor, *Revised regulatory proposal*, p. 242; JEN, *Revised regulatory proposal*, p. 194; United Energy, Post tax revenue model, July 2010.

8.7 Summary of the AER's final decision on forecast capital expenditure

Figure 8.1 and table 8.22 set out the AER's capex allowance conclusions (at a direct cost level) by capex category for the forthcoming regulatory control period.

Figure 8.1 AER’s capex allowance conclusions for all Victorian DNSPs – direct cost ($’m, 2010)

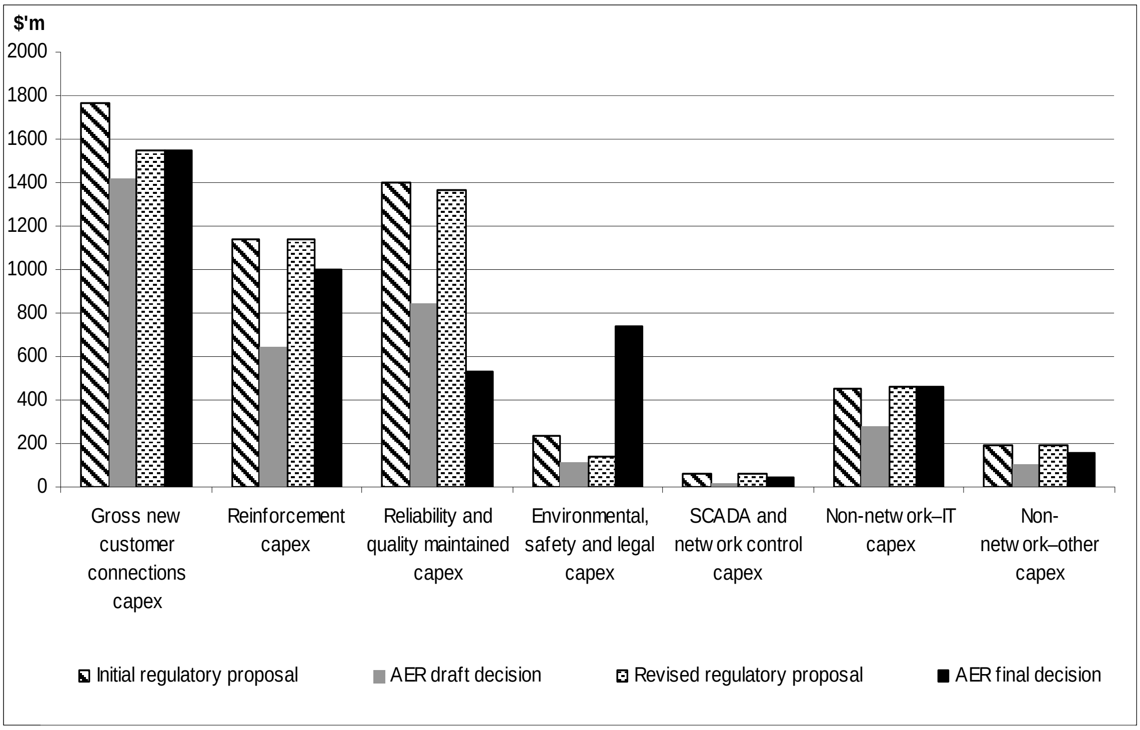

Table 8.22 AER capex allowance conclusions – direct cost ($’m, 2010)

	Initial regulatory proposal	AER draft decision	Revised regulatory proposal	AER final decision
Gross new customer connections capex	1762.4	1421.1	1551.4	1551.4
Reinforcement capex	1140.4	639.2	1136.3	996.1
Reliability and quality maintained capex	1,404.30	841.1	1364.2	530.7
Environmental, safety and legal capex	237.2	112.7	141.0	735.8
SCADA and network control capex	63.9	20.1	59.9	39.3
Non-network IT capex	449.9	278.2	463.3	463.3
Non-network other capex	190.4	104.6	194.6	157.7
Customer contributions	735.1	689.5	495.1	544.3
Total net capex	**4513.4**	**2727.5**	**4415.5**	**3930.0**

In broad terms, compared to the AER’s draft position, overall direct capex is proposed to increase by approximately 44 per cent, to $3.9 billion. This represents a reduction of 13 per cent from the Victorian DNSP’s initial proposals of $4.5 billion, and 11 per cent from the Victorian DNSPs' revised regulatory proposals of $4.4 billion. The significant changes from the AER's draft decision arise from ESV's recommended safety driven capex and more detailed information from the Victorian DNSPs to support the need for expenditure in reinforcement capex, SCADA and network control capex and non-network IT capex.

8.7.2 New customer connections

8.7.2.1 AER approach to assessment

The AER’s draft decision found some issues with the Victorian DNSPs forecasts of gross customer connection capex which have been addressed in the Victorian DNSPs' revised proposals. Customer contributions must be calculated in accordance with Guideline 14 as issued by the Essential Services Commission Victoria.[69] These amounts are deducted from the gross customer connection capex to arrive at the net

69 Essential Services Commission Victoria, *Electricity industry guideline No. 14, Provision of services by electricity distributors.*

amount of customer connection capex. In their initial regulatory proposals, some errors were found in the calculation of customer contributions. In their revised proposals each of the DNSPs addressed the errors in the initial proposal calculation of customer contribution amounts. To account for the AER's final decision on X–factors the AER's final decision on customer contributions has adjusted the Victorian DNSPs' revised proposal calculations of customer contributions to derive the final decision on net customer contribution capex.

8.7.2.2 Summary of revised regulatory proposals

Each Victorian DNSP largely accepted the AER's draft decision on gross new customer connections capex. In their revised regulatory proposals, the Victorian DNSPs made some minor adjustments to gross new customer connections capex reflective of revised economic growth and population forecasts, as shown in table 8.23.

Table 8.23 Victorian DNSPs' new customer connections capex - direct costs ($'m, 2010)

		Initial regulatory proposal	AER draft decision	Revised regulatory proposal
CitiPower	Gross	379.1	197.5	228.6
	Net	206.5	89.0	173.1
Powercor	Gross	673.7	526.6	574.9
	Net	390.6	235.6	355.7
JEN	Gross	138.2	125.6	136.6
	Net	68.7	68.7	97.8
SP AusNet	Gross	357.0	357.0	372.7
	Net	268.0	244.8	325.0
United Energy	Gross	214.4	214.4	238.6
	Net	93.5	93.5	104.6
Total	**Gross**	**1762.4**	**1421.1**	**1551.4**
	Net	**1027.3**	**731.6**	**1056.2**

8.7.2.3 Summary of AER assessment and conclusions

The AER has accepted the Victorian DNSPs' revised regulatory proposals for gross new customer connections capex as being consistent with historical trends and reasonably taking into account revised customer number forecasts. The AER considers that the Victorian DNSPs' revised regulatory proposal for gross new customer connections capex of $1551.4 million, is part of a total forecast capex that reasonably reflects the capex criteria, specifically, to meet the expected demand for standard control services. This assessment has particularly taken into account capex factors (1), (2), (3) and (5) in clause 6.5.7(e) of the NER. As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing gross new customer connections capex, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles.

In their revised regulatory proposals, the Victorian DNSPs have also revised their customer contributions to be consistent with Guideline 14. For customer contributions, the AER has accepted the modelling undertaken by the Victorian DNSPs and has incorporated the AER's final decision on the WACC, the Po, and the X–factor year for each DNSP. The AER considers that the Victorian DNSPs' revised regulatory proposals for customer contributions adjusted for the AER's final decision on WACC, the Po, and the X–factor of $753 million, is part of a total forecast capex that reasonably reflects the capex criteria. As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing customer contributions, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles.

Table 8.24 sets out the AER's final decision on new gross and net new customer connections capex for Victorian DNSPs in the forthcoming regulatory period.

Table 8.24 AER conclusion on new gross and net new customer connections ($’m, 2010)

		2011	2012	2013	2014	2015	Total
CitiPower	Gross	44.6	45.6	45.6	46.1	46.6	228.6
	Net	33.5	33.2	33.1	33.0	32.8	165.7
Powercor	Gross	114.9	114.9	115.0	115.0	115.0	574.9
	Net	67.3	66.7	66.1	65.8	65.4	331.2
JEN	Gross	23.1	23.0	27.7	29.7	33.0	136.6
	Net	15.8	15.7	19.5	21.7	24.3	97.0
SP AusNet	Gross	79.9	78.1	73.8	69.6	71.3	372.7
	Net	65.9	64.5	61.1	57.8	59.2	308.5
United Energy	Gross	49.8	48.7	48.3	46.8	45.0	238.6
	Net	22.2	21.6	21.8	20.1	19.0	104.6
Total	**Gross**	**312.3**	**310.4**	**310.4**	**307.3**	**311.0**	**1551.4**
	Net	**204.6**	**201.8**	**201.6**	**198.3**	**200.7**	**1007.0**

Note: Gross connections capex amounts are at a direct cost level and exclude the AER's final decision on margins, overheads and real cost increases.

8.7.3 Reinforcement

8.7.3.1 AER approach to assessment

In the draft decision, the AER was not satisfied that the Victorian DNSPs forecasts of reinforcement expenditure satisfied the capex criteria. The AER substituted its own forecast for each DNSP, based on a ‘weighted average probability’ assessment approach as suggested by its consultant, Nuttall Consulting. In their revised proposals the Victorian DNSPs each rejected the AER’s approach. After considering the DNSPs’ revised proposals and submissions, the AER accepts that there should be further consideration, including broader consultation with industry and other stakeholders, before the ‘weighted average probability assessment’ is applied to regulatory decisions in such a way. In its final decision, the AER has made adjustments to the Victorian DNSP forecasts of reinforcement capex based on detailed examination of around 30 per cent of each DNSP’s proposed reinforcement expenditure.

8.7.3.2 AER draft decision summary

Taking into account Nuttall Consulting’s detailed methodology and project reviews, the AER in its draft decision found that the proposed reinforcement capex forecasts were not shown to provide a reasonable and efficient forecast of reinforcement capex needs. In the absence of justified increases in reinforcement forecasts, the AER considered that further emphasis should be given to historical trends.

In estimating the required forecast of reinforcement capex that reasonably reflects the capex criteria for each Victorian DNSP, the AER adopted the recommendations by Nuttall Consulting, based on its weighted probability analysis. Table 8.25 outlines the AER's draft decision on reinforcement capex for the Victorian DNSPs for the forthcoming regulatory control period.

Table 8.25 AER draft decision on reinforcement capex for Victorian DNSPs ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	39.6	32.4	36.5	11.2	11.9	131.5
Powercor	26.4	28.1	29.9	31.7	33.7	149.8
JEN	10.1	10.9	11.8	12.7	13.7	59.1
SP AusNet	28.3	31.0	33.8	36.9	40.3	170.3
United Energy	24.7	25.2	25.7	26.2	26.7	128.4

Note: These numbers are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

8.7.3.3 Summary of revised regulatory proposals

The Victorian DNSPs did not accept the draft decision on reinforcement capex and sought to restate their reinforcement capex amounts as per their initial regulatory proposals, as outlined in table 8.26.

Table 8.26 **Victorian DNSPs' reinforcement capex - direct costs ($'m, 2010)**

	Initial regulatory proposal	AER draft decision	Revised regulatory proposal
CitiPower	229.4	131.5	231.2
Powercor	241.5	149.8	236.4
JEN	143.3	59.1	107.1
SP AusNet	321.2	170.3	359.5
United Energy	205.0	128.4	202.2
Total	**1140.4**	**639.2**	**1136.3**

The Victorian DNSPs did not agree with Nuttall Consulting's weighted probability analysis to determine the allowance for reinforcement. Some of the Victorian DNSPs' criticisms of the methodology included that Nuttall Consulting did not take a statistically significant sample of projects into account, and the methodology was subjective and untested. Further, the Victorian DNSPs have not agreed with Nuttall Consulting's conclusions on the use of the Victorian DNSPs of old load profiles, the impact of maximum demand on delaying projects, and Nuttall Consulting's concerns relating to the Victorian DNSPs' lack of detailed economic analysis to support their reinforcement capex proposals.[70]

In terms of the revised regulatory proposals, the Victorian DNSPs have provided further information for those projects reviewed by Nuttall Consulting. For the majority of projects reviewed by Nuttall Consulting, the Victorian DNSPs considered that the further information should justify their expenditure in the forthcoming regulatory control period.

8.7.3.4 Summary of AER assessment and conclusions

Based on the assessment of major augmentation projects and methodologies used to determine each Victorian DNSP's reinforcement capex forecast the AER considers there are a number of issues with the economic justification for the timing of the major sub-transmission projects, and the economic options analysis considered for the proposed reinforcement capex.

In previous regulatory control periods, actual expenditure has been considerably less than what the Victorian DNSPs have originally forecast. The AER considers that the Victorian DNSPs' proposed forecasts do not adequately take account of this factor reflecting the further detailed analysis and refinement of project timing and costs that occurs during the period.

Based on this assessment, the AER is not satisfied that each Victorian DNSP has justified that its forecast of reinforcement expenditure reasonably reflect the efficient

[70] See Appendix P for further details.

cost of achieving the capex objectives, specifically, to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

This assessment is consistent with the capex criteria and the AER approach to assessing reinforcement outlined section in appendix P. In doing so this assessment the AER has also had regard to:

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals
- capex factor (3) – whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting
- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (10) – where the AER has taken into account the extent to which each Victorian DNSP has considered and made provision for efficient, non-network alternatives.

In determining an alternative forecast of reinforcement capex, the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast of reinforcement capex. However, the AER also acknowledges that based on the loading of the Victorian DNSPs' networks that an increase in reinforcement capex is required in the forthcoming regulatory control period.

The AER has considered Nuttall Consulting's detailed review of methodologies used to derive the reinforcement expenditure forecasts and considers that the sample of projects reviewed, is a reasonable representation of the issues that exist across the category of forecast reinforcement capex. The AER has therefore taken into account Nuttall Consulting's findings from its review to determine the prudency and efficiency of the major augmentation projects reviewed. However, the AER considers that Nuttall Consulting's weighted average probability assessment requires further testing to be used as an appropriate methodology to determine a reasonable forecast of reinforcement capex within the requirements of the Rules.

Based on its assessment of the Victorian DNSPs' revised regulatory proposals for reinforcement capex, the AER considers its estimate of $996.1 million is part of a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this estimate reflects the minimum adjustment necessary to comply with clause 6.12.3(f) of the NER. As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing reinforcement capex, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles. Table 8.27 sets out the AER's final decision on reinforcement capex for Victorian DNSPs in the forthcoming regulatory period.

Table 8.27 AER final decision on reinforcement capex for Victorian DNSPs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	44.8	40.6	50.4	39.0	38.0	212.7
Powercor	43.5	44.1	47.9	45.5	49.5	230.4
JEN	12.6	9.5	21.8	31.0	17.5	92.4
SP AusNet	53.0	54.0	64.9	56.4	60.0	288.3
United Energy	35.1	37.3	27.4	31.1	41.4	172.3

Note: These numbers are at a direct cost level and exclude the AER's final decision on margins, overheads and real cost increases.

8.7.4 Reliability and Quality Maintained (RQM)

8.7.4.1 AER approach to assessment

The AER's draft decision found that many of the Victorian DNSPs' proposed RQM capex forecasts were not reasonable and efficient estimates of future replacement needs. The AER's analysis included the application of its repex model to validate the Victorian DNSPs forecasts of RQM. Where a DNSP's forecast RQM was equal to or lower than the AER's analysis, including the repex model outputs, the AER accepted the DNSP's forecast RQM. Where a DNSP's forecast was higher than the AER's analysis, the AER conducted a detailed review to determine if a higher volume had been justified. Where the AER was not satisfied, the AER considered the recommendations of Nuttall Consulting, historical expenditure (i.e. revealed costs) and the repex model outputs in formulating the AER's alternative forecast.

In the final decision, the AER's approach has been to conduct a detailed review of all categories that were not accepted by the Victorian DNSPs. In summary, the AER has reviewed the Victorian DNSPs proposed RQM forecasts and the information accompanying their regulatory proposals to determine if a higher volume had been justified. Where the AER was not satisfied the AER considered the recommendations of Nuttall Consulting and the repex model outputs in formulating the AER's alternative forecast.

Between the draft and final decision, significant changes occurred to the regulatory framework for the safe operation of electricity distribution networks in Victoria. A number of the Victorian DNSPs sought enhanced capex allowances to address aspects of those changes. Consequently, significant volumes of assets previously considered under the RQM category have been transferred to the environment, safety and legal capex category.

8.7.4.2 Summary of revised regulatory proposals

The Victorian DNSPs largely rejected the AER's draft decision on reliability and quality maintained (RQM) capex. The Victorian DNSPs' revised forecasts for RQM capex compared to their initial proposal and the AER's draft decision are shown below.

Table 8.28 Victorian DNSPs' RQM capex - direct costs ($'m, 2010)

	Initial proposal	AER draft decision	Revised regulatory proposal
CitiPower	258	137.2	191.6
Powercor	364.4	256.4	364.4
JEN	151.5	66.5	132.0
SP AusNet	353.2	240.9	401.9
United Energy	277.2	140.1	274.2
Total	**1 404.3**	**841.1**	**1364.2**

The Victorian DNSPs' revised regulatory proposals uniformly submitted that the AER draft decision:

- had placed undue consideration on historical expenditure while ignoring the other NER capex factors
- had not reviewed the relevant DNSP's proposal or supporting information
- was inconsistent with other AER determinations
- had overly relied on its repex model to set future expenditure.

In their revised regulatory proposals, the Victorian DNSPs also objected to the use of the repex model to determine appropriate levels of replacement capex.[71]

8.7.4.3 Summary of AER assessment and conclusions

After reviewing the Victorian DNSPs' initial and revised regulatory proposals, the AER's detailed review placed particular emphasis on:

- the Victorian DNSPs' forecasting methodology – their forecasting models, the inputs and assumptions of these models and the application of these data to form their forecast
- the drivers for capex (such as asset age, risk profiles and asset condition), examining whether the drivers were appropriate, whether the drivers have changed and whether the timing of the expenditure was appropriate
- the outcomes delivered by the Victorian DNSPs in the 2006-10 regulatory period and the potential benefits of the Victorian DNSPs' proposed increase in capex.

This assessment is consistent with the capex criteria and the AER approach to assessing RQM outlined section in appendix P. In doing so this assessment has also had regard to:

71 See appendix P for further details.

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals
- capex factor (2) – taking account submissions received from stakeholders
- capex factor (3) – whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting
- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (5) – taking into account the actual and expected capex, specifically the assets lives achieved in the current period and the volume of asset replacement between historical and forecast
- NEO - assessing whether the proposal would be in the long term interests of consumers.

Following its detailed review of the Victorian DNSPs' revised RQM forecasts, the AER is still not satisfied that the proposed amounts are consistent with a total forecast capex that reasonably reflects the capex criteria. This view is based upon concerns the AER has with:

- certain areas of asset replacement where the Victorian DNSPs have advocated a move away from a business as usual approach to asset replacement
- the lack of evidence of the overall changes to risk levels the Victorian DNSPs face in the forthcoming regulatory control period
- the lack of evidence that many of the models used to develop the forecasts can be considered 'fit for purpose' in terms of producing forecast appropriate for regulatory purposes
- numerous areas where the AER considered overestimation could be occurring
- lack of recognition of synergies or benefits between individual projects and programs and to customers.

Given these issues, the AER also considers that the Victorian DNSPs' forecast capex does not support the NEO, as it is unclear on the evidence available whether this capex constitutes efficient investment in or efficient operation and use of, electricity services for the long term interests of consumers. Further, the AER also considers that the revenue and pricing principles are not satisfied. For example, in the absence of robust information, it cannot be determined whether the costs that will be incurred are efficient such that the Victorian DNSPs should have a reasonable opportunity to recover at least the efficient costs of complying with regulatory requirements, as set out in section 7A(2) of the NEL.

Further, in reviewing the Victorian DNSPs' capital plans, the AER also considers that as the plans advance through the Victorian DNSPs’ capital governance processes, reductions will occur, resulting in the:

- likely the deferral of some projects
- selection of more efficient solutions, or
- decision not to undertake certain projects at all.

In their revised regulatory proposals, the Victorian DNSPs included replacement programs that were primarily driven by safety issues. In reviewing the Victorian DNSPs' proposed safety driven replacement capex programs, the AER requested the assistance of ESV. In consultation with the Victorian DNSPs, the AER and ESV assessed whether there was a primarily safety-driven need for the Victorian DNSPs' proposed works in the forthcoming regulatory control period. The ESV advised the AER on the appropriate volume and timing of the proposed safety driven replacement capex programs.[72] The AER has accepted the ESV's recommendations on required work volumes in the forthcoming regulatory control period. In light of the ESV's findings, a substantial component of the Victorian DNSPs' RQM has been moved and approved under environmental safety and legal capex, resulting in an effective increase in RQM activity relative to historic expenditure levels, as safety related issues are addressed in the forthcoming regulatory control period. The ESV will monitor the Victorian DNSPs' completion of all safety-driven works in the forthcoming regulatory control period.

The AER considers that a reasonable estimate of RQM capex should be relatively consistent with the recent historical level (including 2009 capex) with some modest allowance for increasing needs due to the ageing of the network and further demand growth. The AER also considers that this uplift in the Victorian DNSPs' allowance from the draft decision will also allow the Victorian DNSPs to meet their obligations under the NER.

Based on its assessment of the Victorian DNSPs' revised regulatory proposals for RQM capex, the AER considers that its estimate of $530.5 million is part of a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this estimate reflects the minimum adjustment necessary in order to comply with clause 6.12.3(f) of the NER. As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing RQM capex, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles. Table 8.29 sets out the AER's final decision on RQM capex for the Victorian DNSPs in the forthcoming regulatory period.

72 See in appendix P for further details.

Table 8.29 AER final decision on RQM capex - direct costs ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	20.9	23.5	24.5	27.0	29.2	125.1
Powercor	24.6	25.1	25.7	26.4	27.1	129.0
JEN	8.1	8.4	8.8	10.5	12.1	47.9
SP AusNet	23.6	23.6	23.7	24.1	24.5	119.6
United Energy	26.1	20.9	19.6	20.8	21.6	109.3

Note: These numbers are at a direct cost level and exclude the AER's final decision on margins, overheads and real cost increases.

8.7.5 Environmental, safety and legal

8.7.5.1 AER approach to assessment

In the draft decision, the AER’s assessment was assisted by Nuttall Consulting. Where the AER was not satisfied that a DNSP's proposed environmental, safety and legal capex reasonably reflected the capex criteria, the AER substituted its own forecasts.

Between the draft and final decision, significant changes occurred to the regulatory framework for the safe operation of electricity distribution networks in Victoria. A number of the Victorian DNSPs sought enhanced capex allowances to address aspects of those changes. CitiPower and Powercor did not seek amended capex allowances.

In addition to Nuttall Consulting, the AER enlisted the assistance of Energy Safe Victoria to evaluate whether the proposals of each DNSP were consistent with their safety obligations. The AER’s final decision incorporates the recommendations of Energy Safe Victoria.

8.7.5.2 Summary of revised regulatory proposals

The AER's draft decision on environmental, safety and legal was:

- accepted by SP AusNet
- not accepted by CitiPower, Powercor, JEN and United Energy. JEN and United Energy submitted to restate amounts as per their initial regulatory proposals. CitiPower and Powercor stated they did not contest the AER's draft decision, however, they did not actually accept the draft decision because they considered the AER should include 2009 actual data in its analysis of capex trends and forecast of future capex requirements.

Table 8.30 summarises the AER's draft decision and the Victorian DNSPs' revised regulatory proposals on environmental, safety and legal capex.

Table 8.30 Victorian DNSPs' environmental, safety and legal capex - direct costs ($'m, 2010)

	Initial proposal	AER draft decision	Revised regulatory proposal
CitiPower	16.0	6.0	5.5
Powercor	48.2	33.5	32.3
JEN	27.0	25.0	29.7
SP AusNet	94.9	5.5	5.3
United Energy	51.1	42.7	68.1
Total	**237.2**	**112.7**	**141.0**

The Victorian DNSPs submitted to ESV on projects which they considered to be primarily safety driven. The AER has accepted ESV's recommendations on the required volumes of work that will be completed in the forthcoming regulatory control period. The AER separately assessed the proposed unit costs for the ESV-endorsed projects.

In the revised regulatory proposals, the Victorian DNSPs considered that the information provided should justify their proposed expenditure in the forthcoming regulatory control period.

8.7.5.3 Summary of AER assessment and conclusions

The AER has accepted ESV's recommendations on the Victorian DNSPs' proposed safety driven replacement capex volumes required to be completed in the forthcoming regulatory control period. In assessing the proposed unit costs for the safety driven replacement capex programs, the AER considered the independent views of the Victorian DNSPs and Nuttall Consulting. The AER also assessed JEN's and United Energy's proposed project lists and considered that a number of the proposed projects relate to reinforcement capex or other ongoing activities, rather than primarily being safety driven, and therefore have not be included in the environmental, safety and legal capex allowance.

Based on this assessment, the AER did not accept that each Victorian DNSP has justified that its forecast of environmental, safety and legal expenditure reasonably reflect the efficient cost of achieving the capex objectives, specifically to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

This assessment is consistent with the capex criteria and the AER's approach to assessing environmental, safety and legal capex outlined in appendix P. In doing so, this assessment has also had regard to:

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals

- capex factor (2) – taking into account the submissions received on each Victorian DNSP's regulatory proposals
- capex factor (3) – whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting and ESV
- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (5) – where the AER has taken into account the actual and expected capex of the Victorian DNSPs during any preceding regulatory period.

In determining an alternative forecast of environmental, safety and legal capex, the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast. However, the AER also acknowledges that based on ESV’s assessment of the safety driven projects required in the years 2011–15 that an increase in environmental, safety and legal capex is required in the forthcoming regulatory control period.

The AER has considered the reports of ESV and Nuttall Consulting on safety driven projects and associated unit costs used to derive the environmental, safety and legal expenditure forecasts. The AER considers that this information has provided a reasonable assessment of the proposed environmental, safety and legal expenditure forecasts. The AER has therefore taken into account ESV's and Nuttall Consulting's findings from their reviews to determine the prudency and efficiency of the environmental, safety and legal projects reviewed.

Based on its assessment of the Victorian DNSPs' revised regulatory proposals for environmental, safety and legal capex, the AER considers that its estimate of $735.8 million is part of a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this estimate reflects the minimum adjustment necessary in order to comply with clause 6.12.3(f) of the NER. As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing environmental, safety and legal capex applied here, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles. Table 8.31 sets out the AER's final decision on environmental, safety and legal capex for Victorian DNSPs in the forthcoming regulatory period.

Table 8.31 AER final decision on environmental, safety and legal capex - direct costs ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	5.6	5.8	5.7	6.1	6.2	29.4
Powercor	40.8	41.7	41.9	42.1	42.4	208.9
JEN	16.4	16.6	14.4	14.4	14.2	76.1
SP AusNet	39.5	38.9	45.7	43.2	44.8	212.2
United Energy	44.4	44.8	40.6	39.8	39.5	209.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and the AER's final decision on margins, overheads and real cost increases.

8.7.6 SCADA and network control

8.7.6.1 AER approach to assessment

In the draft decision, the AER’s assessment was assisted by Nuttall Consulting. The AER was not satisfied that a number of the DNSPs' proposed SCADA and network control capex projects reasonably reflected the capex criteria. Where a DNSPs' proposed SCADA and network control capex did not reasonably reflect the capex criteria, the AER substituted its own forecasts.

The Victorian DNSPs submitted additional information in their revised regulatory proposals to address the AER’s concerns with a number of aspects, including SCADA and IT systems and depot redevelopment. In the final decision, the AER has reviewed the revised regulatory proposals in a similar manner to the approach taken in the draft decision to arrive at its final decision conclusion on SCADA and network control capex.

8.7.6.2 Summary of revised regulatory proposals

The AER's draft decision on SCADA and network control was:

- accepted by JEN
- not accepted by CitiPower, Powercor, SP AusNet and United Energy. Each of these DNSPs submitted to restate amounts as per their initial regulatory proposals.

Table 8.32 summarises the AER's draft decision and the Victorian DNSPs' revised regulatory proposals on SCADA and network control capex.

Table 8.32 Victorian DNSPs' SCADA and network control capex - direct costs ($'m, 2010)

	Initial proposal	AER draft decision	Revised regulatory proposal
CitiPower	18.1	4.9	18.0
Powercor	30.6	12.0	30.3
JEN	3.1	3.2	2.8
SP AusNet	7.4	0.0	7.4
United Energy	4.7	0.0	1.5
Total	**63.9**	**20.1**	**59.9**

CitiPower and Powercor did not agree with Nuttall Consulting's assessment that the proposed projects were not required in the forthcoming regulatory control period.[73] Similarly, SP AusNet and United Energy did not agree with the AER's assessment that the proposed projects were not required in the forthcoming regulatory control period.[74]

In their revised regulatory proposals, the Victorian DNSPs considered that the information provided should justify their expenditure in the forthcoming regulatory control period.

8.7.6.3 Summary of AER assessment and conclusions

The AER reviewed CitiPower's, Powercor's, JEN's and SP AusNet's SCADA and network control projects and methodologies. The AER considers there are a number of issues with the economic justification for the proposed SCADA and network control capex.

Based on this assessment, the AER did not accept that CitiPower's, Powercor's, JEN's and SP AusNet's forecast of SCADA and network control capex reasonably reflects the efficient cost of achieving the capex objectives, specifically, to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

The AER's assessment is consistent with the capex criteria and is outlined further in appendix P. The following factors are particularly relevant to this analysis:

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals
- capex factor (2) – taking into account the submissions received on each Victorian DNSP's regulatory proposals

73 CitiPower, *Revised regulatory proposal*; p 313; Powercor, *Revised regulatory proposal*, p 301.

74 SP AusNet, *Revised regulatory proposal*, pp. 139–140; United Energy, *Revised regulatory proposal*, p. 145.

- capex factor (3) – whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting

- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP

- capex factor (5) – where the AER has taken into account the actual and expected capex of the Victorian DNSPs during any preceding regulatory period.

In determining an alternative forecast of SCADA and network control capex the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast of SCADA and network control capex. However, the AER also acknowledges that based on requirements to upgrade technology an increase in SCADA and network control capex is required in the forthcoming regulatory control period.

The AER has had regard to Nuttall Consulting's reports on SCADA and network control projects. The AER has taken into account Nuttall Consulting's findings from its review to determine the prudency and efficiency of the SCADA and network control projects reviewed.

Based on its assessment of the Victorian DNSPs' revised regulatory proposals for SCADA and network control capex, the AER considers its estimate of $39.3 million is part of a total forecast capex that reasonably reflects the capex criteria. The AER also considers this estimate reflects the minimum adjustment necessary in order to comply with clause 6.12.3(f) of the NER. As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing SCADA and network control capex applied here, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles. Table 8.33 sets out the AER's final decision on SCADA and network control capex for Victorian DNSPs in the forthcoming regulatory period.

Table 8.33 AER final decision on SCADA and network control capex - direct costs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	2.0	2.0	2.3	2.3	2.3	10.8
Powercor	3.7	3.4	3.7	3.3	3.2	17.2
JEN	0.6	0.8	1.0	0.3	0.0	2.8
SP AusNet	1.0	1.0	1.0	1.0	1.0	4.8
United Energy	0.0	0.5	3.2	0.0	0.0	3.7

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level exclude the AER's final decision on margins, overheads and real cost increases.

8.7.7 Non-network IT and non-network other

Non-network IT

8.7.7.1 AER approach to assessment

In the draft decision, the AER's assessment was assisted by Nuttall Consulting. The AER was not satisfied that a number of the proposed non-network IT projects reasonably reflected the capex criteria. Where a DNSPs' proposed non-network IT capex did not reasonably reflect the capex criteria, the AER substituted its own forecasts.

In support of their revised regulatory proposals, the Victorian DNSPs submitted additional information explaining and justifying the need for additional non-network IT capex. The AER considered the information provided and was informed by Nuttall Consulting's report to the AER.

The AER has reviewed the revised regulatory proposals in a similar manner to the approach taken in the draft decision to arrive at its final decision. The AER's final decision accepted the revised capex forecasts of each Victorian DNSP, largely on the basis that the individual projects proposed by the Victorian DNSPs appeared to be prudent and efficient.

8.7.7.2 Summary of revised regulatory proposals

The AER's draft decision on non-network IT was not accepted by any of the Victorian DNSPs. The Victorian DNSPs submitted to restate amounts as per their initial regulatory proposals, as set out in table 8.34.

Table 8.34 Victorian DNSPs' non-network IT capex - direct costs ($'m, 2010)

	Initial proposal	AER draft decision	Revised regulatory proposal
CitiPower	44.9	24.2	43.4
Powercor	104.7	59.1	106.4
JEN	58.8	47.3	59.6
SP AusNet	143.0	72.0	143.0
United Energy	98.5	75.6	110.9
Total	**449.9**	**278.2**	**463.3**

The Victorian DNSPs did not agree with Nuttall Consulting's comments on the agility of their IT systems and the approach used to determine the allowance for non-network IT. Some of the Victorian DNSPs' criticisms included that Nuttall Consulting had not considered both applications and IT infrastructure in sufficient detail and the adjustment to the allowance was subjective.

In their revised regulatory proposals, the Victorian DNSPs have provided further information for their proposed non-network IT capex projects. The Victorian DNSPs considered that the further information should justify their expenditure in the forthcoming regulatory control period.

8.7.7.3 Summary of AER assessment and conclusions

The AER has had regard to Nuttall Consulting's report on non-network IT projects and has taken into account Nuttall Consulting's findings to determine the prudency and efficiency of the non-network IT projects reviewed.

This assessment is consistent with the capex criteria and the AER's approach to assessing non-network IT is outlined in appendix P. The following factors are particularly relevant to this analysis:

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals
- capex factor (2) – taking into account the submissions received on each Victorian DNSP's regulatory proposals
- capex factor (3) – whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting
- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (5) – where the AER has taken into account the actual and expected capex of the Victorian DNSPs during any preceding regulatory period.

Based on the assessment of non-network IT projects and methodologies used to determine each DNSP's non-network IT capex forecast, the AER considers that the individual proposed projects appeared prudent and efficient. The AER has accepted that each Victorian DNSP's revised regulatory proposal has justified that its forecast of non-network IT expenditure reasonably reflects the efficient costs of achieving the capex objectives, specifically, to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

As noted in the AER's draft decision, there was no evidence of ‘double counting’ of proposed non-network IT capex, and the IT capex amounts in the AER’s separate AMI determination.[75]

The AER considers that the Victorian DNSPs' revised regulatory proposal for non-network IT capex of $463.3 million, is part of a total forecast capex that reasonably reflects the capex criteria, specifically, to meet the expected demand for standard control services. In coming to this assessment, the AER has particularly taken into account the relevant capex factors, in particular capex factors (1), (2), (3) and (5). As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing non-network IT capex applied here, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles.

75 AER, *Draft decision*, p. 423.

Table 8.35 AER final decision on non-network IT capex - direct costs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	8.4	7.5	7.4	11.2	8.8	43.4
Powercor	22.4	19.2	17.5	26.3	21.0	106.4
JEN	17.2	17.6	14.1	5.3	5.4	59.6
SP AusNet	31.9	37.1	27.1	30.2	16.7	143.0
United Energy	23.5	36.5	27.6	16.0	7.2	110.9

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level exclude the AER's final decision on margins, overheads and real cost increases.

Non-network other

8.7.7.4 AER approach to assessment

In the draft decision, the AER's assessment was assisted by Nuttall Consulting. The AER accepted the capex proposals by CitiPower and United Energy. The AER considered Powercor, JEN and SP AusNet's proposed non-network other projects did not reasonably reflect the capex criteria, and the AER substituted its own forecasts.

Powercor, JEN, SP AusNet and United Energy additional information in their revised proposals to address the AER's concerns as described in its draft decision. The AER considered the information provided by the DNSPs and was informed by Nuttall Consulting's report to the AER.

The AER has reviewed the revised regulatory proposals in a similar manner to the approach taken in the draft decision to arrive at its final decision. The AER's final decision provides additional capex to the amounts approved in the draft decision.

8.7.7.5 Summary of revised regulatory proposals

The AER's draft decision on non-network other capex was not accepted by any of the Victorian DNSPs. In their responses to the AER's draft decision:

- Powercor and JEN submitted to restate amounts as per their initial regulatory proposals.[76] JEN sought re-inclusion of land purchases in non-network other capex instead of reinforcement capex on the basis of its historical accounting/reporting practices.[77] In the case of Powercor, no additional information was provided with its revised regulatory proposal, however, some

[76] Powercor, *Revised regulatory proposal*, pp. 320–321; JEN, *Revised regulatory proposal*, pp. 172–174.
[77] JEN, *Revised regulatory proposal*, pp. 172–173.

additional information on proposed capex for mobile cranes was provided in response to specific staff requests for further information.[78]

- CitiPower, SP AusNet and United Energy submitted to adjust the amounts set out in the AER's draft decision. CitiPower considered the AER should include 2009 actual data in its analysis of capex trends and forecast of future capex requirements, SP AusNet applied a scale escalator to the AER's draft decision and United Energy stated it had omitted capex for truck purchases in its initial regulatory proposal.[79]

Table 8.36 summarises the AER's draft decision and the Victorian DNSPs' revised regulatory proposals on non-network other capex.

Table 8.36 Victorian DNSPs' non-network other capex - direct costs ($'m, 2010)

	Initial proposal	AER draft decision	Revised regulatory proposal
CitiPower	16.4	16.4	14.9
Powercor	84.5	40.0	84.6
JEN	41.7	16.8	55.2
SP AusNet	34.7	18.2	19.0
United Energy	13.1	13.2	20.9
Total	**190.4**	**104.6**	**194.6**

In their revised regulatory proposals, the Powercor, JEN, SP AusNet and United Energy have provided further information for projects. The Victorian DNSPs considered that the further information should justify their expenditure in the forthcoming regulatory control period.

8.7.7.6 Summary of AER assessment and conclusions

The AER incorporated 2009 data in its assessment of non-network other capex.

The AER considered Nuttall Consulting's assessment of JEN and SP AusNet's proposed non-network other projects and methodologies used to derive the non-network other expenditure. The AER considers that a number of the proposed projects were not justified and therefore should not be included in the non-network other capex.

This assessment is consistent with the capex criteria and the AER approach to assessing non-network other outlined in appendix P. The following factors are particularly relevant to this analysis:

[78] Powercor, *Revised regulatory proposal*, pp. 320–321; Powercor, *Response to information requested 17 August 2010*, 26 August 2010; Powercor, *Response to information requested 17 August 2010*, 13 September 2010.

[79] SP AusNet, *Revised regulatory proposal*, pp. 153–154; United Energy, *Revised regulatory proposal*, p. 155; United Energy, *Response to information requested 9 September 2010*, 17 September 2010.

- capex factor (1) – taking into account the information in each Victorian DNSP's regulatory proposals
- capex factor (2) – taking into account the submissions received on each Victorian DNSP's regulatory proposals
- capex factor (3) – whereby the AER has undertaken analysis and has taken into account analysis undertaken by Nuttall Consulting
- capex factor (4) – assessing whether the proposed capex is consistent with what would be incurred by an efficient DNSP
- capex factor (5) – where the AER has taken into account the actual and expected capex of the Victorian DNSPs during any preceding regulatory period.

In determining an alternative forecast of non-network other capex the AER retains the view that historical expenditure needs to be taken into account when preparing a forecast.

Based on its assessment of the Victorian DNSPs' revised regulatory proposals for non-network other capex, the AER considers that its estimate of $157.7 million is part of a total forecast capex that reasonably reflects the capex criteria. The AER also considers that this estimate reflects the minimum adjustment necessary in order to comply with clause 6.12.3(f) of the NER. As discussed in section 8.6.1 of this chapter, the AER considers that the approach to assessing non-network other capex applied here, will or is likely to contribute to the NEO and takes into account the revenue and pricing principles. Table 8.37 sets out the AER's final decision on non-network other capex for Victorian DNSPs in the forthcoming regulatory period.

Table 8.37 AER final decision on non-network other capex - direct costs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	2.9	3.2	2.9	3.0	3.0	14.9
Powercor	14.6	15.6	14.7	14.9	14.7	74.5
JEN	3.4	16.1	3.4	3.5	4.0	30.5
SP AusNet	4.1	4.1	4.1	4.1	4.1	20.7
United Energy	8.0	3.5	1.8	2.0	1.8	17.0

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level exclude the AER's final decision on margins, overheads and real cost increases.

8.8 AER conclusion

For the reasons discussed in this chapter, the AER is not satisfied that the total of each of the Victorian DNSP's proposed forecast capex reasonably reflects the capex criteria in accordance with clause 6.5.7(c) of the NER. Accordingly, under clauses 6.12.1(3) and 6.5.7(d), the AER has in this chapter, set out its reasons for, and its estimate of, the required forecast capex for each Victorian DNSP for the forthcoming regulatory control period which it is satisfied reasonably reflects the capex criteria. The AER's final decision conclusion on capex allowances (on a fully absorbed basis) for the Victorian DNSPs is summarised in tables 8.38 to 8.42 below.

In accordance with clause 6.12.3 of the NER, the AER's estimate of the total required capex for the Victorian DNSPs is set out in the individual distribution determinations for each DNSP.

Since the publication of the AER’s draft decision, the Victorian Government has amended the Line Clearance regulations which relate to vegetation management of Victorian DNSPs' assets. Obligations for Victorian DNSPs to achieve targets for safety related matters recorded in an ESMS have also been introduced. The AER intends to monitor the Victorian DNSPs’ costs of undertaking this program. Chapter 21 sets out the details and process, on how the AER intends to monitor the output and outcomes of this program.

Table 8.38 AER conclusion on CitiPower capital expenditure 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	53.9	50.4	63.2	50.7	49.4	267.6
Gross demand connections	54.2	56.0	56.7	58.9	61.0	286.8
Reliability and quality maintained	26.3	29.8	31.4	35.7	39.8	163.1
Environment, safety and legal obligations	6.3	6.7	6.6	7.3	7.6	34.5
SCADA & network control	2.5	2.5	2.9	3.0	3.0	13.9
Non-network general - IT	8.5	8.3	8.3	12.8	10.2	48.0
Non-network general - other	2.9	3.5	3.3	3.4	3.4	16.5
Total gross capex	**154.6**	**157.1**	**172.4**	**171.8**	**174.4**	**830.3**
Less customer contributions	11.1	12.4	12.5	13.1	13.8	62.9
Total net capex	**143.6**	**144.7**	**159.9**	**158.7**	**160.7**	**767.5**

Note: Capex in this table includes the AER's final decision on margins, overheads and real cost increases.

Table 8.39 AER conclusion on Powercor capital expenditure 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	50.3	51.7	57.2	56.0	61.7	276.9
Gross demand connections	129.8	131.5	133.9	137.4	139.5	672.2
Reliability and quality maintained	32.7	34.1	35.3	36.7	38.2	177.1
Environment, safety and legal obligations	43.4	45.1	46.3	47.7	48.8	231.3
SCADA & network control	4.3	4.2	4.5	4.1	4.1	21.2
Non-network general - IT	22.6	20.1	18.4	28.4	22.9	112.3
Non-network general - other	14.6	16.0	15.1	15.5	15.3	76.5
Total gross capex	**297.7**	**302.7**	**310.8**	**325.8**	**330.4**	**1567.4**
Less customer contributions	47.6	48.3	48.9	49.3	49.6	243.7
Total net capex	**250.1**	**254.4**	**261.9**	**276.5**	**280.7**	**1323.7**

Note: Capex in this table includes the AER's final decision on margins, overheads and real cost increases.

Table 8.40 AER conclusion on JEN capital expenditure 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	13.2	10.2	23.0	33.1	19.0	98.4
Gross demand connections	23.7	23.7	28.9	31.2	34.8	142.3
Reliability and quality maintained	8.7	9.0	9.7	11.8	13.6	52.8
Environment, safety and legal obligations	16.9	17.3	15.3	15.6	15.6	80.6
SCADA & network control	0.6	0.9	1.1	0.3	0.0	2.9
Non-network general - IT	18.1	18.7	15.2	5.9	6.0	64.0
Non-network general - other	3.9	16.9	3.7	3.7	4.2	32.4
Total gross capex	**85.1**	**96.7**	**96.8**	**101.6**	**93.2**	**473.4**
Less customer contributions	7.3	7.3	8.3	8.0	8.7	39.5
Total net capex	**77.8**	**89.4**	**88.5**	**93.6**	**84.6**	**433.9**

Note: Capex in this table includes the AER's final decision on margins, overheads and real cost increases.

Table 8.41 AER conclusion on SP AusNet capital expenditure 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	70.4	71.8	88.5	76.3	82.3	389.3
Gross demand connections	106.0	103.0	97.7	94.6	95.0	496.3
Reliability and quality maintained	38.1	39.7	38.6	42.1	43.4	202.0
Environment, safety and legal obligations	40.4	40.1	47.4	45.5	47.4	220.8
SCADA & network control	1.0	1.0	1.0	1.0	1.0	5.0
Non-network general - IT	32.1	37.8	27.9	31.6	17.7	147.1
Non-network general - other	4.1	4.2	4.2	4.2	4.2	20.8
Total gross capex	**292.1**	**297.5**	**305.3**	**295.3**	**291.0**	**1481.2**
Less customer contributions	14.0	13.6	12.7	11.8	12.2	64.2
Total net capex	**278.1**	**283.9**	**292.6**	**283.5**	**278.9**	**1416.9**

Note: Capex in this table includes the AER's final decision on margins, overheads and real cost increases.

Table 8.42 AER conclusion on United Energy capital expenditure 2011–15 ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Reinforcement	37.1	39.2	28.3	32.7	43.6	181.0
Gross demand connections	52.9	51.4	49.7	48.8	47.0	249.7
Reliability and quality maintained	26.3	21.2	20.0	21.3	22.3	111.0
Environment, safety and legal obligations	45.3	46.1	41.5	40.4	40.1	213.4
SCADA & network control	0.0	0.5	3.2	0.0	0.0	3.7
Non-network general - IT	23.5	36.5	27.6	16.0	7.2	110.9
Non-network general - other	8.0	3.5	1.8	2.0	1.8	17.0
Total gross capex	**193.1**	**198.4**	**171.9**	**161.3**	**162.0**	**886.8**
Less customer contributions	27.7	27.1	26.5	26.8	26.0	134.0
Total net capex	**165.4**	**171.3**	**145.4**	**134.6**	**136.0**	**752.8**

Note: Capex in this table includes the AER's final decision on margins, overheads and real cost increases.

9 Opening asset base

This chapter sets out the method used by the AER to determine the closing regulatory asset base (RAB) for the Victorian distribution network service providers (DNSPs) for the 2006–10 regulatory period. The closing RAB becomes the opening RAB for the 2011–15 regulatory control period and is used to calculate the return on, and return of, capital building block components.

This chapter details the AER's assessment of the Victorian DNSPs' revised regulatory proposals, including:

- summarising the regulatory requirements regarding RAB
- summarising the AER's draft decision, the DNSPs' revised proposals and stakeholder comments
- outlining the AER's detailed considerations on the following matters:
  - data reconciliation issues
  - adjustments arising from 2005 expenditure estimates
  - inflation rate for the RAB roll forward
  - related party margins
  - decision to apply actual or forecast depreciation
- the AER's overall conclusions and RAB values for each DNSP.

9.1 Regulatory requirements

Clause 6.5.1 of the National Electricity Rules (NER) outlines the approach to be used to determine the opening RAB for a distribution determination.

Clause 6.5.1 also provides that the AER must publish an asset base roll forward model (RFM) which sets out the method for determining the roll forward of the RAB. Prior to the commencement of initial regulatory proposal, the AER confirmed and communicated with Victorian DNSPs that its published RAB roll forward model was unlikely to be fit for purpose due to Victorian specific modelling issues, requiring the submission of an alternative model.[1]

Clause S6.2.1(c)(1) provides that Victorian DNSPs' RABs for the first year of the 2011–15 regulatory control period must be determined by rolling forward the RAB values ($ real 2004, as at 1 January 2006) for each DNSP as follows:

- CitiPower—990.9 million
- Powercor—1 626.5 million

1 AER, *Vic Draft Decision*, June 2010, p. 441.

- Jemena Electricity Networks (Victoria) (JEN)—578.4 million
- SP AusNet—1 307.2 million
- United Energy Distribution (United Energy)—1 220.3 million.

Clause S6.2.1(c)(2) provides that these values are to be adjusted to allow for the difference between estimated capex and actual capex in the 2001–05 regulatory period. This adjustment must also remove any benefit or penalty associated with any such difference.

Clause S6.2.1(c)(3) states that

> …the AER must take into account the derivation of the values in the above table [schedule] from past regulatory decisions and the consequent fact that they relate only to the RAB identified in those decisions from past regulatory decisions

Clause S6.2.1(e) contains detailed provisions on how these values are further adjusted to roll forward and calculate the RAB at the beginning of the first year of the 2011–15 regulatory control period. Clause 6.5.1(e)(3) requires that the roll forward of the RAB from the immediately preceding regulatory control period to the beginning of the first regulatory year of the forthcoming regulatory control period include an adjustment for actual inflation, consistent with the method used for the indexation of the control mechanism (or control mechanisms) for standard control services during the preceding regulatory control period.

Clause S6.1.3(10) requires Victorian DNSPs to provide a completed RFM with their regulatory proposals.

Clause 6.3.2(a)(2) requires that a building block determination specify, among other things, appropriate methods for the indexation of the RAB.

Clause 6.12.1(18) requires the AER to determine whether the depreciation for establishing the opening RAB for the following regulatory control period (that is, as at 1 January 2016), is to be based on actual or forecast capital expenditure.

9.2 AER draft decision

In its draft decision the AER identified the following issues in relation to the Victorian DNSPs' RAB roll forward models:

- reconciliation of data inputs
- adjustments arising from 2005 expenditure estimates
- inflation methodology for the RAB forward model
- financing cost for JEN's capex overspend
- related party profit margin adjustment

- decision to apply actual or forecast depreciation.

The rolled-forward values for Victorian DNSPs' opening RAB as at 1 January 2011 in the draft decision are set out in table 9.1.

Table 9.1 AER draft decision on Victorian DNSPs' opening RAB ($’m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 176.8	1 194.1	1 197.6	1 206.5	1 233.5
Net capex	93.6	79.1	84.6	97.5	124.7
Depreciation	–76.3	–75.7	–75.6	–70.5	–72.0
Compound return on 2005 capex difference					0.4
Closing RAB	1 194.1	1 197.6	1 206.5	1 233.5	1 286.5
Difference from proposed RAB					–4.5
Powercor					
Opening RAB	1 916.8	1 978.7	2 034.4	2 093.0	2 136.2
Net capex	182.0	176.5	181.0	168.2	199.1
Depreciation	–120.1	–120.9	–122.4	–124.9	–126.1
Compound return on 2005 capex difference					–4.3
Closing RAB	1 978.7	2 034.4	2 093.0	2 136.2	2 204.9
Difference from proposed RAB					–11.7
JEN					
Opening RAB	653.4	673.9	695.0	691.1	708.3
Net capex	63.2	65.5	41.2	63.6	91.7
Depreciation	–42.7	–44.3	–45.1	–46.3	–46.8
Compound return on 2005 capex difference					–10.9
Closing RAB	673.9	695.0	691.1	708.3	742.2
Difference from proposed RAB					–13.4
SP AusNet					
Opening RAB	1 585.7	1 631.0	1 676.0	1 775.8	1 935.8
Net capex	129.3	137.6	198.2	263.8	256.1
Depreciation	–84.0	–92.5	–98.5	–103.7	–109.2
Compound return on 2005 capex difference					11.5
Closing RAB	1 631.0	1 676.0	1 775.8	1 935.8	2 094.2
Difference from proposed RAB					–13.1
United Energy					
Opening RAB	1388.6	1381.5	1359.0	1334.3	1365.1
Net capex	97.7	83.9	85.4	124.2	124.9
Depreciation	–104.8	–106.4	–110.1	–93.4	–82.6
Compound return on 2005 capex difference					–19.7
Closing RAB	1 381.5	1 359.0	1 334.3	1 365.1	1 387.7
Difference from proposed RAB					–19.8

Source: AER, Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015, June 2010, p. 455.

9.3 Summary of Victorian DNSP revised regulatory proposals

Victorian DNSPs' revised RAB roll forward calculations for the 2006–10 regulatory period are summarised at table 9.2.

Table 9.2 Victorian DNSP revised RAB roll forward for the 2006–10 regulatory period ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 177.1	1 194.3	1 197.8	1 206.8	1 233.4
Net capex	93.6	79.1	84.6	97.1	125.8
Depreciation	–76.3	–75.7	–75.6	–70.5	–72.0
Compound return on 2005 capex difference					0.5
Closing RAB	1 194.3	1 197.8	1 206.7	1 233.4	1 287.6
Powercor					
Opening RAB	1 918.3	1 980.1	2 035.8	2 094.4	2 137.5
Net capex	182.0	176.5	181.0	168.0	207.2
Depreciation	–120.1	–120.9	–122.4	–124.9	–126.1
Compound return on 2005 capex difference					–3.9
Closing RAB	1 980.1	2 035.8	2 094.4	2 137.5	2 214.7
JEN					
Opening RAB	654.4	676.1	698.1	695.1	722.1
Net capex	64.4	66.3	42.2	73.3	91.8
Depreciation	–42.7	–44.3	–45.1	–46.3	–46.8
Compound return on 2005 capex difference					–10.6
Additional 6 months CPI escalation					9.7
Closing RAB	676.1	698.1	695.1	722.1	766.2
SP AusNet					
Opening RAB	1 583.2	1 634.3	1 680.4	1 782.0	1 920.7
Net capex	135.0	138.7	200.1	242.5	256.1
Depreciation	–84.0	–92.5	–98.5	–103.7	–109.2
Compound return on 2005 capex difference					11.9
Closing RAB	1 634.3	1 680.4	1 782.0	1 920.7	2 079.6
United Energy					
Opening RAB	1 388.6	1 381.5	1 359.0	1 334.3	1 358.6
Net capex	97.7	83.9	85.4	117.7	124.9
Depreciation	–104.8	–106.4	–110.1	–93.4	–82.6
Compound return on 2005 capex difference					–19.7
Closing RAB	1 381.5	1 359.0	1 334.3	1 358.6	1 381.2

Source: Victorian DNSPs' revised regulatory proposals, RAB roll forward models, July 2010.

9.4 Summary of submissions

The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria (the Minister) submitted that in considering the related party margin adjustment for the RAB roll forward, the AER:

- must do so in a manner that will or is likely to contribute to the National Electricity Objective (NEO)
- should refer to the revenue and pricing principles of the National Electricity Law (NEL) in defining 'capital expenditure'
- adopt an interpretation of the NEL that will best achieve its purpose or object with such an interpretation to be preferred over another interpretation.[2]

The Minister also submitted that the Victorian Government supported the continuing use of depreciation based on forecast capital expenditure (regulatory depreciation) as this approach is more suited to the specific circumstances that apply in Victoria. In addition, the Minister submitted that the appropriate process to determine whether actual depreciation or regulatory depreciation should be consistently applied in all determinations is through a rule change process.[3] The Victorian Department of Primary Industry (DPI) also made a similar submission reiterating the Minister's views.[4]

EnergyAustralia submitted that the logic of applying actual depreciation for 2016–20 is contrary to the premise of the AER’s decision to reject forecast requirements on the basis of underspends in the previous period, and that the AER has created high incentives for the business to underspend its forecasts but has penalised the business for making decisions in accordance with these incentive arrangements in the previous period.[5]

JEN submitted that a service provider entering into an outsourcing arrangement with a related entity is not, in itself, sufficient to conclude that transfer pricing had actually occurred between related parties. JEN disagreed with the Minister that in not making adjustments to the roll forward calculations with respect to related party margins the AER has provided an incentive to the Victorian DNSPs in relation to capitalisation policies and contract fees. JEN also disagreed with the Minister on the interpretation of the NER. JEN contended that the Tribunal's AMI decision did not support Minister’s submission that margins paid to third parties were not capital expenditure incurred in providing distribution services.[6]

2 Minister for Energy and Resources, *Submission to the AER*, 20 August 2010, pp. 1–4.
3 ibid., p. 9.
4 Victorian Department of Primary Industry, *Further submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–15*, 12 October 2010, pp. 1–2.
5 Energy Australia, *Energy Australia’s submission on AER’s draft regulatory determination for Victorian distributors*, 19 August 2010, pp. 2–3.
6 JEN, *Jemena 2011–15 regulatory proposal: Response to stakeholder submissions - attachment 5,* 24 September 2010, pp. 1–6.

9.5 Issues and AER considerations

9.5.1 Data reconciliation

9.5.1.1 AER draft decision

The Essential Services Commission of Victoria's (ESCV) estimated capex values for 2005 were disaggregated for all asset categories except for transmission and distribution system assets. To deal with this information gap, the AER applied the proportion of actual 2006 capex for these two asset categories for each Victorian DNSP to determine the 2005 estimated expenditure for these categories.

The AER identified data discrepancies between Victorian DNSPs' RAB roll forward models, RIN templates and regulatory accounting statements. Where discrepancies were present and inadequately explained, the AER used data from regulatory accounting statements, as they are audited and prepared in accordance with the ESCV's *Regulatory Information Requirements Guideline No. 3 (Regulatory Accounting Guideline)*. As a result, the AER made minor amendments to some RFM calculations.

9.5.1.2 Victorian DNSP revised regulatory proposals

SP AusNet contended that the AER's draft decision applied incorrect capex numbers for 2005 to 2008. SP AusNet also updated its roll forward model for actual 2009 capex.[7]

The other Victorian DNSPs did not raise an issue with the AER's draft decision regarding data reconciliation.

9.5.1.3 Issues and AER considerations

Further to the draft decision, the AER identified that all Victorian DNSPs, to varying degrees and for various years, presented data which did not reconcile to their regulatory accounting statements, RIN templates and RFMs. All discrepancies have been explained by the Victorian DNSPs which were either accepted by the AER or resulted in minor adjustments to the RAB calculations.

SP AusNet

The issue raised by SP AusNet regarding capex data for 2005 to 2008 related to the treatment of provisions. Although SP AusNet provided some information regarding provisions prior to the draft decision, the AER was unable to fully reconcile this information to the 2005–08 regulatory accounting statements.

In addition to the information contained in SP AusNet's revised regulatory proposal, the AER sought further information regarding movement in provisions for the period 2005–09 to be included in the capex.[8] In reviewing this further information the AER noted that some of SP AusNet's provision adjustments did not appear to be consistent with adjustments disclosed in SP AusNet's regulatory accounting statements.[9] The

7 SP AusNet, *Electricity Distribution Price Review*, *Revised Regulatory Proposal*, July 2010, p. 295.

8 AER, *Information request to SP AusNet on provisions 2005-2009*, 13 August 2010.

9 These provision adjustments related to 'current provision - uninsured losses'; 'current liabilities - provision - customer rebates'; 'non-current assets - superannuation'.

AER has reviewed SP AusNet's further response on this issue and the proposed adjustments as discussed in chapter 13.[10] These changes have been included in the calculation of SP AusNet's RAB roll forward.

The AER also identified that RFM disposal values submitted by SP AusNet were sourced from the written down value of disposals. However, the AER does not consider it appropriate for SP AusNet to change the method of valuation from that set by the ESCV when rolling forward asset values over the current regulatory control period. Consequently the AER has instead used asset sale proceeds as the value of disposals (that is, the disposal data from regulatory accounting statements) consistent with the approach used by the ESCV in its 2006 Electricity Distribution Price Review (2006 EDPR).

United Energy

The AER identified that input data in United Energy's RAB roll forward model did not reflect actual information for 2009 in accordance with regulatory accounting statements and RIN templates.

The AER raised these inconsistencies with United Energy, which provided an updated RFM to include actual data for 2009. The updated RFM addressed these inconsistencies, and on the basis, the AER accepted it.[11]

9.5.1.4 AER conclusion

In the calculation of RAB roll forward the AER has in general applied regulatory accounting statements as they are audited and prepared in accordance with the ESCV's *Regulatory Accounting Guideline*. As a result, the AER has made minor amendments to some RFM calculations.

9.5.2 Adjustments arising from 2005 expenditure estimates

9.5.2.1 AER draft decision

The AER made adjustments to the opening RAB for the Victorian DNSPs for the difference between the estimated and actual capital expenditure for 2005, given that these calculations were affected by the incorrect disaggregation of 2005 data for estimated capex and regulatory depreciation. The AER also removed any penalty (reward) which reflected the additional (unearned) return on capital over the 2006–10 regulatory period associated with the value of the overestimate (underestimate) for 2005. This adjustment was required by clause S6.2.1(e)(6) of the NER.

These amounts were added to or deducted from the 1 January 2011 opening RAB for each Victorian DNSP for the 2011–15 regulatory control period as shown in table 9.3.

[10] SP AusNet, *SP management fee, provisions and other issues*, 8 September 2010.
[11] United Energy, *Asset modelling questions*, 20 August 2010.

Table 9.3 AER draft decision on forecast and actual net capex adjustments for 2005 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Estimate	83.2	173.3	83.5	160.9	142.9
Actual	84.4	160.2	50.7	195.7	83.6
Difference	1.1	–13.0	–32.8	34.7	–59.3
Penalty/reward	0.4	–4.3	–10.9	11.5	–19.7

Source: AER, *Vic Draft Decision*, June 2010, p. 447.

9.5.2.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs' proposed adjustments to the opening RAB to correct for the difference between the estimated and actual capital expenditure for 2005, and subsequent adjustments to the 2010 closing RAB (all converted into 2010 dollars) are set out in table 9.4. The calculated penalty (reward) reflects the additional (unearned) return on capital associated with the value of the overestimate (underestimate) for 2005.

Table 9.4 Victorian DNSP proposed forecast and actual net capex adjustments for 2005 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Estimated	83.2	173.3	83.5	160.9	142.9
Actual	84.6	161.7	51.7	193.2	83.6
Difference	1.4	–11.6	–31.8	32.2	–59.3
Penalty/reward	0.5	–3.9	–10.6	11.9	–19.7

Source: Victorian DNSPs' revised RFMs.

CitiPower and Powercor 2005 disposals

CitiPower and Powercor accepted the draft decision in relation to the opening RAB, except for the AER's adjustment to the value of 2005 disposals.[12]

CitiPower and Powercor stated that clause S6.2.1(e)(6) does not empower the AER to make adjustments for disposals occurring prior to the previous regulatory period, for example, in 2005.[13]

SP AusNet financing cost for the 2005 capex overspend

SP AusNet did not accept the AER's draft decision to not compensate it for forgone financing costs incurred over the year 2005 from the capital overspend. SP AusNet contended that under the ESCV's approach, the opening and closing RAB is averaged

12 CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, pp.333–34; Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, pp. 324–26.

13 CitiPower, *Revised regulatory proposal*, pp. 333–34; Powercor, *Revised regulatory proposal*, pp. 324–26.

and return on capital is earned on the average RAB thus compensating the business for return on capital payments on the capex spent in the year (which is 2005 for the issue in question). SP AusNet stated that the PTRM assumes implicitly that all capex occurs in the middle of each year, and so the amount of capex rolled into the RAB at the end of each year includes the cost of financing that capex for six months. SP AusNet stated that the AER's calculation in the draft decision did not account for this. SP AusNet argued that the AER has made a material error in not providing for the financing costs incurred during the 2005 year.[14]

9.5.2.3 Issues and AER considerations

CitiPower and Powercor 2005 disposal

The AER disagrees with CitiPower's and Powercor's suggestion that the AER is unable to make adjustments to the 2011 opening RAB for disposals occurring prior to the previous regulatory period (for example in 2005).

Clause S6.2.1(c)(3) expressly provides that the AER must take into account the derivation of the RAB values specified at clause S6.2.1(c)(1). In doing so, the AER has identified that the RAB value of $990.9 million (real 2006) for CitiPower and $1 626.5 million (real 2006) for Powercor, reflects an amount of zero of estimated disposals for both DNSPs in 2005. In the AER's view, to not adjust for the difference between actual and estimated disposals in 2005 is inconsistent with it similarly adjusting for differences between actual and estimated capex in that same year, as required by clause S6.2.1(c)(2).

Further, it is, in the AER's view, standard practice in modelling DNSPs' asset bases to deduct the value of disposals (and capital contributions) from capital expenditure when it is added to the RAB.

The AER considers that, where the same provisions appear in chapter 6 and chapter 6A, the Australian Energy Market Commission's (AEMC's) chapter 6A rule determination may appropriately inform the interpretation of the equivalent provisions in chapter 6. In drafting the Chapter 6A provisions for the RAB roll forward, the AEMC stated:

> where information on actual capital expenditure is unavailable at the time of the regulatory determination (typically the last year of the regulatory period), an estimate of expenditure should be used, and there should be a subsequent adjustment in undertaking the roll-forward in the subsequent regulatory period. The removal of any benefit or penalty associated with differences between estimated and actual values is intended to remove any adverse incentives in relation to the estimation process.[15]

While clause S6.2.1(c)(2) does not explicitly account for disposals or capital contributions, to omit these influences on the actual and estimated capex in the required calculation of penalties and rewards would be inconsistent with the intention of the AEMC.

14 SP AusNet, *Revised regulatory proposal*, pp. 296–97.

15 AEMC, *Review of the electricity transmission revenue and pricing rules, footnote 71*, February 2006, p. 58.

Hence the AER has adjusted for the 2005 estimated disposals (and capital contributions) from the gross capex to derive the net 2005 estimated capex, in deriving the opening RAB for the 2011–15 regulatory control period.

SP AusNet financing cost for the 2005 capex overspend

The AER acknowledges that the methodology it applied to calculate the return on capital building block differs from that of the ESCV, due to different cash flow timing assumptions.

The AER consulted the other Victorian DNSPs on SP AusNet's arguments in relation to the removal of the return on capital associated with estimated capex in 2005.[16] In response, JEN considered that financing costs for 2005 expenditures should not be included because it:

> …did not actually get any 2005 financing cost benefit or penalty associated with its 2005 capex underspend in the 2005 EDPR. Rather, the ESC only gave a financing cost benefit on this underspend in its allowed building blocks revenue for the 2006 to 2010 years. In other words, if the ESC had correctly forecast 2005 capex, then the only change would be a reduction to JEN's allowed building blocks revenue for 2006 to 2010.[17]

The AER agrees with JEN that the 2005 EDPR is the only relevant decision for the purposes of calculating a benefit or penalty under clause S6.2.1(c)(2) because this decision established the opening 2006 RAB value. That is, any penalties or rewards arising from estimated expenditures in 2005 only could have formed part of the ESCV's calculation of building blocks for 2006 to 2010, regardless of the cash flow timing assumptions used. No response was received from other DNSPs.

9.5.2.4 AER conclusion

Based on the considerations above, the AER has adjusted the opening RAB for the Victorian DNSPs, under clause S6.2.1(c)(2), for the difference between the estimated and actual capital expenditure (including disposals) for the calendar year 2005 and removed any benefits or penalties in the form of additional or forgone return on capital. Accordingly, these amounts have been added to or deducted from the 1 January 2011 opening RAB for each Victorian DNSP for the 2011–15 regulatory control period as shown in table 9.5.

[16] AER, *Asset modelling questions to CitiPower, Powercor, JEN and United Energy*, 11 August 2010.

[17] JEN, *JEN's response to asset modelling questions 13 August 2010*, 13 August 2010, pp. 2–3.

Table 9.5 AER conclusion on forecast and actual net capex adjustments for 2005 ($'m, 2010)

	CitiPower	Powercor	JEN	SP AusNet	United Energy
Estimate	83.2	173.3	83.5	160.9	142.9
Actual	84.4	160.2	51.7	192.8	83.6
Difference	1.1	–13.0	–31.8	31.9	–59.3
Penalty/reward	0.4	–4.3	–10.6	10.6	–19.7

Source: AER's RAB roll forward models.

9.5.3 Inflation rate for RAB roll forward

9.5.3.1 AER draft decision

SP AusNet applied a March to September annual CPI to adjust the RAB for actual inflation for 2004 data values. JEN applied a September to September annual CPI throughout its modelling, with a further forecast six month inflation to convert asset values from July 2010 to December 2010 dollar terms.

The AER examined the ESCV's models and confirmed that costs prior to 2004 were escalated by the annual CPI as per the control mechanism, which used a September CPI value. The AER considered that the inflation adjustments of the RAB proposed by JEN and SP AusNet were incorrect because the annual CPI adjustment was approximated by September inflation which will be applied to the asset values and PTRM.

The AER considered it appropriate to maintain consistency with the ESCV's treatment of CPI between building block revenue requirements, asset values and the CPI-X price control throughout the 2011–15 regulatory control period by continuing to apply the ESCV's indexation methodology for the current control mechanism and in the subsequent roll forward calculations.

Accordingly, the AER removed the additional CPI applied by SP AusNet (for 2004 data) and JEN (for 2010 data) as this was inconsistent with the escalation of the 2006–10 regulatory period's control mechanism.

9.5.3.2 Victorian DNSP revised regulatory proposals

JEN did not accept the AER's draft decision to disallow six months of additional escalation, to translate its 2006 opening RAB as specified in the NER, to a 31 December 2010 dollar value.[18]

JEN contended that its 2006 opening asset base value of $578.4 million is in 1 July 2004 dollar values. In JEN's view, the fact that the ESCV used September CPI values as the basis for annual escalation does not allow or support any inference about the point in the year at which the dollar values are expressed.[19]

18 JEN, *Revised regulatory proposal,* pp. 213–17.
19 ibid., p. 214.

In addition, JEN submitted that clause S6.2.1(c)(1) is unambiguous in that it expresses the 2006 opening RAB of $578.4 million in July 2004 dollars. It follows that six and a half years' CPI escalation must be applied to that value to convert it to an end of year (31 December) 2010 value that is consistent with the AER's PTRM.[20]

JEN argued that the additional half year's inflation it proposed would not create an inconsistency between inflation as applied in the roll forward and in the AER's PTRM where the annual CPI adjustment is also approximated by September inflation.[21]

SP AusNet accepted and modified its modelling in accordance with the AER's draft decision, reflecting the ESCV's inflation modelling underlying the 2006 EDPR final decision.[22]

9.5.3.3 Issues and AER considerations

In response to JEN's submission, the AER considers that the reference to '1 July 2004' in clause S6.2.1(c)(1) of the NER means that cash flows are assumed to be incurred evenly throughout the year, as approximated by a mid year value. Accordingly, the AER does not consider that the opening RAB figure specified in clause S6.2.1(c)(1) was valued as at 1 July 2004. As discussed in the draft decision, the AER has examined the ESCV's models and confirms that costs prior to 2004 were escalated by the annual CPI as per the control mechanism, which used a September CPI value. This September CPI was used to approximate middle of the year (1 July) values to maintain consistency with the lagged September CPI data used in the control mechanism.

The AER considers the inflation adjustment of the RAB proposed by JEN is incorrect because the annual CPI adjustment is also approximated by September inflation which will be applied to the PTRM. Applying an additional 6 months inflation, as proposed by JEN, creates an inconsistency between inflation as applied in the roll forward and in the AER's PTRM. To do so would over-compensate JEN by six months' inflation.

9.5.3.4 AER conclusion

The AER has removed the additional CPI applied by JEN (for 2010 data) which is inconsistent with the escalation of the 2006–10 regulatory period's control mechanism.

9.5.4 Related party margins

In chapter 6 of this final decision, the AER uses the term 'margin' to reflect any difference between a contract price and a contractor's actual direct costs. In this sense, contract margins include allowances for a contractor's corporate and other indirect costs, as well as 'profit margins'.

In the Jemena Gas Network (JGN) final decision, the AER considered the accounting standard criteria for the recognition and measurement of capital costs. The AER did not recognise some of JGN's corporate costs—specifically its Enterprise Support Function (ESF) costs—as capital expenditure, given that the ESF costs were related to

[20] ibid., pp. 213–14.
[21] ibid., pp. 215–16.
[22] SP AusNet, *Revised regulatory proposal*, p. 295.

corporate head office activities, which the accounting standard specifically excludes from being capex or of a capital nature.[23]

The AER has carefully reviewed the reported capex incurred by the Victorian DNSPs during the 2006–10 regulatory period, which includes capitalised corporate costs of the Victorian DNSPs' related party contractors. The AER considers that these capitalised corporate costs are properly of a capital nature, and meets the requirement in clause S6.2.1(e)(1) of being 'capital expenditure incurred during the previous period' for the purposes of increasing the Victorian DNSPs' RABs.

On the other hand, whether 'profit margins' paid by the Victorian DNSPs to their related parties can also meet this requirement is a different issue. This is discussed below.

9.5.4.1 AER draft decision

The Victorian DNSPs proposed to include the amount of margins and management fees to related entities as capex over the 2006–10 regulatory period. In the draft decision, the AER did not adjust the Victorian DNSPs’ roll forward calculations for these related party margins, on the basis that Chapter 6 of the NER does not provide for the AER to assess capex ex post. In particular, the AER considered the extent to which the margins paid would be characterised as inefficient capital expenditure (that is, the amount was simply above what would have been incurred in a competitive market) or whether they were so excessive as to have no relationship to the services provided by the related party or the DNSP (and therefore not simply inefficient, but not 'capital expenditure' at all).

9.5.4.2 Submissions on DNSP revised regulatory proposals

The Minister submitted that in considering the related party margin adjustment for the RAB roll forward, the AER must do so in a manner that will or is likely to contribute to the NEO. In addition, the Minister submitted that the AER should refer to the revenue and pricing principles of the NEL in defining the 'capital expenditure'. The Minister also submitted that clause 7 of Schedule 2 of the NEL mandates that the AER adopt an interpretation of the NEL that will best achieve its purpose or object with such an interpretation to be preferred over another interpretation. Pursuant to clause 41 of Schedule 2, clause 7 applies to the NER.[24]

JEN responded to the Minister's submission, contending that a service provider entering into an outsourcing arrangement with a related entity is not, in itself, sufficient to conclude that any transfer pricing had actually occurred between related parties.[25]JEN argued that an agreement between related parties is likely to constitute a more efficient outcome than providing the services in-house.[26]

JEN disagreed with the Minister that, in not making adjustments with respect to related party margins, the AER has provided an incentive for the DNSPs to artificially

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[23] AER, *Jemena Gas Networks access arrangement proposal for the NSW gas networks 1 July 2010–30 June 2015*, final decision, June 2010, pp. 53–54.

[24] Minister for Energy and Resources, *Submission to the AER*, 20 August 2010, pp. 1–4.

[25] JEN, *Jemena 2011–15 regulatory proposal: Response to stakeholder submissions - attachment 5,* 24 September 2010, pp. 1–6.

[26] ibid., p. 3.

maximise the level of expenditure that is capitalised, including through capitalisation policies and through fees that are unrelated to the costs of providing distribution services.[27]

JEN also disagreed with the Minister on the interpretation of the NER. JEN submitted that clause 7 of Schedule 2 of the NEL does not apply to the interpretation of the NER, it applies to the interpretation of the NEL and there is no ambiguity in clause S6.2.1(e)(1) of the NER such that it is necessary to look beyond the meaning of the words in that clause in order to interpret that clause and to give it meaning.[28]

JEN contended that the Australian Competition Tribunal's decision on Advanced Metering Infrastructure (AMI) did not support the Minister's submission that the capital expenditure incurred by service providers, to the extent it includes margins paid to third parties, is not capital expenditure actually incurred in providing distribution services.[29]

9.5.4.3 Issues and AER considerations

The AER agrees with the Minister that there is a perverse incentive in the RAB roll forward which is not in the long term interests of consumers. This also arguably undermines the incentive-based regulatory regime in Chapter 6. The AER noted in the draft decision that the presumption in clause S6.2.1(e)(1) that the AER will automatically recognise all capex incurred in the previous regulatory control period in the DNSPs' RAB roll forward calculations highlights a potentially serious issue with the capex incentive framework under Chapter 6 of the NER.

Section 16(1)(a) of the NEL imposes an obligation on the AER to exercise its function or power in a manner that will or is likely to contribute to the achievement of the NEO. Section 16(2) requires the AER to take into account the revenue and pricing principles (RPP) when exercising a discretion in making those parts of a distribution determination relating to direct control network services or in exercising any other AER's economic regulatory functions or power where it considers appropriate to do so. It is important to recognise that the RPP themselves cannot be relied on to exercise or create a power or discretion which the NEL or the NER does not otherwise provide the AER.

Section 7 of Schedule 2 of the NEL provides that in interpreting a provision of the NEL or the NER, the interpretation that will best achieve the purpose or object of the NEL or the NER is to be preferred to any other interpretation.[30] This, however, does not allow the AER to depart from the requirements of clause S6.2.1(e)(1) of the NER which the AER considers are clear. In this case, the AER's task is limited to determining whether the amounts proposed to be included in the RAB can be said to be "capital expenditure incurred" for the purposes of clause S6.2.1(e)(1).

In making its draft decision the AER carefully examined the nature of related party margins with respect to the recognition of 'all capital expenditure incurred' under clause S6.2.1(e)(1). In particular, the AER considered the extent to which the margins

27 ibid., pp. 3–4.
28 ibid., pp. 4–5.
29 ibid., pp. 5–6.
30 Schedule 2 of the NEL also applies to the NER by reason of section 41 of Schedule 2 of the NEL.

paid would be characterised as inefficient capital expenditure (that is, the amount was simply above what would have been incurred in a competitive market) or whether they were so excessive as to have no relationship to the distribution system and the provision of standard control services through the distribution system (and therefore not simply inefficient, but not 'capital expenditure' at all).

The AER has again reviewed the evidence before it in the form of contracts between the Victorian DNSPs and their related parties. Specifically the AER has reviewed the major contracts between the Victorian DNSPs and their related parties as discussed in chapter 6 and its appendix. The evidence does not suggest that the margins paid by the Victorian DNSPs are so excessive as to have no relationship with the distribution and the provision of standard control services through the distribution system. Further, there is also nothing to suggest that the margins paid bear no relationship to the activity of acquiring or creating capital items nor is there any suggestion that any of these margins serve purposes other than for the payment of capital.

In its review, the AER has identified that CitiPower and Powercor have network services agreements with a related party, Powercor Network Services (PNS), for 2008–10. The AER also identified that JAM has been managing JEN's network since October 2000, under a 'letter agreement'. According to JEN's RIN, there was no margin paid to JAM and reported as capex for the period 2006–09. The AER also notes that JEN and JAM have agreed to a new arrangement (referred as their asset management agreement (AMA)), which replaced the letter agreement from 1 January 2010. The AER has also reviewed related party contracts for SP AusNet and United Energy.

In reviewing each of these arrangements, the AER found that:

- the services provided under these arrangements, for which the associated costs are reported by the Victorian DNSPs as capex, is of a capital nature
- the profit margins earned by the Victorian DNSPs in these contracts were not so excessive as to have no relationship to the distribution system and the provision of standard control services through the distribution system.

Accordingly, these margins meet the requirements of being 'capital expenditure incurred' for the purposes of clause S6.2.1(e)(1) of the NER and must be rolled into the Victorian DNSPs' RABs.

As a cross check, the AER has also reviewed Victorian DNSPs' AMI applications to identify whether some of the opex margins proposed in that process are now being proposed as capex, for the purposes of the RAB roll forward. The AER concluded that there is no apparent change in the nature of expenditures between contracts for AMI and for the DNSPs' distribution services contracts.[31]

In summary, the AER considers that its task in the RAB roll forward is limited to determining whether the amounts proposed to be included in the RAB are 'capital

[31] The AER notes that there is no further breakdown of Victorian DNSPs' reported capex margins for the RAB roll forward, given that Victorian DNSPs only reported capex with and without margins according to asset categories for the RAB roll forward, therefore margins under RAB roll forward were calculated by taking the difference of the two.

expenditure incurred'. As discussed above, having reviewed the evidence before it, the AER does not consider that the margins paid by the DNSPs to their related parties have no relationship to the activity of acquiring or creating capital items or are not of a capital nature.

However, the question as to whether related party margins meet the requirement of capital expenditure incurred is separate to the issue of whether the related party margins included within the Victorian DNSPs' proposed forecast capex are efficient or prudent and ultimately, whether the AER is satisfied they reasonably reflects the capex criteria. This is discussed further in chapter 6.

The issue of symmetry between capex and opex incentives (noted in the case of capitalisation policy changes) may be addressed by extending the AER's EBSS to capex as provided for under the NER. The AER considers, however, that the capitalisation of related party margins potentially gives rise to more fundamental issues relating to the requirements of clause S6.2.1(e)(1), which may be addressed by a rule change (including to the equivalent provisions in Chapter 6A).

9.5.4.4 AER conclusion

The AER has not made adjustments to the Victorian DNSPs' roll forward calculations with respect to related party margins.

9.5.5 Decision to apply actual or forecast depreciation

9.5.5.1 AER draft decision

Clause 6.12.1(18) of the NER requires the AER to determine whether the depreciation for establishing the opening RAB for the following regulatory control period (that is, as at 1 January 2016), is to be based on actual or forecast capex (referred to here as the use of actual or forecast depreciation). The Victorian DNSPs did not address this matter in their initial regulatory proposals.

The AER considered it important to provide effective incentives for Victorian DNSPs to seek out efficiencies wherever possible in their capex programs, and that a higher powered incentive was therefore appropriate.

The AER determined that actual depreciation will be used to establish the opening RAB for the 2016–20 regulatory control period for the Victorian DNSPs.

9.5.5.2 Victorian DNSP revised regulatory proposals

SP AusNet did not accept the AER's draft decision to use actual depreciation to establish the opening RAB for the 2016–20 regulatory control period.[32]

SP AusNet submitted that the AER has proposed large reductions in its proposed IT and Non-network general capex, therefore the high power incentive regime that applies to IT and Non-network general capex effectively precludes them from spending more than the AER's allowance regardless of the capex savings that are

[32] SP AusNet, *Revised regulatory proposal*, pp. 297–98.

made elsewhere. SP AusNet also argued that deficiencies in capex allowance in the draft decision are likely to be sustained for a number of regulatory control periods.[33]

SP AusNet proposed that the incentive arrangements for its IT and Non-network general capex exclude a return of capital component and retain only the return on capital component. SP AusNet contended that whilst this approach provides weaker incentives to deliver capex savings relative to the AER's benchmark allowance, it imposes less severe penalties for capex overspending.[34]

The other Victorian DNSPs did not raise issue with the use of actual or forecast depreciation for 2016–20 regulatory control period.

9.5.5.3 Submissions on DNSP revised regulatory proposals

The Minister submitted that the Victorian Government supports the continuing use of depreciation based on forecast capital expenditure (regulatory depreciation) as this is considered to be the approach more suited to the specific circumstances that apply in Victoria, namely:

- the regulatory framework provides an incentive for DNSPs to forecast high capital expenditure
- the Victorian DNSPs generally underspend relative to forecast whereas DNSPs in other jurisdictions generally overspend relative to forecast
- the regulatory depreciation for the Victorian DNSPs is therefore generally greater than actual depreciation whereas the regulatory depreciation for DNSPs in other jurisdictions is generally less than actual depreciation
- Victorian consumers have already paid for regulatory depreciation (as one component of the building blocks revenue) and will effectively pay twice for some depreciation if the (lower) actual depreciation is rolled into the asset base
- under these circumstances, the regulatory asset base will effectively be larger if actual deprecation is rolled in rather than regulatory depreciation
- the use of regulatory depreciation rather than actual depreciation places downwards pressure on the capital expenditure forecasts—if the regulatory depreciation is too high relative to actual depreciation, the assets will be written off in the regulatory accounts much earlier than in the statutory accounts.[35]

In addition, the Minister submitted that the appropriate process to determine whether actual depreciation or regulatory depreciation should be consistently applied in all

33 ibid., p. 297.
34 ibid., pp. 297–98.
35 Minister for Energy and Resources, *Submission to the AER*, 20 August 2010, pp. 8–9.

determinations is through a rule change process.[36] DPI reiterated the Minister's view.[37]

EnergyAustralia submitted that the logic of applying actual depreciation for 2016–20 is contrary to the premise of the AER's decision to reject forecast requirements on the basis of underspends in the previous period, and the AER has created high incentives for the business to underspend its forecasts but has penalised DNSPs for making decisions in accordance with these incentive arrangements in the previous period.[38]

9.5.5.4 Issues and AER considerations

The AER does not agree with SP AusNet's claim of deficiencies for its IT and non-network general capex allowances for the 2011–15 regulatory control period. In its draft and final decisions, the AER has estimated the required total forecast capex, which includes allowances for IT and Non-network general, that it is satisfied reasonably reflects the capex criteria, taking into account of the capex factors, as discussed in Appendix P.[39] Further, as discussed in chapter 8, the AER considers that the approach it applied to assessing forecast capex will or is likely to contribute to the NEO and takes into account the RPP.

However, as noted in section 9.5.5 of the draft decision, the AER's views is that the incentive framework which applies to forecast capex under Chapter 6 is relatively weak and the general incentives on capex and opex are unbalanced, particularly under the arrangements put in place by the ESCV where depreciation does not form part of the incentive framework. Relevantly, the RPP, in part provides:

> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and
>
> (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.[40]

Taking into account the RPP, the AER is of the view that it is required to provide effective incentives or to strengthen the incentives for Victorian DNSPs to seek out efficiencies wherever possible in its capex programs. Allowing SP AusNet to exclude the return of capital component from its opening RAB for IT and non-network general capex leads to a weaker incentive to deliver capex savings and does not, in the AER's view, provide an effective incentive to seek out capex efficiencies in the context of the RAB, nor does it provide a consistent assessment framework for the RAB.

36 ibid., p. 9.
37 Victorian Department of Primary Industry, *Further submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–15*, 12 October 2010, pp. 1–2.
38 EnergyAustralia, *Submission to the AER*, 19 August 2010, pp. 2–3.
39 AER, *Vic Draft Decision*, June 2010, pp. 415–39.
40 Section 7A(3) of the NEL.

The AER acknowledges that under an actual depreciation approach, a DNSP retains a greater proportion of the gain or loss of assets with relatively short lives such as IT and non-network general capex in comparison to assets with longer lives. Whilst there may be merit in reconsidering how assets are classified for depreciation purposes, that is a matter appropriately addressed in the context of any potential amendments to the AER's PTRM and RFM and not in this final decision.

As noted in the draft decision, the use of actual depreciation is also consistent with the economic regulation of transmission network service providers under Chapter 6A of the NER and the AER's distribution determinations in New South Wales Australian Capital Territory, Queensland and South Australia.[41]

As to the Minister's concerns that the Victorian DNSPs have underspent capex relative to their forecasts, the AER is aware that this occurred during the 2001–05 regulatory period, where actual expenditure was 18 per cent below forecast. The AER notes that an efficiency carryover mechanism was applied to capex during this period, which maintained the strength of the incentives applied to capex. For the 2006–10 regulatory period, there was a slight capex overspend, estimated to be less than 1 per cent above the forecast capex allowance.

Capex underspends and the potential benefits accruing to the Victorian DNSPs appear to be at the heart of the Minister's and DPI's concerns. In this regard, the AER notes that the revealed cost approach, whereby actual expenditures provide a good indicator of efficient costs in the future, relies on an effective incentive framework.

That said, the AER does not agree with EnergyAustralia's comments on this issue as the approach used by the AER to test forecasts of capital expenditure did not rely solely on historical expenditure. The AER's approach is set out in detail in chapter 8.

In response to the Minister's and DPI's suggestion regarding a potential rule change process to determine whether actual depreciation or regulatory depreciation should be consistently applied, this is a matter for the AEMC. Clause 6.12.1(18) of the NER provides the AER with discretion on whether depreciation for establishing the RAB is to be based on actual or forecast capital expenditure. While the AER does not view consistency as an end itself, it is an underlying rationale for the establishment of national regulatory arrangements, and as noted above, its view on the desirability of the use of actual depreciation reflects that capex incentives are relatively weak if depreciation is not included in the incentive framework.

9.5.5.5 AER conclusion

The AER determines that actual depreciation will be used to establish the opening RAB for the 2016–20 regulatory control period for the Victorian DNSPs.

9.6 AER conclusion

The AER has reviewed the Victorian DNSPs' proposed opening RAB values and the cost inputs to their RFMs for the 2006–10 regulatory period and has cross checked

[41] AER, *ActewAGL distribution determination 2009–10 to 2013–14,* April 2008; AER, *New South Wales distribution determination 2009–10 to 2013–14,* April 2009; AER, *Queensland distribution determination 2010–11 to 2014–15,* May 2010; AER, *South Australian distribution determination 2010–11 to 2014–15,* May 2010.

these against their regulatory accounting statements. The AER has identified the following issues and made adjustments for them accordingly:

- reconciliation of data inputs (as noted in section 9.5.1)
- adjustments arising from 2005 expenditure estimates (9.5.2)
- inflation methodology for the RAB forward model (as noted in section 9.5.3)

In accordance with clause 6.12.1(6) of the NER, the AER has determined opening RAB values for the Victorian DNSPs as at 1 January 2011. In determining these values, the AER considers it has done so in a manner which will or is likely to contribute to the achievement of the NEO. The AER has also had regard to the revenue and pricing principles.

These values are set out in table 9.6 and are used as inputs to the PTRM to determine the Victorian DNSPs' annual revenue requirement during the 2011–15 regulatory control period.

The AER has also determined, under clause 6.3.2(a)(2) of the NER, that it will apply the same method to index the RAB as that used to escalate the form of control mechanism over the 2011–15 regulatory control period. This forms part of the calculation in determining the value of the opening RAB for the 2016–20 regulatory control period.

In accordance with clause 6.12.1(18) of the NER, the AER has determined to use actual depreciation for establishing the RAB for the commencement of the 2016–20 regulatory control period.

The AER's decision on the opening RAB can also be found in the distribution determinations for CitiPower, Powercor, JEN, SP AusNet and United Energy.

Table 9.6 AER conclusion on Victorian DNSPs' opening RAB ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 176.8	1 194.1	1 197.6	1 206.5	1 233.1
Net capex	93.6	79.1	84.6	97.1	125.8
Depreciation	76.3	75.7	75.6	70.5	72.0
Compound return on 2005 capex difference					0.4
Closing RAB	1 194.1	1 197.6	1 206.5	1 233.1	1 287.3
Difference from proposed RAB					–0.3
Powercor					
Opening RAB	1 916.8	1 978.7	2 034.4	2 093.0	2 136.1
Net capex	182.0	176.5	181.0	168.0	207.2
Depreciation	120.1	120.9	122.4	124.9	126.1
Compound return on 2005 capex difference					–4.3
Closing RAB	1 978.7	2 034.4	2 093.0	2 136.1	2 212.8
Difference from proposed RAB					–1.9
JEN					
Opening RAB	654.4	676.1	698.1	695.1	722.1
Net capex	64.4	66.3	42.2	73.3	91.8
Depreciation	42.7	44.3	45.1	46.3	46.8
Compound return on 2005 capex difference					–10.6
Closing RAB	676.1	698.1	695.1	722.1	756.5
Difference from proposed RAB					–9.7
SP AusNet					
Opening RAB	1 582.8	1 633.0	1 680.4	1 782.6	1 917.4
Net capex	134.1	139.9	200.8	238.4	256.1
Depreciation	84.0	92.5	98.5	103.7	109.2
Compound return on 2005 capex difference					10.6
Closing RAB	1 633.0	1 680.4	1 782.6	1 917.4	2 074.9
Difference from proposed RAB					–4.8
United Energy					
Opening RAB	1 388.6	1 381.5	1 359.0	1 334.3	1 357.6
Net capex	97.7	83.9	85.4	116.8	124.9
Depreciation	104.8	106.4	110.1	93.4	82.6
Compound return on 2005 capex difference					–19.7
Closing RAB	1 381.5	1 359.0	1 334.3	1 357.6	1 380.2
Difference from proposed RAB					–1.0

10 Depreciation

This chapter sets out the annual allowances for regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB). The annual regulatory depreciation allowance is an amortised value of the RAB, derived using a specified depreciation schedule that reflects the nature of the assets over their economic lives. Regulatory practice has been to assign a regulatory life (standard life) to each category of assets that equals its expected economic life.

10.1 Regulatory requirements

Under clause 6.12.1(8) of the National Electricity Rules (NER), the AER must make a decision on whether or not to approve the depreciation schedules submitted by the DNSPs and, if the AER decides against approving them, a decision determining depreciation schedules in accordance with clause 6.5.5(b).

Clause 6.5.5 of the NER sets out the requirement for depreciation for each regulatory year. Clause 6.5.5(a)(1) of the NER provides that depreciation must be calculated on the value of the assets included in the RAB at the beginning of the regulatory year.

A building block proposal must contain depreciation schedules that conform to the following requirements set out in clause 6.5.5(b) of the NER:

1. the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets
2. the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of the asset or category of assets was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system
3. the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

10.2 AER draft decision

The AER identified the following issues related to the Victorian DNSPs' proposed regulatory depreciation amounts:

- a minor correction to CitiPower's remaining asset lives for new capex for 'distribution systems assets' and 'non-network general assets-other' to reflect the correct standard asset life
- rejection of United Energy's proposal of $51.6 million ($, 2010) of accelerated depreciation

- increasing the standard life of SP AusNet's 'non-network general assets-other' category to 5 years
- minor amendments to JEN's remaining asset lives to reflect the appropriate expenditure timing assumptions
- changes made to Victorian DNSPs' roll forward calculations, which had indirect impacts on forecast depreciation amounts.

The AER determined the Victorian DNSPs' regulatory depreciation allowances for the 2011–15 regulatory control period as set out in table 10.1.

Table 10.1 AER draft decision on regulatory depreciation ($’m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	35.2	38.4	41.9	45.6	49.6	210.6
Powercor	62.0	68.1	74.6	81.5	88.9	375.1
JEN	26.9	30.7	34.7	39.0	32.3	163.5
SP AusNet	90.9	47.3	53.8	49.3	40.2	281.4
United Energy	36.0	42.7	50.2	57.8	66.2	252.9

Source: AER, Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015, June 2010, p. 477.

10.3 Summary of Victorian DNSP revised regulatory proposals

CitiPower and Powercor accepted the approach set out in the draft decision in relation to the calculation of depreciation and asset lives, except for the AER's minor adjustments and corrections to their RAB roll forward models.[1]

JEN submitted that the average life for a particular asset category is a function of the relative weightings of expenditure on the asset types in the category. JEN argued that the AER needed to recalculate the standard lives of all asset categories to reflect its final determination on capital expenditure.[2]

SP AusNet accepted the asset lives set out in the draft decision. It recalculated its proposed depreciation allowance using the asset lives specified in the draft decision and applying the updated opening RAB value and capex forecasts.[3]

United Energy proposed two additional asset classes, neutral screen services and overloaded transformers, to be included for the calculation of forecast regulatory depreciation. United Energy contended that these assets should be depreciated fully

1 CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 336; Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 327.
2 JEN, *Revised Regulatory Proposal 2011–15,* 20 July 2010, pp. 219–20.
3 SP AusNet, *Electricity Distribution Price Review, Revised Regulatory Proposal*, July 2010, p. 301.

because they will not be in service at the end of the 2011–15 regulatory control period.[4]

The Victorian DNSPs' revised proposed depreciation allowances are set out in table 10.2.

Table 10.2 Victorian DNSP revised regulatory depreciation ($'m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	34.8	38.6	42.7	46.9	52.5	215.5
Powercor	62.2	70.6	79.3	88.1	99.8	400.0
JEN	27.0	32.9	39.5	45.4	45.5	190.2
SP AusNet	91.9	51.2	62.2	58.2	55.9	319.3
United Energy	41.4	49.7	60.8	71.2	79.5	302.6

Source: Victorian DNSPs' PTRMs.

The Victorian DNSPs' revised proposed asset categories and standard lives are set out in table 10.3.

Table 10.3 Victorian DNSP revised standard asset lives (years)

Asset category	CitiPower	Powercor	JEN	SP AusNet	United Energy
Sub-transmission	50.0	50.0	44.7	45.0	60.0
Distribution system assets	49.0	51.0	50.0	50.0	35.6
Standard metering	–	–	–	–	–
Public lighting	–	–	–	–	–
SCADA/Network control	13.0	13.0	10.0	5.0	5.0
Non network general assets—IT	6.0	6.0	5.1	5.0	5.0
Non network general assets—other	10.0	15.0	19.9	5.0	7.5
Equity raising costs	46.6	45.2	43.1	46.5	40.7
Neutral Screen Services	–	–	–	–	5.0
Distribution Transformers upgrades	–	–	–	–	5.0

Source: Victorian DNSPs' PTRMs.

4 United Energy, *Revised Regulatory Proposal for Distribution Prices and Services*, January 2011–December 20115, July 2010, p. 162.

10.4 Summary of submissions

No submissions were received on this matter.

10.5 Issues and AER considerations

10.5.1 Depreciation method

10.5.1.1 AER draft decision

Further to the depreciation calculations arising from the PTRM inputs and methods, United Energy proposed additional regulatory depreciation amounting to $51.63 million ($, 2010) over the 2011–15 regulatory control period.

The AER considered that the additional depreciation proposed by United Energy for sub-transmission and distribution system assets was an accelerated depreciation of its sub-transmission and distribution assets and reflected a departure from the straight line depreciation. The AER was particularly concerned with United Energy's justification of additional depreciation, given that:

- United Energy's rate of depreciation for its overall RAB over the 2006–10 regulatory period was the highest of the Victorian DNSPs.
- using data from the ESCV's 2006 determination, the AER calculated that the implied remaining asset life for United Energy's sub-transmission assets was 43.3 years as at 2006. This compared to the much lower remaining life of 24.0 years from 2011 that United Energy proposed to the AER.
- modelling provided by United Energy showed that the calculation of the remaining lives already took into account the full range of assets in service, some of which lasted longer and shorter than their expected lives.

Accordingly, the AER considered that United Energy's additional depreciation had not been adequately justified as being in accordance with the requirements of clause 6.5.5(b)(1) and was not accepted by the AER.

10.5.1.2 Victorian DNSP revised regulatory proposals

United Energy proposed two additional asset classes, neutral screen services and overloaded transformers, to be included in the calculation of forecast regulatory depreciation. United Energy contended that the proposed asset classes are subject to large replacement programs and which will no longer be in service at the end of the 2011–15 regulatory control period.[5] United Energy submitted that these replacement programs were not included in the remaining life calculation in the initial regulatory proposal.

United Energy stated that it intended to replace 23.8 per cent of neutral screen services during the 2011–15 regulatory control period, which would lead to $27.3 million of the book value of services to be fully depreciated over a period of 5 years.[6]

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5 United Energy, *Revised regulatory proposal*, pp. 162–63.
6 United Energy, *Revised regulatory proposal*, p. 162.

United Energy stated that it intended to replace 3 per cent of transformers during the 2011–15 regulatory control period, which would lead to $5.6 million of the assets to be fully depreciated over the 2011–15 regulatory control period.[7]

10.5.1.3 Issues and AER considerations

Clause 6.5.5(b)(1) of the NER provides that the depreciation schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets. The AER has reviewed United Energy's proposed additional asset classes for the calculation of forecast regulatory depreciation. The AER considers that United Energy has demonstrated that the proposed asset classes are subject to large replacement programs and will no longer be in service at the end of the 2011–15 regulatory control period. Accordingly, the AER considers that a life of approximately 5 years reflects the expected economic life of these assets and would result in a depreciation schedule that is in accordance with clause 6.5.5(b)(1) of the NER.

The AER has also reviewed the modelling and asset replacement program provided by United Energy in support of its proposed opening RAB for neural screen services and distribution transformers, including further justifications and information requested of United Energy.[8] The AER has also reviewed the Electricity Safety Victoria's (ESV) assessment of the safety-related expenditure claimed by the Victorian DNSPs, including the neutral screen replacement program claimed by United Energy.[9] The AER has accepted the amounts of neutral screen services which were approved by the ESV and the amounts of distribution transformers substantiated by United Energy's additional evidence, which results in minor adjustments to United Energy's proposed opening RAB for neural screen service and distribution transformers.

10.5.1.4 AER conclusion

Based on the discussions above, the AER considers United Energy's calculation of remaining lives for the proposed asset classes to be in accordance with clause 6.5.5(b)(1) of the NER. The AER has made adjustments to the opening RAB for both neural screen service and distribution transformers to reflect the appropriate replacement amounts.

10.5.2 Asset classes, standard asset lives and remaining asset lives

10.5.2.1 AER draft decision

The AER noted that the calculation of all the Victorian DNSPs' remaining lives had been based on opening RAB values for 2011, which had been affected by the AER's draft decision. The AER had made adjustments to Victorian DNSPs' remaining lives as a result of changes to its RAB roll forward calculations.

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7 ibid., p. 162.

8 United Energy, *Revised regulatory proposal- appendix D-6 and D-21*, July 2010, p. 162; United Energy, *email to the AER in response to additional depreciation questions*, 26 August 2010, 14 September 2010, 28 September 2010 and 29 September 2010.

9 Electricity Safety Victoria, *Email to the AER on ESV summary of supported safety related items* 7 September 2010.

10.5.2.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor accepted the AER’s draft decision, except for the minor adjustments and corrections made by the AER that are set out in CitiPower's and Powercor's RAB roll forward models.[10]

JEN submitted that the average life for a particular asset category is a function of the relative weightings of expenditure on the asset types in the category. JEN argued that the AER needed to recalculate the standard lives of all asset categories to reflect the AER's final determination on capital expenditure.[11]

10.5.2.3 Issues and AER considerations

The AER has identified minor errors in its draft decision RAB forward models for CitiPower and Powercor in relation to capex input data and calculation. The AER has made corrections accordingly which resulted in minor adjustments to the remaining lives calculation and forecast regulatory depreciation.

The AER also identified unexplained differences in the standard lives for SCADA/network control and non-network–other assets between United Energy's revised regulatory proposal and its RAB roll forward model. United Energy confirmed that the correct standard lives are in its RAB forward model.[12]

The AER acknowledges that the average life for a particular asset category is a function of the relative weightings of expenditure on the asset types in the category under the weighted average method. However, the AER considers that JEN's proposed adjustment to standard lives is excessive and unnecessary, particularly when there is no standardised method to calculate or update standard lives. In addition, the AER does not consider that new capital expenditure will significantly affect weighted average RAB lives. Accordingly, the AER has not made adjustments to average lives of any DNSP in light of changes to capital expenditure allowances.

10.5.2.4 AER conclusion

Based on the considerations above, the AER has adjusted the remaining lives for CitiPower and Powercor, under clause 6.5.5(b)(1) of the NER.

10.6 AER conclusion

The AER has assessed each of the Victorian DNSPs’ proposed asset life inputs to their PTRMs that are used to calculate regulatory depreciation in accordance with clause 6.5.5 of the NER.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined the Victorian DNSPs' regulatory depreciation allowances for the 2011–15 regulatory control period in accordance with clause 6.5.5(a)(2)(ii), as set out in table 10.4.

[10] CitiPower, *Revised regulatory proposal*, p. 336; Powercor, *Revised regulatory proposal*, p. 327.
[11] JEN, *Revised regulatory proposal*, pp. 219–20.
[12] United Energy, *email to the AER in response to additional depreciation questions*, 26 August 2010.

Table 10.4 AER conclusion on regulatory depreciation ($’m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	34.7	38.4	42.3	46.5	51.8	**213.7**
Powercor	62.1	69.9	77.9	86.3	96.8	**393.0**
JEN	26.6	31.7	37.7	43.0	42.9	**181.9**
SP AusNet	91.1	51.2	62.3	58.1	55.1	**317.7**
United Energy	41.0	49.1	59.9	70.1	78.0	**298.0**

11 Cost of capital

This chapter sets out the AER's consideration of the rate of return for the Victorian distribution network service providers (DNSP) for the forthcoming regulatory control period. The key issues considered include the weighted average cost of capital (WACC) parameters specified in the AER statement of regulatory intent (SORI), and issues raised in the DNSPs' revised proposals and submissions—principally the debt risk premium (DRP) and market risk premium (MRP).

11.1 Regulatory Requirements

The AER must determine the rate of return in accordance with clause 6.5.2 of the National Electricity Rules (NER). This clause provides that the return on capital building block must be calculated by applying the rate of return to the value of the regulatory asset base (RAB) as determined in accordance with clause 6.5.1 and schedule 6.2 of the NER.

Under clause 6.5.4 of the NER, the AER conducted a review of the WACC parameters (WACC review). The NER requirements and determinations in the SORI that are relevant to each of these parameters are discussed below.

The WACC review was limited in its scope with respect to the DRP. Clause 6.5.2(e) of the NER defines the DRP as the premium determined for a regulatory control period by the AER as the margin between the annualised nominal risk-free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk-free rate and a credit rating from a recognised credit rating agency. The AER is required under clause 6.5.4(d)(6) of the NER to review the credit rating underlying the DRP as part of the WACC review.

The expected inflation rate is not a parameter relevant to the determination of the WACC. However, it is used in the post-tax revenue model (PTRM)—for example to index the regulatory asset base—and is an implicit component of the nominal risk-free rate. For this reason the AER's determination of the expected inflation rate is discussed in this chapter. Clause 6.4.2(b)(1) of the NER states that the contents of the PTRM must include a method that the AER determines is likely to result in the best estimates of expected inflation.

11.1.1 Statement of regulatory intent

Under clause 6.5.4(a) of the NER, the AER conducted the WACC review of the following matters referred to in clauses 6.5.2 and 6.5.3 of the NER:[1]

- the nominal risk-free rate
- the equity beta

[1] The AER notes that gamma is defined in the NER as an input to estimate the tax building block rather than the WACC. That said, the AER was required to review gamma under clause 6.5.4(a) of the NER.

- the market risk premium (MRP)
- the maturity period and bond rates
- the ratio of the value of debt to the value of equity and debt
- credit rating levels
- the assumed utilisation of imputation credits.

On completion of the WACC review the AER issued the SORI regarding these values, methods and credit rating levels.[2] Under clause 6.5.4(g) of the NER, a distribution determination must be consistent with the relevant SORI unless there is persuasive evidence justifying a departure from a value, method or credit rating level set in the SORI. Clause 6.5.4(h) of the NER requires that in deciding whether a departure from a value, method or credit rating level set in the SORI is justified, the AER must consider:

> (1) the criteria on which the value, method or credit rating level was set in a SORI (the underlying criteria); and
>
> (2) whether, in light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in a statement inappropriate.

The values, methods and credit rating levels determined by the AER in its SORI are listed in table 11.1.

Table 11.1 WACC parameters in the SORI

Parameter	Value
Gearing level (debt/equity)	0.60
Nominal risk-free rate	10 year CGS
Market risk premium	6.5 per cent
Equity beta	0.80
Credit rating level	BBB+

Source: AER, *Statement on the revised WACC parameters (distribution)*, Statement of regulatory intent, 1 May 2009.

The AER determined in the SORI that the nominal risk-free rate is to be calculated:

- on a moving average basis of the annualised yield on Commonwealth government securities (CGS)
- using a maturity of 10 years

2 AER, *Statement of regulatory intent*, 1 May 2009.

- with the agreed averaging period being one which is as close as practically possible to the commencement of the regulatory control period
- in accordance with clauses 6.5.2(c)(1), 6.5.2(c)(2)(iii) and 6.5.2(c)(2)(iv) of the NER.

11.2 AER draft decision

The Victorian DNSPs initially proposed a nominal vanilla WACC of 10.86 per cent, based on an indicative averaging period.[3] The proposed methods, values and credit rating were consistent with the AER's SORI with the exception of the MRP and the risk free rate.

The Victorian DNSPs all proposed a MRP of 8 per cent. The AER considered the information provided in support of the regulatory proposals but found no persuasive evidence that justified a departure from a MRP of 6.5 per cent set in the SORI.

Regarding the risk free rate, JEN proposed an averaging period that the AER considered was not as close as practically possible to the commencement of the regulatory control period. However the AER accepted this on the basis of a ruling by the Australian Competition Tribunal which it regarded as a relevant factor justifying a departure from the SORI in the circumstances. The AER accepted the averaging periods proposed by the other DNSPs as they were considered to be consistent with the method outlined in the SORI.

Regarding the measurement of the DRP, the Victorian DNSPs proposed the use of Bloomberg's BBB fair value estimates to determine the benchmark corporate bond rate. This was based upon recommendations by the DNSPs' consultant, Pricewaterhouse Coopers (PwC).[4] The AER considered that both Bloomberg and CBASpectrum should be considered in setting the DRP, and tested the accuracy of fair value curves produced by both data services. The AER applied a 'standard errors' test to determine whether Bloomberg's or CBASpectrum's fair value estimates (or an average of the two) provided the most accurate estimate of a sample of BBB+ rated bond yields with respect to the relevant averaging period. The AER selected six corporate bonds to include in the sample. The AER excluded one bond (the Babcock Brown Infrastructure (BBI) bond) after determining it was an outlier, leaving a total of five bonds in the sample. Over an indicative averaging period of 1 to 19 March 2010, the AER considered that the use of CBASpectrum's BBB+ fair value curve provided the best available prediction of observed yields for the purpose of determining the yield on a benchmark BBB+ 10 year corporate bond.

In forecasting inflation, the AER was guided by the NER requirement that the appropriate methodology should result in the best estimate of expected inflation.[5] The

[3] CitiPower, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 308; JEN, *Regulatory proposal 2011-2015*, 30 November 2009, p. 163; Powercor, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 316; SP AusNet, *Electricity Distribution Price Review, Regulatory proposal*, 30 November 2009, p. 303; and United Energy, *Regulatory proposal for distribution prices and services*,, November 2009, p. 138.

[4] Pricewaterhouse Coopers, *Victorian Distribution Businesses Methodology to Estimate the Debt Risk Premium*, November 2009

[5] NER, clause 6.4.2(b)(1).

AER considered that the most reliable 10 year inflation forecast was a geometric average of the Reserve Bank Of Australia (RBA) short term forecasts (currently extending out two years) and the mid-point of the RBA's target inflation range for the remaining years in the 10 year period. Based on this approach and using the latest RBA forecasts, the AER determined an inflation forecast of 2.57 per cent was the best estimate for a 10 year period.

Table 11.2 outlines the WACC parameter values for the draft decision.

Table 11.2 AER draft decision on WACC parameters

Parameter	DNSP initial proposals	AER draft decision
Nominal risk-free rate	5.47%	5.65%
Real risk-free rate	2.93–3.00%	3.00%
Expected inflation rate	2.40–2.47%	2.57%
Gearing level (debt/equity)	60%	60%
Market risk premium	8.0%	6.5%
Equity beta	0.8	0.8
Debt risk premium	4.71%	3.25%
Nominal pre-tax return on debt	7.52–7.60%	8.90%
Nominal post-tax return on equity	11.87%	10.85%
Nominal vanilla WACC	10.86%	9.68%

Note: Numbers are for indicative averaging periods only

11.3 Victorian DNSP revised regulatory proposals

The Victorian DNSPs adopted a nominal vanilla WACC of 10.29 per cent in their revised proposals. The increase from the draft decision WACC reflects the DNSPs' revised DRP. The DNSPs adopted an updated risk free rate of 5.65 per cent, based on an indicative averaging period of 30 business days ending 31 May 2010.

The DNSPs rejected the draft decision DRP and submitted consultant reports from Competition Economists Group (CEG) and PwC, proposing a different methodology to test whether CBASpectrum or Bloomberg produces the more accurate estimate of the DRP.[6] On the basis of these reports, the DNSPs proposed a DRP of 4.28 per cent based on Bloomberg's BBB fair value estimates.[7]

6 Pricewaterhouse Coopers, *Methodology for calculating the debt risk premium*, July 2010; Competition Economists Group, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates* A report fro Victorian Electricity DBs, July 2010

7 CitiPower, *Revised Regulatory Proposal 2011 to 2015*, July 2010; Powercor, *Revised Regulatory Proposal 2011 to 2015*, July 2010; JEN, *Revised Regulatory Proposal 2011-15*, July 2010; SP AusNet, *Electricity Distribution Price Review 2011-2015, Revised Regulatory Proposal*, July 2010; United Energy, *Revised Regulatory Proposal 2011 to 2015*, July 2010

The DNSPs all made specific comments on the MRP and stated that although they did not agree with AER's reasons, they adopted the MRP of 6.5 per cent for their revised proposals.[8] However, they reiterated that a value of 6.5 per cent will most likely understate the MRP for the forthcoming regulatory period.

On 7 October 2010, the DNSPs submitted a further report prepared by PwC which updated the proposed DRPs of CitiPower, Powercor and United Energy, given the completion of their averaging periods on 27 August 2010.[9] This report provided an updated analysis of the tests it applied in its July 2010 report to estimates derived from Bloomberg, CBASpectrum and an average of the two, finding that Bloomberg's fair value curve is likely to reveal a reasonable reflection of market opinion.[10]

11.4 Submissions

The AER received submissions regarding the cost of capital from:

- Consumer Utilities Advocacy Centre (CUAC)
- Energy User Association of Australia (EUAA)
- Energy Users Coalition of Victoria (EUCV)
- Consumer Action Law Centre (CALC)
- TRUenergy.

CUAC, EUCV, CALC and TRUenergy argued that there is now evidence to support a MRP of 6 per cent, given that the SORI value of 6.5 per cent was set in the midst of the GFC, which has now largely passed and did not seriously impact on Australian financial markets.[11] The EUAA also agreed with the AER's draft decision to reject the 8 per cent MRP proposed by the DNSPs.[12]

The EUAA submitted a report from Mr. Bruce Mountain arguing that the Victorian DNSPs' proposed DRP and the AER's draft decision DRP is too high, and

8 CitiPower, Revised Regulatory Proposal, p. 353; Powercor, Revised Regulatory Proposal, p. 344; JEN Revised Regulatory Proposal, p. 225; SP AusNet, Revised Regulatory Proposal, p. 306; United Energy, Revised Regulatory Proposal, p. 185.

9 PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, 5 October 2010.

10 PwC, October 2010, p. 4.

11 Consumer Utilities Advocacy Centre, *Submission in Response to the AER draft electricity distribution determination for Victoria and the distribution businesses revised revenue proposals*, 19 August 2010. Energy Users Coalition of Victoria, *AER Draft Decision and Revised Regulatory Proposals in CitiPower, JEN, Powercor, SP AusNet and United Energy Applications: A response by Energy User Coalition of Australia*, August 2010. TRUenergy, *Victorian electricity distribution network service providers distribution determination 2011–2015: Draft decision*, 16 August 2010. Consumer Action Law Centre, *Review of the Revised Victorian Distribution Network Service Providers Proposals in Response to the AER Draft Decision for the 2011–2015 Regulatory Period*, August 2010.

12 Energy Users Association of Australia, *AER Draft Determination on Victorian electricity distribution prices for the period 2011-2015 and distributors'' revised proposal*, 19 August 2010, p. 35.

recommended an alternative approach to estimate the DRP that takes into account the actual financing cost of the DNSPs.[13]

The EUCV noted that the AER's SORI value for the equity beta is conservative and also made comments on the AER's draft decision for the Victorian DNSPs' gearing level. EUCV also considered that all inputs to the WACC are interrelated and varying one in isolation can create outcomes that do not reflect the actuality of the final figure used.[14]

11.5 Issues and AER considerations

11.5.1 Nominal risk-free rate

11.5.1.1 Statement of regulatory intent

The SORI states that the methodology for estimating the risk-free rate is based upon the yield on CGS with a maturity of 10 years, calculated over a 10 to 40 business day period commencing as close as practically possible to the start of the regulatory control period.[15]

Prior to the SORI, the AER determined a risk-free rate that is observed as close as practically possible to the date of the final decision. The averaging period was agreed upon between the AER and the network service provider. The AER notes that it is implicit in the NER that the averaging period for the DRP uses the same period, as the DRP is based upon the difference between the observed cost of debt and the nominal risk-free rate.[16]

11.5.1.2 AER draft decision

The AER determined a nominal risk-free rate of 5.65 per cent (effective annual compounding) based on the 15-day moving average for CGS yields with a 10 year maturity for the period ending 19 March 2010.

The averaging periods proposed by United Energy, CitiPower, Powercor (2 August to 27 August 2010) and SP AusNet (13 September to 8 October 2010) were accepted by the AER as they are in accordance with the SORI. For JEN's averaging period (19 April to 31 May 2010), the AER accepted the Tribunal's decision as a relevant factor justifying a departure from the SORI, however noted that it was still examining the full implications of the Tribunal's decision and its relationship to the requirements of the SORI as well as to the broader NER framework.[17]

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13 Energy Users Association of Australia, *AER Draft Determination on Victorian electricity distribution prices for the period 2011-2015 and distributors'' revised proposal*, 19 August 2010.

14 Energy Users Coalition of Victoria, *AER Draft Decision and Revised Regulatory Proposals in CitiPower, JEN, Powercor, SP AusNet and United Energy Applications: A response by Energy User Coalition of Australia*, August 2010

15 Australian Energy Regulator, *Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters – Final Decision*, May 2009, p. 132

16 NER, cll. 6.5.2(b) and 6.5.2(e).

17 Australian Energy Regulator, *Victorian electricity distribution network service providers: Distribution Determination 2011–2015*, Draft decision, June 2010, p. 488.

11.5.1.3 Victorian DNSP revised regulatory proposals

The Victorian DNSPs have adopted the methodology for calculating the nominal risk-free rate as set out in the AER's draft decision, adjusting for the DNSPs proposed averaging period.

11.5.1.4 AER conclusion

The AER has determined the nominal risk–free rate in accordance with clauses 6.5.2(c)–(d) of the NER and the SORI. For this final determination, the resulting nominal risk-free rate is 5.65 per cent for JEN, 5.14 per cent for SP AusNet and 5.08 per cent for Citipower, Powercor and United Energy.

11.5.2 Market risk premium

11.5.2.1 Statement of regulatory intent

The SORI specifies a MRP of 6.5 per cent.[18] In the WACC review final decision the AER outlined the reasons behind the redetermination of the MRP from the previously adopted value of 6 per cent to 6.5 per cent:

> The AER considers that prior to the onset of the global financial crisis, an estimate of 6 per cent was the best estimate of a forward looking long term MRP, and accordingly, under relatively stable market conditions—assuming no structural break has occurred in market—this would remain the AER's view as to the best estimate of the forward looking long term MRP.
>
> However, relatively stable market conditions do not currently exist and taking into account the uncertainty surrounding the global economic crisis, the AER considers two possible scenarios may explain current market conditions:
>
> - that the prevailing medium term MRP is above the long term MRP [of 6 per cent], but will return to the long term MRP over time, or
> - that there has been a structural break in the MRP and the forward looking long term MRP (and consequently also the prevailing) MRP is above the long term MRP that previously prevailed.
>
> Accordingly, the AER considers that a MRP of 6.5 per cent is reasonable, at this time, and is an estimate of a forward looking long term MRP commensurate with the conditions in the market for funds that are likely to prevail at the time of the reset determinations to which this review applies.[19]

In forming its decision, the AER also considered the long term historical excess market returns:

- "grossed-up" for imputation credits for a utilisation rate of 0.65
- estimated relative to the yield on 10 year CGS, and

[18] AER, *Statement of regulatory intent*, 1 May 2009, p. 7.
[19] Australian Energy Regulator, *Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters – Final Decision*, May 2009, p. 238.

- over a range of long term estimation periods considered appropriate (1883-2008, 1937-2008, 1958-2008).

Taking these into consideration, the AER found that long term historical MRP fell within a range of 5.7 to 6.2 per cent.[20]

11.5.2.2 AER draft decision

The DNSPs initially proposed an MRP of 8 per cent which represents a departure from the 6.5 per cent MRP specified in the SORI. The Victorian DNSPs' proposals were based upon advice provided by Dr Steven Bishop and Professor Bob Officer on behalf of Value Advisor Associates.

Officer and Bishop examined the underlying basis and reasoning that the AER applied to support its determination of a 6.5 per cent MRP in the SORI. Officer and Bishop:

- noted that they were asked to recommend a MRP that is expected to prevail over the period 2011–15
- advocated under 'normal' market conditions the use of a long term historical average of excess returns[21]
- did not consider conditions for 2011–15 are representative of 'normal' conditions and therefore the MRP expected to prevail over this period is well above 6.5 per cent
- proposed a 7 per cent estimate for the long term equilibrium MRP instead of the AER's 6 per cent estimate and also anticipated a forward looking MRP of 12 per cent
- formed a view based upon forward looking MRPs and the long term equilibrium MRP, that a MRP of 8 per cent should apply to DNSPs for the 2011–15 regulatory control period.[22]

The AER noted it had considered the same approach in recent distribution determinations. It did not consider the implied volatility and glide path analysis presented by Officer and Bishop to be persuasive, and in any case was inconsistent with estimating the MRP over a 10 year period (being the investment term set for the risk-free rate in the SORI).

11.5.2.3 Victorian DNSP revised regulatory proposals

The Victorian DNSPs adopted a MRP value of 6.5 per cent for their revised proposals, but stated that they did not accept the underlying analysis underlying the AER's adoption of this value in the draft decision.[23]

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20 AER, *Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters – Final Decision*, May 2009,, p. 237

21 Officer and Bishop refer to this as the long term historical MRP.

22 R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p.17.

The DNSPs argued that, contrary to the AER's view that a MRP of 6.5 per cent is conservative in the current circumstances, market volatility continues to pervade capital markets and the outlook for the global economy and capital markets remain very fragile, putting pressure on the MRP.[24]

The Victorian DNSPs retained Officer and Bishop to review the AER's draft decision and submitted an updated report that further advanced their view that a departure from the SORI is appropriate. Officer and Bishop asserted that an MRP of 8 per cent for the forthcoming regulatory period is a better estimate given current market conditions and presented evidence to illustrate their assertion.[25] Officer and Bishop's estimate of 8 per cent MRP for the forthcoming regulatory period was based on their assumption that the long term equilibrium MRP is 7 per cent.

Officer and Bishop again used volatility analysis to estimate the likely value of the MRP one year forward and the 'average' MRP likely to prevail over the period 2011–2015. Evidence was presented showing that implied volatility of the ASX200 Index call option over 2010–15 is above 6.5 per cent and that 8 per cent is an appropriate value for the MRP to be applied for the 2011–15 regulatory control period. The report also responded to a number of criticisms made by the AER in the draft decision. Based on this, Officer and Bishop noted that a MRP of 6.5 per cent does not reflect current economic conditions while their approach recognises current market circumstances and should therefore constitute a material change in circumstances since the SORI.[26]

11.5.2.4 Submissions

The CALC recommended the AER reduce the MRP from 6.5 per cent to 6 per cent noting that the effects of the GFC, which were used to justify the DNSPs' proposed 8 per cent and the AER's SORI estimate of 6.5 per cent, have now reduced since the publication of the draft decision. With financial markets now recovering, the CALC suggested that the MRP has now declined to 6 per cent.[27]

The CUAC remained unconvinced that the MRP of 6.5 per cent is appropriate given the continue strengthening of the Australian economy and the relatively secure operating environment confronted by the Victorian DNSPs. It recommended that the AER should consider the possibility of a reduction in the MRP to the 6 per cent that was originally published in the explanatory statement of the WACC parameters in 2008.[28]

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23 CitiPower, Revised Regulatory Proposal, p. 353; Powercor, Revised Regulatory Proposal, p. 344; JEN Revised Regulatory Proposal, p. 225; SP AusNet, Revised Regulatory Proposal, p. 306; United Energy, Revised Regulatory Proposal, p. 185.

24 ibid.

25 Professor Bob Officer and Dr Steven Bishop, July 2010, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, p. 2.

26 Professor Bob Officer and Dr Steven Bishop, July 2010, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, p. 27

27 Consumer Action Law Centre, *Review of the Revised Victorian Distribution Network Service Providers Proposals in Response to the AER Draft Decision for the 2011–2015 Regulatory Period*, August 2010

28 CUAC, Submission to the AER, p. 2

The EUCV submitted that it concedes that the MRP is volatile and that at times it exceeds the long term average MRP. However, it also noted that because the MRP is volatile there are times where the MRP is lower than the long term average, and noted that none of the regulated DNSPs have suggested that a lower MRP should be used based on current market information. The EUCV noted that the AER had adjusted the MRP as a result of the GFC, however this had a marginal impact on the Australian economy, reinforcing the view that the MRP under the SORI is conservative. The EUCV agreed with the AER's draft decision stating that there is no need to increase the MRP above the level included in the SORI and suggested a reduction to the long term level used previously.[29]

TRUenergy supported the AER's decision of 6.5 per cent and noted that market evidence even suggests that a MRP of 6 per cent is more appropriate. However, it disagreed with the Victorian DNSPs' proposals for an MRP of 8 per cent, stating that market evidence does not support this value. TRUenergy submitted that the relatively unstable market conditions that informed the AER's decision to increase the MRP from 6 per cent to 6.5 per cent do not currently exist. As such TRUenergy could not see a firm case to increase the MRP to 8 per cent; rather the return to more stable conditions supports a move back to the traditional historical value of 6 per cent.[30]

11.5.2.5 Issues and AER considerations

Economic outlook and market conditions

The AER agrees with submissions that there is now evidence to suggest that market conditions have stabilised somewhat since the WACC review. In reports released by the International Monetary Fund (IMF), the RBA and the Organisation for Economic Co-operation and Development (OECD), the prevailing view is that economic conditions have improved since the AER's decision in May 2009 with the Australian economy displaying strong resilience and robustness during and after the GFC. In particular, on the state of the Australian economy the RBA stated that:

> Employment growth has been robust, business and consumer confidence is above average, the housing market has been strong, and there are signs that the period of business deleveraging is coming to an end. Collectively, these outcomes provide us with some confidence that the economy is now in a reasonably solid upswing. [31]

The IMF's prognosis of Australian economic condition was in similar vein:

> The global downturn had a fairly small impact on the Australian economy, as real investment barely contracted in 2009 and the unemployment rate went up by less than 2 percentage points. Not surprisingly, Australia's potential growth is estimated to have declined by just 1/3 per cent to 3.1 percent in 2009.[32]

The OECD's assessment of the Australian economy further corroborates with the IMF's view of the Australian economy:

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29 EUCV, Submission to the AER, p. 49

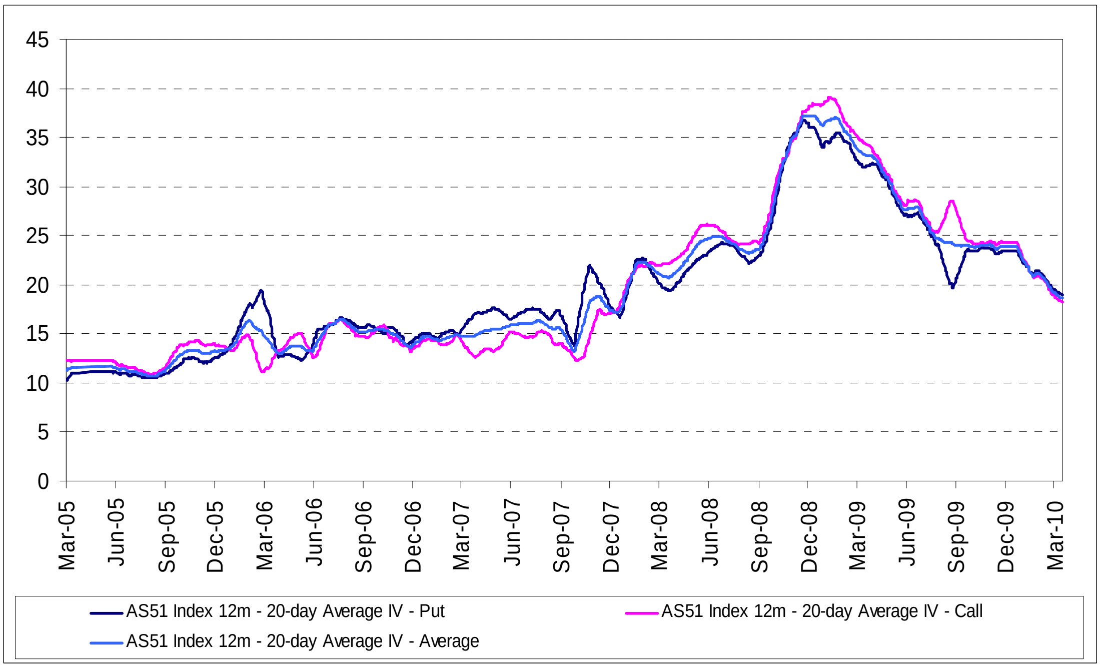
30 TRUenergy, Submission to the AER, p. 4-5

31 http://www.rba.gov.au/speeches/2010/sp-ag-250310.html, viewed 26 October 2010.

32 Yan Sun, 'Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis', IMF Working Paper, WP/10/27, May 2010, pp. 19

After weathering the crisis well in 2009, the Australian economy is projected to experience strong growth in 2010 and 2011, above is trend rate. Activity might expand by as much as 3¼ per cent and 3½ per cent in these two years, driven by booming exports and domestic demand. The unemployment rate is expected to fall below 5 per cent by the end of 2011, in a context of moderate inflation.[33]

Figure 11.1 Implied volatility

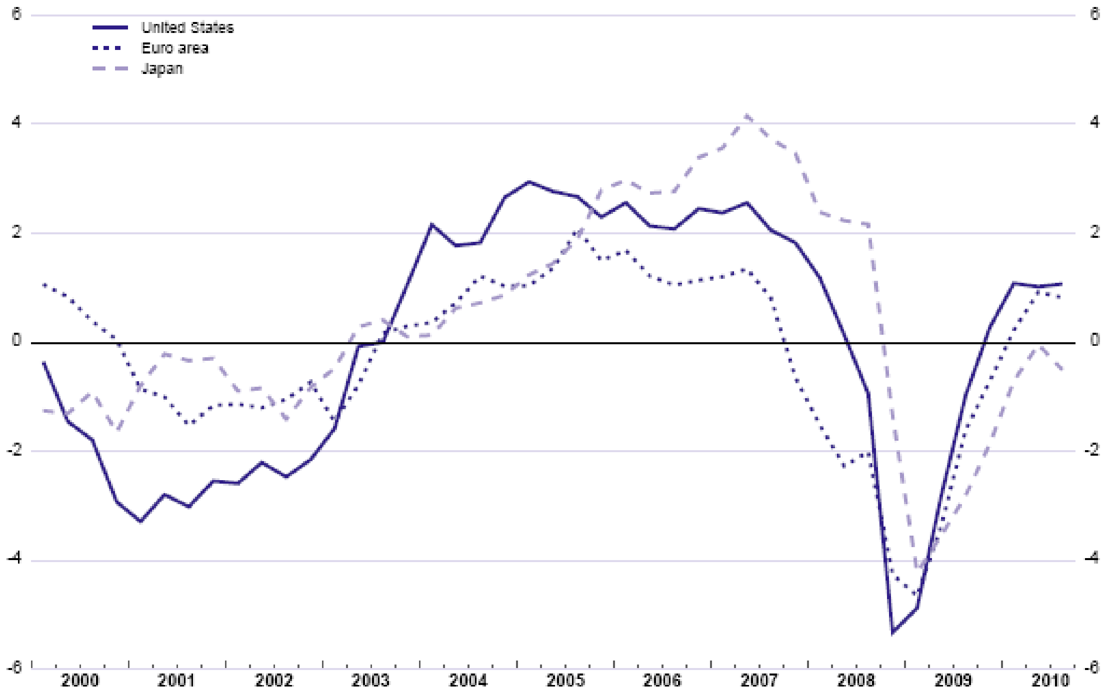


Source: Bloomberg; AER analysis

Figure 11.1 shows the 20-day moving average of implied volatility. In observing the graph the AER notes that market volatility, whilst still not back to pre GFC levels, has fallen substantially since the height of the GFC. This may suggest that there has been no structural break in expected market returns and a return to the historical long term value of 6 per cent for the MRP may be appropriate. This is supported by data published recently by the OECD regarding financial indicators in developed economies.

33 http://www.oecd.org/document/15/0,3343,en_2649_34573_45268687_1_1_1_1,00.html, viewed 26 October 2010

Figure 11.2 OECD financial conditions index



Source: OECD[34]

The AER notes recent comments made by the IMF expressing optimism on the recovery of the global economy since the global economic crisis but warns that recovery remains fragile. The IMF stated:

> With the world still trying to bounce back from the global economic crisis, the IMF says in its latest World Economic Outlook that the recovery remains fragile and uneven. Unemployment remains a major economic and social challenge. More than 210 million people across the globe may be unemployed, an increase of more than 30 million since 2007.[35]

The RBA also commented on recent economic developments:

> The global economy started to recover about a year ago from what was a very severe recession. That recovery is continuing, but the pace of growth differs significantly across the various regions of the world.[36]

The OECD's global economic outlook is along the same line warning that:

> Recent high-frequency indicators point to a slowdown in the pace of recovery of the world economy that is somewhat more pronounced than previously anticipated.[37]

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[34] OECD, *What is the economic outlook for OECD countries? An interim assessment*, 9 September 2010

[35] http://www.imf.org/external/pubs/ft/survey/so/2010/RES100610A.htm, accessed 26 October 2010

[36] http://www.rba.gov.au/speeches/2010/sp-dg-081010.html, viewed 26 October 2010

[37] OECD, *What is the economic outlook for OECD countries? An interim assessment*, 9 September 2010, p. 3

While there is evidence that Australia's economic conditions have improved since the GFC, the AER remains cautious to the extent of this recovery citing the views from prominent economic bodies' warning of the fragility of the recovery in the global economy. Furthermore, conditions in global capital markets remain uncertain as the aftermath of the GFC continues to be felt and resolved.

Consequently, the AER considers it appropriate to maintain the value of 6.5 per cent until there is persuasive evidence that market conditions have stabilised. The AER maintains the view that the long run historic MRP is 6 per cent, and that this should be adopted as market conditions return to those seen pre GFC. However, the AER remains cautious in its view of global market conditions. Accordingly, the AER believes that current indications of general market outlook do not justify a departure from the MRP of 6.5 per cent for the current determination consistent with the SORI.

Officer and Bishop's Implied Volatility Glide path approach

Officer and Bishop estimate equity market volatility as the volatility implied from the Black-Scholes option-pricing formula for 12-month ASX200 index call options. This represents a one year view of future volatility. Officer and Bishop consider that MRP derived from the implied volatilities of options on the stock market is a better predictor than using a historical average in current conditions.[38]

Officer and Bishop argued that the current volatility is well above the 'long term' MRP of 7 per cent, estimating that 'a one year forward view of the MRP is 11.9 per cent and that the 'average' forward view over the period 2011-2015 is 8 per cent'.[39]

The AER has previously expressed concerns about the robustness of the implied volatility and glide path analysis presented by Officer and Bishop.[40] In their latest report, Officer and Bishop provided arguments in response to the following concerns expressed in the AER's draft decision:

- In their glide path analysis, Officer and Bishop used a 5 year horizon to estimate the long term MRP which is inconsistent with the 10 year term of the risk free rate, and hence the implicit requirement to estimate the MRP over a 10 year period
- general concerns with using implied volatility to estimate the forward MRP
- their glide path reverts to a long term average MRP of 7 per cent, which contrasts to the 6 per cent used by the AER and other regulators and for which there is strong supporting empirical evidence
- the use of pre-1958 data which the AER considers to be inaccurate.

38 Professor Bob Officer and Dr Steven Bishop, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, July 2010, p. 2.
39 Professor Bob Officer and Dr Steven Bishop, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, July 2010, p. 2.
40 Australian Energy Regulator, *Victorian electricity distribution network service providers: Distribution Determination 2011–2015*, June 2010

Inconsistency with the 10 year risk free rate

In their response to the draft decision, Officer and Bishop argued that there is no inconsistency between their 5 year glide path analysis and the 10 year investment horizon underlying the AER's risk free rate calculation, stating:

> …the ten year bond yield is the best surrogate for the risk free rate and serves as an 'anchor' for one end of the distribution of risk. In both our historical examination of the MRP and our forward estimate of the MRP we have estimated an annual MRP. As noted, the annual MRP is anchored in an annual risk free rate from a 10 year Commonwealth Bond, and in neither the historical nor the forward-looking case have we estimated a 10 year MRP.
>
> There is absolutely no requirement to look at a ten year horizon in our geometric averaging to match the term of the risk free rate because the long term average annual MRP used reflects this 10 year rate.[41]

Maintaining consistency in the term of the risk free rate and the CAPM is an important consideration, which Officer and Bishop do not appear to dispute. The AER has examined the response put forward by Officer and Bishop on this matter and is still of the view that the implied MRP projection should be based on a time horizon which is consistent with the term of the risk free rate. Regardless of how Officer and Bishop have calculated the MRP, the figures will be used as an input in the CAPM equation for determining the required return on equity. Officer and Bishop have not adequately addressed the notion that the CAPM requires consistency between the time horizon risk free rate and the MRP.

The AER notes that Officer and Bishop have argued that their implied MRP will converge to the equilibrium MRP after 5 years so hence a 10 year model is unnecessary. However, this convergence to the equilibrium does not remove the inconsistency with the CAPM and the requirements under the SORI.

Furthermore, Officer and Bishop's methodology is based on Doran et al's model of time-varying expected returns on the S&P 500 Index, which estimates the implied volatility estimates of the MRP.[42] Doran et al used both long-term and short term-risk free rates to test their model. When using a short-term risk free rate they note that:

> …the model is misspecified since a long term growth rate should be accompanied by a long term-term risk free rate.[43]

For this reason they are careful to ensure consistency between the time horizon of the MRP and the risk-free rate. This lends further weight to the AER's conclusion that Officer and Bishop's glide path approach is inconsistent with the requirements under the SORI and is unlikely to accurately estimate the long term MRP.

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41 Professor Bob Officer and Dr Steven Bishop, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, Value Adviser Associates, July 2010, p. 20-21.

42 James Doran, Ehud Ronn and Robert Goldberg, A Simple Model for Time-Varying Expected Returns on the S&P 500 Index', Working Paper University of Texas, June 2005.

43 James Doran, Ehud Ronn and Robert Goldberg, A Simple Model for Time-Varying Expected Returns on the S&P 500 Index', Working Paper University of Texas, June 2005 Revised: October 8 2008, p. 14.

Concerns with Implied Volatility

The AER has expressed general concerns with using implied volatility analysis to estimate the forward-looking MRP.

In a separate report, Officer and Bishop maintained that the equilibrium (long-term average) MRP is the best forward looking MRP.[44] However, Officer and Bishop's implied volatility analysis seems to counter this view as their forward looking MRP is informed using short term volatilities in the options market. Whilst the AER notes the existence of short term variance in the MRP, adjusting it to account for this may be double counting, since equity/security prices will have already adjusted to any increase or decrease in the riskiness of those securities.

As noted above, Officer and Bishop informed their approach through 'empirical and theoretical support' from a single paper written by Doran et al.[45] However, Doran et al identified certain anomalies in their results where their use of implied risk measures to determine the MRP produced a negative implied equity risk premium during periods of 'irrational exuberance'.[46] If the AER was to follow such an approach to inform its decision on the MRP, it seems unlikely that regulated firms would accept a negative MRP during periods of robust economic conditions. Similarly, it also seems unlikely that the AER would be able to reduce the MRP in times of market stability such as in 2004 and 2006 when the forward-based MRP estimates were 4.5 and 4.9 per cent respectively.[47] Overall, if the AER were to inform its estimate of the forward-looking MRP based on short term volatilities, this would lead to greater uncertainty and volatility in regulated returns.

The AER also noted an important finding in Doran et al that is inconsistent with Officer and Bishop's analysis, namely that short run volatility had a surprisingly small impact on the medium term MRP. Specifically, they found that short term volatility only has a 10% weight in determining the medium term volatility and suggests 'that investors focus more on long-term volatility and are relatively insensitive to short-term volatility swings.'[48]

In considering Officer and Bishop's approach, the AER also looked at other empirical studies on implied volatility and found evidence suggesting implied volatility based on options can be upward biased and unreliable in forecasting the equity risk premium. One paper the AER considered was by Santa-Clara and Yan that studied ex ante risk premium derived from option prices from S&P 500 index options. In summary their study found that:

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44 Bob Officer and Steven Bishop, *Market Risk Premium: Further Comments*, Prepared for Energy Networks Association, Australian Pipeline Industry Association and Grid Australia, Value Adviser Associates, January 2009.

45 James Doran, Ehud Ronn and Robert Goldberg, A Simple Model for Time-Varying Expected Returns on the S&P 500 Index', Working Paper University of Texas, June 2005, p. 21.

46 James Doran, Ehud Ronn and Robert Goldberg, *A Simple Model for Time-Varying Expected Returns on the S&P 500 Index'*, Working Paper University of Texas, June 2005, p. 21.

47 Bob Officer and Steven Bishop, Market Risk Premium: A Review Paper Prepared for Energy Networks Association, Australian Pipeline Industry Association and Gird Australia, Value Adviser Associates, August 2008, p. 15

48 James Doran, Ehud Ronn and Robert Goldberg, *A Simple Model for Time-Varying Expected Returns on the S&P 500 Index', Working Paper University of Texas*, June 2005, p. 17

> ...the average premium that compensates the investor for the risks implicit in option prices, 11.8%, is about 40% higher than the premium required compensating the same investor for the realized volatility in stock market returns, 6.8%.[49]

The AER also considered a paper by Mikhail Chernov which studied the volatility of options and its role in forecasting the market risk premium. Using at-the-money options on two U.S equity indices and three foreign currency exchange rates, Chernov explains how the disparity between objective and risk neutral probability measures leads to the disparity between the realised and at-the-money implied volatilities. Chernov shows that informational inefficiency for the implied volatility of at-the-money options is a biased and inefficient forecast of future realised volatility.[50]

Based on its analyses, the AER has maintained its view that the uncertainties in Officer and Bishop's implied volatility analysis are significant enough to suggest that it is not a sufficiently robust method for setting the forward looking MRP.

Problems with pre 1958 data

In the Victorian draft decision, the AER questioned Officer and Bishop's use of 7 per cent as the long term average MRP. Officer and Bishop informed their long term MRP estimate using historical market risk premium, and catering for adjustments to the pre-1958 data by Brailsford et al (2008) and accounting for imputation credits.[51] The draft decision questioned the use of this data, however in response Officer and Bishop indicated that the longest period of data should be used when estimating the MRP noting that 'taking a short period can influence the average…and that the longest term is more likely to reflect the likelihood of unusual events'.[52] They asserted that in the absence of any additional errors in the data, the benefits of using longer time series data outweigh the errors that may exist. Officer and Bishop also adjusted the 2008 data (to give it smaller weight in reference to the GFC) because overweighting the GFC can change the long term average by circa 90 basis points (bps).[53]

Although consideration of a longer period increases the statistical reliability of the data, the AER considers that having regard to longer periods may compromise the quality of the data. This is because shorter term data series are likely to include higher quality data, as improved information sources have become available over time.[54]

In the WACC review, the AER addressed the issue relating to the length of the estimation period stating that concerns over data availability and data quality

49 Pedro Santa-Clara and Shu Yan, *'Crashes, Volatility , and the Equity Premium Lessons From S&P Options'*, Review Of Economics and Statistics, 92(2), May 2010, p. 450.

50 Mikhail Chervov, *'On the Role of Risk Premia in Volatility Forecasting', Journal of Business and Economic Statistics*, 25(4) October 2007, p, 411–426.

51 Professor Bob Officer and Dr Steven Bishop, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, Value Adviser Associates, July 2010, p. 23

52 Professor Bob Officer and Dr Steven Bishop, *Market Risk Premium: Comments on AER Draft Determination for Victorian Electricity Distribution Network Service Providers*, Value Adviser Associates, July 2010, p. 22.

53 ibid.

54 AER, Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters – Final Decision, May 2009, p. 200

increases along with the estimation period.[55] The AER notes that Brailsford et al examined the quality of market return data and government bill and bond data over time and that identifiable and material change in the quality of the underlying data occurred in 1883, 1937, 1958 and 1980. Concerns were expressed by the authors that the small sample of firms, exclusion of certain sectors, and government stock price controls would likely overstate the equity returns up to the mid–1950's. Additionally, Brailsford et al considered that Australian data prior to 1958 should be used with caution.[56] The AER agreed with this view noting estimation period that included pre 1958 data was likely to overstate historical excess returns during this period because of the biases identified by Brailsford et al.[57] Accounting for historical data from these three sub periods and adjusting it to the relative yield on 10 year CGS and 'grossing-up' for imputation credits, the AER found the MRP to fall between 5.7 to 6.2 per cent. Ultimately, the AER considers the long run MRP to be 6 per cent and is not persuaded by Officer and Bishop's arguments.

The effect of Theta on the MRP

The interrelation between WACC inputs was also raised by the EUCV which considered that the WACC parameters cannot be estimated in isolation and mechanistically developed:

> All of the elements bear some relation to the others used in the development of the final value for WACC. To isolate one or two elements and accept the others does not recognise the inter-dependence between the elements.[58]

The AER notes that the DNSPs have failed to take into account the potential impact on the MRP through their proposed reductions in the utilisation of franking credits (see chapter 9).

In forming its decision in the SORI value of the MRP, the AER 'grossed-up' historical excess returns to reflect the value of 0.65 it determined for theta. After doing so, the AER found the estimate of the MRP to fall within a range of 5.7 -6.2 per cent.

In the WACC review, the AER examined the impact of different values of theta on historic values of the MRP. [59] In their revised proposals, United Energy and JEN proposed a reduction in the theta value of 0.65 to 0.23. This reduction would have the effect of reducing historic MRP values by approximately 30 basis points. As the AER has maintained its view that, based on information currently available, the appropriate value of theta is 0.65, the potential impact on the MRP is merely noted here for completeness.

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55 AER, *Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters* – Final Decision, May 2009, p. 201

56 AER, *Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters – Final Decision*, May 2009, p.201.

57 ibid p. 202

58 EUCV, *Submission to the AER*, 19 August, p. 74.

59 AER, *Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters – Final Decision*, May 2009, Table 7.2, p. 209

11.5.2.6 AER conclusion

The AER accepts the DNSPs' revised proposals to not depart from the MRP value of 6.5 per cent set in the SORI. Regarding their commentary and consultant report, the AER considers:

- commentary on financial markets indicates clear signs of stabilisation since the time of the AER's SORI and its decision to increase the MRP to 6.5 per cent
- Officer and Bishop's implied volatility and glide path analysis is subject to various limitations
- no evidence exists to support a long term historical average of 7 per cent for the MRP as assumed by Officer and Bishop
- an MRP of 6.5 per cent may be considered conservative when accounting for improved financial conditions since the onset of the GFC, however, recovery in the global economy and conditions in global capital markets remain fragile
- the AER considers an MRP of 6.5 per cent remains appropriate for the current determination.

11.5.3 Debt risk premium

11.5.3.1 AER draft decision

The Victorian DNSPs initially proposed an indicative DRP of 4.71% based on PwC's recommendation to use Bloomberg's fair value curve.[60] This recommendation was based on Bloomberg's estimates passing a series of tests designed to establish the extent of any bias in the estimates and to identify any unacceptable amount of variability in the data used to produce them.

Given Bloomberg's BBB fair value estimates extend only to a seven year maturity, PwC recommended a linear extrapolation of the seven year BBB fair value curve using the 5 to 7 year margin to extrapolate out to a 10 year yield. PwC assessed the accuracy of its linear extrapolation by looking at the difference between the 10 year yield calculated using its extrapolation method and the 10 year yield depicted on Bloomberg's BBB fair value curve, which resulted in a 16.2 basis point median difference. PwC acknowledged that its extrapolation method differed somewhat from the approach adopted by the AER in previous determinations, however argued that a linear extrapolation would more accurately fit the functional form of the yield curve.[61] Overall, PwC found the reliability of the Bloomberg fair value curve to be adequate and the difference between their extrapolated 10 year yields to be relatively small compared to the observed 10 year yield from Bloomberg's BBB fair value curve.[62]

The AER did not receive any information from the Victorian DNSPs to justify the exclusion of CBASpectrum from its considerations, and accordingly examined data

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60 Pricewaterhouse Coopers, *Victorian Distribution Businesses: Methodology to Estimate the Debt Risk Premium*, November 2009.

61 Pricewaterhouse Coopers, *Victorian Distribution Businesses: Methodology to Estimate the Debt Risk Premium*, November 2009, pp. 30-37

62 ibid, p. 35

from both Bloomberg and CBASpectrum in its decision. As per previous determinations, the AER tested both fair value estimates using a standard errors test with a sample of BBB+ rated bond yields. For this purpose the AER selected six BBB+ rated bonds, but excluded one of the bonds (issued by Babcock and Brown Infrastructure [BBI]) after determining this was an outlier through the application of the Chow test. Over the indicative measurement period (1 to 19 March 2010) the AER found that CBASpectrum's BBB+ fair value curve provided the best available predictor of the observed yields of the sample of BBB+ bond yields.[63]

Accordingly, the AER determined a DRP value of 3.25 per cent for the draft decision using CBASpectrum's BBB+ fair value curve. The AER considered this to be the best available prediction of observed yields for the purposes of determining the DRP on the benchmark BBB+ 10 year corporate bond.

As the AER determined the use of CBASpectrum in the draft decision, the issue of extrapolating Bloomberg estimates was only addressed in the context of the methodology proposed by the DNSPs. The AER acknowledged that since 19 August 2009, Bloomberg only published a BBB fair value curve extending as far as seven years. The AER compared the outcomes of using various extrapolation methods during a time when Bloomberg's 10 year BBB fair value was published, finding that the spread between Bloomberg's AAA seven to ten year fair value curve provided a smaller mean squared difference compared to the linear extrapolation method recommended by PwC. As such the AER considered that a reasonable approach to extrapolate Bloomberg's BBB fair value curve out to 10 years was to use the spread between Bloomberg's seven to ten year AAA fair value estimates.

11.5.3.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs rejected the AER's draft decision approach, and submitted further reports from PwC and CEG, which critiqued the AER's methodology and put forward alternative methods to estimate the DRP. The Victorian DNSPs all proposed an indicative DRP of 4.28% (based on the same indicative averaging period).[64]

CEG criticised the AER's methodology for testing whether the CBASpectrum BBB+ fair value curve or the Bloomberg BBB fair value curve (or an average) provided a better estimate of the yield on BBB+ bonds with a 10 year maturity.[65] CEG argued that the AER made errors in its methodology by using a sample of only five bonds with an average maturity of only 3.6 years.[66] CEG labelled this a "wrong question error" whereby the AER was attempting to test the accuracy of fair values at 10 year maturity using information on bonds with shorter maturities. It asserted that the AER also made an error in excluding the BBI bond, noting that its above average yield in the sample was to be expected given it had the longest maturity. CEG's conclusion

63 AER, *Victorian electricity distribution determination 2011–2015*, Draft decision, June 2010, p. 520

64 Citipower, Revised Regulatory proposal 2011-15; Powercor, Revised Regulatory proposal 2011-15; JEN Revised Regulatory proposal 2011-15; SP AusNet, Revised Regulatory proposal 2011-15; United Energy, Revised Regulatory proposal 2011-15

65 Competition Economists Group, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, A report for Victorian Electricity DBs, July 2010

66 Ibid, p. 1

was that once these errors were corrected, the Bloomberg fair value curve would be found to provide the more accurate estimate of the DRP.[67]

CEG also provided an analysis using additional information to increase the number of bonds for comparison. It considered it inappropriate to exclude yield estimates of bonds issued in Australia by foreign companies, noting that credit ratings agencies do not assign a credit rating based on the nationality of the issuer. CEG argued that the sample should not be limited to BBB+ fixed rated bonds, and so included the implied fixed yields on floating rate bonds, as well as bonds of ratings other than BBB+ (ranging from BBB to A-).

The PwC report was a review of the AER's draft determination for the Victorian DNSPs as well as the final decisions for ActewAGL and Jemena Gas Networks (JGN) with respect to the DRP.[68] This report also updated PwC's analysis from the earlier November 2009 report submitted with the DNSPs' initial proposals, with respect to examining the reliability of Bloomberg estimates. PwC also argued that the AER made a number of errors in these decisions, such as the exclusion of the BBI bond from its sample, not testing the CBASpectrum curve beyond 5 or 6 years and the failure to consider a wider range of information sources on bond yields.

PwC included the BBI bond in its analysis, noting its importance as the longest dated bond in the initial sample, and found that the Bloomberg fair value curve provided a better fit of the available BBB+ rated bond yields. PwC also recommended the use of Bloomberg's AAA fair value curve to extrapolate both the Bloomberg BBB and CBASpectrum BBB+ curve beyond the range at which the bonds can be tested.[69] PwC recommended using Bloomberg BBB curve out to 6 years and extrapolating the curve to a 10 year value using the Bloomberg AAA curve between 6 and 10 years. PwC also noted that Bloomberg ceased publishing fair value curves for the AAA credit rating after 22 June 2010, recommending that, if the AAA curve was not available during the relevant averaging period, the latest available AAA curve be used to perform the extrapolation.[70] PwC also considered the AER's reliance on only Bloomberg and CBASpectrum fair value curves and a limited number of BBB+ rated Australian corporate bonds on issue inappropriately ignores other potentially useful sources of information that could assist in estimating the DRP.

PwC also provided an alternative estimate of the DRP, from a report by Mr. Terry Toohey. The DRP derived by Mr Toohey is from a linear regression on the spreads of a 10 year BBB+ rated Australian corporate bonds. The resulting DRP from this method was 405 basis points.[71]

11.5.3.3 Submissions

The EUAA commissioned Mr Bruce Mountain to assess the AER's draft decision DRP. Mountain proposed that the AER should adopt an alternative approach to setting

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[67] Competition Economists Group, *Testing the accuracy of Bloomberg vs CBASpectrum Fair Value Estimates*, A report for Victorian Electricity DBs, July 2010, p. 11.

[68] Pricewaterhouse Coopers, *Methodology for calculating the debt risk premium* - Revised report, 19 July 2010.

[69] ibid, p. 22.

[70] ibid, p. 17.

[71] Terry Toohey, *Debt risk premium for a benchmark Australian 10 year BBB+ corporate bond*, attachment to PwC report.

the DRP based on the actual financing arrangements of individual DNSPs.[72] Adopting the approach set out in the report would result in a DRP of no more than 120bps.

Mountain argued that the AER's draft decision DRP was well above the observed cost of debt for Australian electricity network providers, even at the height of the GFC. The report provides three sets of data on the observed cost of debt for recent utility debt raisings, which imply an average "actual" debt margin of 36 basis points.[73] Mountain also highlighted the cost of debt determined by Ofgem implies a DRP of 120 bps, and that previous regulatory (electricity) decisions in Australia were consistent with 120 bps, making the AER's Victorian draft decision around three times higher than these decisions. Mountain suggested that clause 6.5.2(e) of the NER, which is the most specific clause on the calculation of the DRP, is flawed and instead the AER should focus on setting the DRP such that it satisfies clause 6.5.4(e)(1) for a 'forward looking' rate of return and the over-arching objectives of the NEO. Mountain concludes:

> …considering that the AER has been unable to achieve a literal implementation of [clause 6.5.2(e)] anyway, the right course of action is for the AER to examine a wider range of evidence of the margins that distributors are actually paying in the markets in which they actually raise capital.[74]

The Victorian DNSPs provided a joint submission in response to the EUAA's and Mountain's report, which included further analysis from PwC.[75] The submission stated that there are a number of inconsistencies in the alternative approach outlined in the Mountain report, in particular that it does not satisfy the requirements of the NER and if adopted, would represent a significant departure from the SORI. They further noted that applying a benchmark is consistent with the general approach of incentive regulation and promoting the over-arching objectives of the NEO.[76] Furthermore, PwC also questioned the accuracy of the calculations used to analyse the 'observed' cost of debt involving particular DNSPs, insisting that the method used was opaque and potentially flawed.[77] The submission strongly argued that the alternative approach should not be considered in the final determination.[78]

11.5.3.4 Further consultation by the AER

On 27 September the AER issued a further consultation paper on the DRP to stakeholders who specifically commented on WACC related matters.[79] This paper

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72 Bruce Mountain, *Analysis of the Australian Energy Regulator's assessment of the Debt Risk Premium in its Draft Decision on price controls for the period 2010/11 to 2015/16 for the Victorian electricity distributors*, A report of the Energy Users Association of Australia, 13 August 2010.

73 Bruce Mountain, *Report on the AER's assessment of the Debt Risk Premium*, August 2010, p. 6

74 Bruce Mountain, *Report on the AER's assessment of the Debt Risk Premium*, August 2010, p. 28.

75 Victorian DNSP joint submission, *Submission in response to the Mountain report on DRP*, Prepared jointly by the Victorian Electricity Distribution Businesses, 24 September 2010

76 Victorian DNSP joint submission, *Submission in response to the Mountain report on DRP*, Prepared jointly by the Victorian Electricity Distribution Businesses, 24 September 2010, p. 5

77 Victorian DNSP joint submission, *Submission in response to the Mountain report on DRP*, Prepared jointly by the Victorian Electricity Distribution Businesses, 24 September 2010, p. 8–9

78 Pricewaterhouse Coopers, *Review of the Debt Risk Premium in the Mountain Report*, 22 September 2010, p. 3–4.

79 Australian Energy Regulator, *AER draft approach for measuring the debt risk premium for the Victorian Electricity Distribution Determinations*, 27 September 2010.

proposed a change in approach from the AER's draft decision in response to the following events:

- CBASpectrum ceasing the publication of its fair value yield curves[80]
- the decision by the Australian Competition Tribunal in the ActewAGL matter (ACT 1 of 2010) handed down on 17 September 2010
- A new 10 year BBB rated bond was issued by the Australia Pipeline Trust (APT), which is the financing arm of APA Group, a gas transmission and distribution network service provider.

The AER considered CBASpectrum's decision to no longer publish its fair value curves raised concerns over the transparency of the fair value estimates produced by Bloomberg and the prudence of now relying on them as the sole or primary source of information for determining the DRP.[81] These concerns arose in addition to the uncertainty over the reliability of Bloomberg and CBASpectrum estimates that had been raised in previous determination processes.[82] This uncertainty stemmed primarily from the fact that their methodologies are not transparent and their estimates have significantly diverged since the onset of GFC.

The Tribunal rejected the AER's approach for setting the DRP for ActewAGL (which was largely identical to that in the Victorian draft decision), and directed that the DRP should be calculated by taking the average of Bloomberg and CBASpectrum curves. In its reasons, the Tribunal made suggestions on how the AER might approach a future determination of the DRP, including widening the source of data points in distinguishing between competing curves. The Tribunal recognised that the difficulty in choosing between fair yield curves arose out of the lack of a sufficient number of long term bonds to determine yields. It noted that if a basis for distinguishing between published curves could not be found, it was appropriate to average the yields provided by each curve, so long as the published curves were widely used and market respected. The Tribunal also said it did not intend to discourage the AER from investigating other ways to estimate the DRP.[83]

In its consultation paper, the AER considered that, prima facie, the APT bond represented a useful benchmark corporate bond rate insofar as the yield calculation is transparent, it reflects a 10 year maturity, and it provides an acceptable proxy for the BBB+ credit rating. The AER also commented that its BBB rating means that its yields would be expected to produce a conservative estimate of the DRP. The AER noted that the nature of the APA Group's investments and markets provide a close match to those of electricity network service providers, which were potentially relevant when considering the overall cost of capital and revenue and pricing principles under the NEL.

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80 As communicated in an email from CBASpectrum to AER staff, 19 August 2010.

81 AER, D*raft approach for measuring the debt risk premium*, September 2010, p. 3.

82 For example, see CEG, Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates, A report for Country Energy, January 2010; Victorian DNSPs, Debt risk premium for use in the Initial AMI WACC period, Paper produced jointly by the Victorian Electricity Distribution Businesses, 1 June 2009; NERA, Critique of available estimates of the credit spread on corporate bonds, May 2005.

83 Application by ActewAGL Distribution [2010] ACompT4, p. 24, para 79.

The AER noted that:

> …the yields on the APT bond are likely to provide a close match to those of the benchmark corporate bond, however as it is only one relevant observation this proposition must be tested against other relevant information. Furthermore, Bloomberg estimates still potentially provide important information which can also be used in setting the DRP, but must also be subjected to appropriate scrutiny.[84]

The AER's proposed process for setting the DRP was to consider data provided by Bloomberg and the APT bond, in the context of a variety of bond information. The AER compared the DRPs derived from Bloomberg and the APT bond against a sample of fixed and floating rate bonds with ratings ranging from BBB to A, with a maturity of at least 7 years and observations reported on either Bloomberg or UBS. On the basis of this comparison, the AER was unable to definitively conclude whether either source of information could be solely relied upon for setting the DRP. In this context, and in light of the Tribunal's comments, the AER considered that it would be prudent to average yields from the two sources, and sought stakeholder comments on this conclusion and analysis.

11.5.3.5 Further submissions from stakeholders

The AER received responses from the following parties on its consultation paper:

- A joint submission from the DNSPs, with attached CEG and PwC reports
- The MEU
- The EUAA
- Orion Economic Services.

The DNSPs maintained that the AER should rely solely on the method proposed by PwC using the Bloomberg BBB 6 year fair value curve extrapolated out to 10 years using the Bloomberg AAA curves to estimate the DRP.[85] The DNSPs contended that no reliance should be placed on the CBASpectrum fair value curve and the AER's method should not involve any averaging of the yields on the bond issued by APT. They also argued that the AER's use of the APT bond is erroneous and that the manner in which it is used is not legally permissible. As a result, the AER should rely solely on Bloomberg fair value curves and place no weight on the APT bond in estimating the DRP.[86]

The Victorian DNSPs also submitted a PwC report which estimated the debt risk premium over the approved averaging period beginning 2 August 2010. PwC relied on Bloomberg's 6 year BBB rate fair value curve extrapolated using the change in the debt risk premium that was observed under the Bloomberg AAA fair value curve

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84 AER, D*raft approach for measuring the debt risk premium*, September 2010, p. 3

85 Pricewaterhouse Coopers, *Debt risk premium over the approved averaging period beginning 2 August 2010*, 5 October 2010.

86 Victorian Electricity Distribution Businesses, *Submission on the AER's consultation paper: AER draft approach for measuring the debt risk premium for Victorian Electricity Distribution Determinations*, October 2010.

between 6 to 10 years. Based on this, the PwC report recommended a debt risk premium of 413 bps.[87]

The Major Energy Users (MEU) provided a submission to the AER's consultation paper echoing the comments made by the EUAA and Mountain. The MEU contended that the DNSPs' actual cost of debt is well below any of the benchmarks being considered by the AER and is inconsistent with the NEO and the NER. It pointed out that the major form of debt finance is now in the form of bank debt, and there is virtually no market data for maturities greater than 6 years. It recommended that the AER should set a DRP which reflects the actual cost of debt an efficient DNSP would incur in an efficient debt structure. The MEU also argued that the use of short averaging periods creates the potential for excessive volatility and is inconsistent with the AER's approach in assessing the MRP which is a long term average.[88]

Orion also provided a submission to the AER noting it did not object to the use of actual bonds being used provided such bonds are true and fair representatives of their credit ranking. However, Orion submitted it does do not support the use of Bloomberg rates for regulatory purposes as the data is biased. To further this point, Orion cited work by CEG that questions Bloomberg's approach and its accuracy, implying that it should not be used for regulatory purposes.[89]

The EUAA also provided a submission questioning why the AER did not regard the suggestion in its previous submission (including the Mountain report) to examine the DNSPs' actual cost of debt, and noted the Tribunal's comment that "there seems to be little point in attempting to estimate the yield on a bond which is not commonly issued".[90]

11.5.3.6 Issues and AER considerations

The AER considers that the APT bond provides a good proxy of the benchmark corporate bond and the use of the APT bond as a data source for estimating the DRP is consistent with the requirements under the NER and SORI. In addition, the fact that the nature of the underlying risk and markets in which the APA Group operates resemble those of the Victorian DNSPs is a relevant consideration, in light of what the rate of return calculation is designed to achieve under the NER and the revenue and pricing principles.

However the AER acknowledges the arguments presented by the DNSPs regarding the reliability of Bloomberg, and the uncertainty surrounding the APT bond as a single observation. For this reason, the AER has maintained its proposed approach of using the yields derived from Bloomberg and from the APT bond. The AER has given more weight to the former for the purposes of this final decision. In forming this decision, the AER recognises that Bloomberg is demonstrated to accurately represent yields on shorter rated BBB bonds, while yields on the APT bond reflect an observed yield on a 10 year BBB bond which may be reflective of the efficient cost of debt for

[87] Pricewaterhouse Coopers, *Debt risk premium over the approved averaging period beginning 2 August 2010*, 5 October 2010, p. 2.
[88] MEU, *Discussion Paper on Measuring the Debt Risk Premium*, submission to the AER, p. 15.
[89] Orion, *Submission to the AER*, October 2010.
[90] EUAA, *Letter to the AER*, October 2010.

regulated network service providers. However, this is only one observation whilst the Bloomberg fair value curve is reflective of a range of BBB rated bonds.

Consequently, the AER considers that a 75% and 25% weighting to Bloomberg and APT respectively reflects a reasonable and practical approach in setting the DRP given uncertainties around relying too heavily on the single observation in the APT bond with respect to the benchmark corporate bond rate.

The following sections outline the key issues raised in consultation and the AER's considerations in setting the DRP:

- legal requirements
- the actual cost of debt
- the relevance and reliability of Bloomberg estimates
- the relevance of the APT bond
- the relevance of longer dated bonds
- implications of the Tribunal's recent decision on the ActewAGL matter
- extrapolation of Bloomberg to 10 years
- issues with JEN's averaging period.

Legal requirements

Clause 6.5.2(e) of NER states the DRP as:

> …the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency.

The maturity period and credit rating was set in the SORI to be 10 years in relation to the nominal risk free rate and BBB+ for the credit rating level.

The DNSPs stated that clause 6.5.2(e) of the NER requires the estimation of the DRP to be based on the derivation of a 'benchmark corporate bond rate' and not the derivation of a 'benchmark DNSP corporate bond rate'.[91] They acknowledged that the estimation of parameter values, such as the DRP, are only inputs to the estimation of the cost of capital as described in clause 6.5.2(b) and that the AER is required to bear this in mind in estimating parameter values.[92] However, they argued that the rules prescribe how the credit default risk of the benchmark efficient DNSP may be taken into account for the purpose of determining a cost of capital of the kind described in

[91] Victorian DNSPs, *Joint submission to the AER's consultation paper for measuring the debt risk premium*, October 2010, p. 17

[92] Victorian DNSPs, *Joint submission to the AER's consultation paper for measuring the debt risk premium*, October 2010, p. 16

clause 6.5.2(b) of the NER. They contended that it is impermissible to import into the NER provision defining the DRP a requirement that the DRP reflect the corporate bond rate for DNSPs or the benchmark DNSP or to otherwise consider only or place greater emphasis on a subset of the corporate bonds referred to in that provision.[93]

Clause 6.5.2(e) refers to "Australian benchmark corporate bond rate for corporate bonds" rather than the bond rate for the benchmark efficient DNSP. Therefore, the AER agrees that the estimation of the DRP should be based on the 'Australian benchmark corporate bond rate' rather than the bond rate for the benchmark efficient DNSP.

On the other hand, the AER considers that in exercising its discretion in determining the DRP for distribution determinations, it is permissible for the AER take into account what the rate of return is designed to achieve under the NER.

Clause 6.5.2(b) of the NER describes the rate of return for a DNSP for a regulatory control period as:

> …the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business of the provider.

The primary reason for giving weight to the APT bond as a data source for DRP estimation is that the bond resembles some of the key characteristics of the benchmark corporate bond (that is, it is a 10 year BBB rated bond). The fact that it is a bond issued by a firm with resemblance in the nature and degree of non-diversified risk as that faced by the Victorian DNSPs reaffirms the appropriateness of using this bond as a data source for estimating the DRP for the Victorian distribution determinations.

The DNSPs disputed the proposition that the risks faced by investors in APT would be similar as those faced by the Victorian DNSPs, given the DNSPs also own and operate regulated energy infrastructure. This is discussed further below.

In addition, the AER must take into account the revenue and pricing principles when exercising a discretion in making those parts of a distribution determination relating to direct control services. The revenue and pricing principles are set out in section 7A of the NEL. Those principles particularly relevant for the present purpose include:

> 2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.
>
> 3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

[93] ibid, p. 16

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(b) the efficient use of the distribution system or transmission system with which the operator provides direct control network

The fact that the APT bond is issued by a firm that operates in a market that is similar to that of the Victorian DNSPs and is faced with similar risks as those of the Victorian DNSPs is relevant in considering whether the AER's decision in relation to the DRP is consistent with the revenue and pricing principles.

Discussion on actual cost of debt

As summarised above, the Mountain report commissioned by the EUAA explored the actual cost of debt of several entities, finding that the AER's DRP would significantly overcompensate a number of regulated network service providers.[94] This sentiment is echoed by the recent MEU submission, which points out that the major form of debt finance is now in the form of bank debt, and there is virtually no market data for maturities longer than 6 years.

In addition to the information presented in these submissions, the AER understands that United Energy was able to obtain funding for its AMI arrangements at a margin of around 240 basis points over the swap rate or 50 bps below the benchmark set by the AER.[95] The AER is also aware that Spark infrastructure (owners of CitiPower and Powercor) refinanced $450m at a debt margin of around 200 basis points.[96] ETSA Utilities locked in 5, 7 and 10 year debt at an average margin of around 295bps in July 2009. On that basis ETSA will be receiving an allowance of around 130bps above the regulated allowance.[97]

The AER considers that setting the DRP based on the DNSPs' actual costs would be inconsistent with the NER and also the principles of incentive regulation, as pointed out by the DNSPs. However, considerations of the actual cost of debt for DNSPs provides a 'reality check' on the appropriateness of the DRP under the NEL's revenue and pricing principles and the NEO. The AER highlights that the DNSPs did not raise such considerations when arguing against the AER's proposed DRP.

On a more general note, the AER highlights comments made by stakeholders during this determination process and also by the Tribunal regarding the difficulties in estimating the yield on a 10 year BBB+ rated bond which is not commonly issued, and how this relates to the general task of setting an appropriate benchmark cost of debt. Such matters may be more appropriately addressed through changes to the relevant NER provisions.

94 Bruce Mountain, *Report on the AER's assessment of the Debt Risk Premium*, August 2010
95 Macquarie equities research report, 23 August 2010.
96 Goldman Sachs email, GSJBW Utilities: SKI - Refinances $450m of corporate debt.
97 MEU, *Measuring the Debt risk Premium, Submission to the AER* , 2010, p. 6.

The relevance and reliability of Bloomberg estimates

The Victorian DNSPs argued for the use of Bloomberg and rejected the AER's concerns that Bloomberg may be unreliable for the same reasons quoted by CBASpectrum. They considered the main reasons for CBASpectrum's decision to stop publishing fair value curves were problems with its models rather than a lack of data (as stated by the AER), and that the models employed by CBASpectrum and Bloomberg are different.[98]

Both CEG and PwC maintained that they consider Bloomberg still to be reliable. Consistent with its earlier reports for the DNSPs, PwC established three tests to examine the variance in underlying data feeds Bloomberg uses to produce its fair value estimates, as well as the central tendency of these estimates with respect to the underlying observations.

In examining the detail of PwC's report, however, Bloomberg would appear to fail the first of its tests, given that the variance of data feeds on the BBI/ DBCT bond from various sources was above its threshold of acceptability for the reference period 2 August 2010 to 27 August 2010.[99] PwC's tests are also based on data for only four bonds, which it argues matches the "AER's requirements", presumably those set out in the draft decision (i.e. BBB+ rated, fixed coupon bonds, which was used to test the relative accuracy of Bloomberg and CBASpectrum). The AER considers this to be a very limited set of information on which to draw conclusions about the reliability of Bloomberg's estimates.

Regarding the four bonds in its tests, PwC noted the following comments by market participants:

- Snowy Hydro Limited (maturity 25/2/2013) – Has a very high yield in the CBASpectrum data base, and may be influenced by concerns about a Snowy Hydro floating rate bond that has been credit wrapped by a defaulting party (Syncora Guarantee Inc, formerly XL Capital Assurance Inc).

- Wesfarmers Limited (maturity 11/09/2014) – With a positive ratings outlook, it is possible that this bond is already trading at a lower yield as an A- rated bond.

- Santos Finance (maturity 23/09/2015) – No concerns were expressed about this bond.

- DBCT Finance (maturity 9/06/2016) – Has a very high yield in the CBASpectrum data base, and may be affected by the default of its credit wrapper (Syncora Guarantee Inc, formerly XL Capital Assurance Inc).[100]

98 Victorian DNSPs, *Joint submission to the AER's consultation paper for measuring the debt risk premium*, October 2010, p. 11

99 PwC, *Debt risk premium over the approves averaging period beginning 2 August 2010*, October 2010, p. 8

100 PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, p. 10.

It is not clear what the implications of these comments are, although the default of Syncora and relationship with the DBCT bond yield is of particular relevance to the current decision.

Appendix B of the PwC report criticises the AER for considering the DBCT bond as an outlier in its draft decision. Regarding its own treatment of this bond, and its role in causing Bloomberg to fail the first of its tests, PwC noted:

> …we are confident that the single DBCT observation has not distorted Bloomberg's estimate of the fair value curve from the weight of market opinion. Bloomberg receives feeds for the DBCT bond from both CBA and the Royal Bank of Scotland (RBS). However, the debt risk premium adopted by Bloomberg is close to the debt risk premium for the DBCT bond based on the RBS feed (approximately 460 basis points), while CBA's feed implies a debt risk premium of approximately 1060 basis points. We believe that Bloomberg's yield (following RBS) is closer to the weight of market opinion, since the UBS yield for DBCT is only 100 basis points higher (i.e. approximately 560 basis points). Furthermore, the yield quoted by RBS is informed by an actual trade in the DBCT bond…
>
> In a telephone conversation with Royal Bank of Scotland on 17 June, 2010, we were informed that there was a trade in DBCT around September 2009, which was correlated with the marked downward revision in the bank's assessment of the DBCT yield.[101]

The AER notes the marked divergence in opinion on the yield of this bond from three data service providers. Moreover it notes with some concern the reliance placed by PwC on an assessment by RBS based on a trade that occurred around 11 months before the period examined by PwC.

The AER also highlights the following quotes from PwC's report which potentially raise questions about the accuracy of Bloomberg's estimates, or at least about PwC's tests of Bloomberg's reliability:

> We found a data discrepancy in the feeds that Westpac provided to Bloomberg over the last few days of the averaging period. It appeared that margins rather than yields were being provided for three bonds, which made these observations unusable. We alerted Bloomberg, and Westpac subsequently updated the numbers for one day. We have therefore excluded the suspect data, but do not expect this exclusion to have any appreciable influence on our tests, as this was a small percentage of the total opinions, and Westpac's yield estimates for these bonds were relatively constant earlier in the averaging period. We do not expect the exclusion to have any appreciable influence on our tests because the Westpac observations comprise a small percentage of the total opinions.[102]
>
> We note that during the last four days of the current reference period, Bloomberg included the DBCT bond in its estimate of the fair value curve, while for 16 days it was excluded. The Snowy Hydro bond was not included by Bloomberg in its estimate of the fair value curve on any day during the

[101] PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, pp. 8-9.

[102] PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, p. 8 (footnote 17).

> averaging period. The precise reasons for inclusion and exclusion of bonds by Bloomberg in this process are not known[103]

This latter comment highlights weaknesses in PwC's testing method and suggests that it cannot be relied upon as two of the bonds in its sample (i.e. 50% of its sample) appear to have not been used by Bloomberg for the majority of the period being examined. It is also the case that Bloomberg's BBB estimates are based on a much larger number of bonds, including those of different credit ratings. PwC's limited sample of bonds ignores a basic premise of the AER's consultation paper, namely the expansion of bond sample to examine alternative DRP sources.

CEG noted that Bloomberg is still publishing fair value curves and listed the following justifications for continuing to rely on published fair value curves:

- the relative expertise of the publisher of fair value curves
- the independence of the publishers from the regulatory proceedings
- continuity of regulatory precedent.[104]

The CEG report also tested the predictive accuracy of Bloomberg's BBB fair value curve and the APT bond and found that for each of the DNSPs' averaging periods the Bloomberg BBB fair value curve is preferred over the APT bond or an average of the two, when a full set of information is considered and a sum of squared errors test is applied.[105]

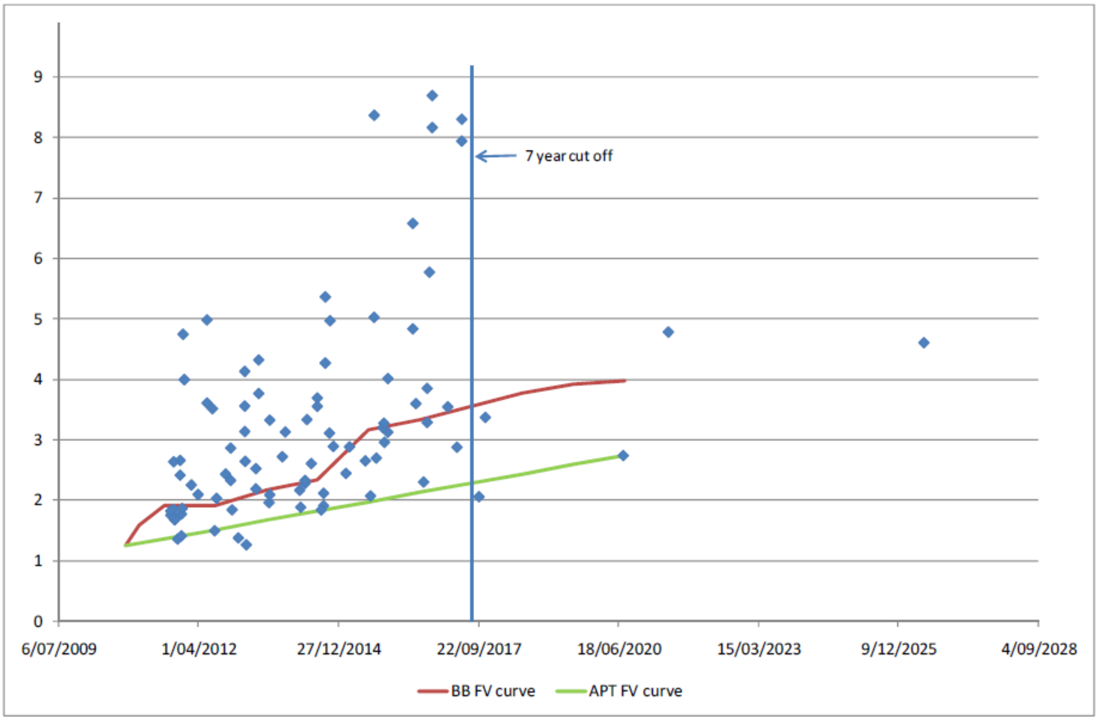
CEG's report presented a scatter plot of bond yields of lower ratings which it argued demonstrated that Bloomberg's BBB fair value estimates were reasonable. This plot is replicated in figure 11.3 below.

[103] PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, p. 10 (footnote 21).

[104] Competition Economists Group, *Use of the APT bond yield in establishing the NER cost of debt: A report for Victorian Distribution Businesses*, 12 October 2010, p. 7

[105] CEG, *Use of the APT bond yield to establish the NER cost of debt*, October 2010, section 3-5

Figure 11.3 CEG comparison of bond spreads



Source: Source: Bloomberg UBS and CBASpectrum, yields are averages of all available yield estimates for each bond. Powercor averaging period data used.

While not endorsing the entirety of CEG's analysis, the presentation of bond data suggests that Bloomberg's fair yield estimates are acceptably representative of yields on BBB rated bonds of maturities less than 7 years.

In acknowledging the difficulties presented by available data quality and quantity, the AER notes that CEG and the DNSPs have previously argued against using Bloomberg estimates. For example, Orion's submission to the AER cites a paper by CEG that previously examined Bloomberg's approach and noted that the level of discretion and proprietary approach in constructing its fair value curves would imply that it is not appropriate for regulatory purposes.[106]

Similarly, the AER notes that during the Victorian AMI budgets and charges determination process, the DNSPs raised several concerns with the reliability of Bloomberg estimates to generate a reliable measure of the DRP. This included Bloomberg's decision to cease publishing an 8 year BBB fair yield curve as appearing to 'represent an acknowledgement by Bloomberg that its curves are not a reliable indicator of the true value of longer term corporate bonds' and that 'the shortening of these curves therefore supports the view that Bloomberg's fair yield curves are not a reliable indicator of the 10 year corporate bond rate'.[107]

106 Competition Economists Group. *Estimating the cost of 10 year BBB+ debt: A report for Country Energy by Tom Hird, June 2009*. From Orion's submission to the AER, October 2010, p. 5

107 Victorian Electricity Distribution Businesses, *AER draft determination on 2009-2011 AMI budget and charges applications: Joint submission by the Victorian DNSPs on the debt risk premium*, 11 September 2009, pp. 20-21.

Notwithstanding, the AER accepts as reasonable in the circumstances, CEG's latest analysis which suggests that Bloomberg's BBB fair value curve reflects a range of BBB rated bonds currently trading in the market (i.e. with maturity below 7 years).

In summary, the AER considers that Bloomberg's BBB fair value estimates provide a reasonable reflection of corporate bond yields with a BBB rating and maturities up to 7 years.

Relevance of APT bond

In its consultation paper the AER highlighted that the APT bond provided a close match for the bond referred to in clause 6.5.2(e) of the NER, as it is a 10 year fixed coupon bond with a BBB rating. The AER also highlighted that the APA group has significant investments in markets which are a close match to those of electricity network service providers, hence reflect a similar nature and degree of default risk as the benchmark electricity network service provider.

In response, the DNSPs argued that the risk profile of the APA group is not similar to that of regulated electricity distribution networks and hence the AER's considerations of the APT bond cannot be said to satisfy the requirements of clause 6.5.2(b).[108] The DNSPs provided a detailed description of the APA Group's investments and markets, and noted that the only similarity between the APA Group and the DNSP is that many of the APA group's assets are regulated. The DNSPs note that the APA Group's interests in electricity assets are minor and its interests in gas assets are predominately in transmission rather than distribution, which are subject to revenue caps. Furthermore, the DNSPs note that the gearing ratio between the APA group and the DNSPs diverge, and as a result the credit default risk would also diverge.

The AER considers the DNSPs' arguments to be unreasonable in this regard. Any difference between the benchmark electricity network service provider and the APA Group is small, such that the APA Group was included as a close comparator to the benchmark firm in the WACC review.[109] The AER notes that submissions from all the Victorian DNSPs endorsed the inclusion of the APA Group in the comparator set used to estimate WACC parameters that would apply to the benchmark firm.[110]

Further, the AER also acknowledged in its consultation paper that there may be some divergence in the risk profiles of the APA Group and the DNSPs, however this would

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108 Victorian DNSP, *Joint submission to the AER's consultation paper for measuring the debt risk premium*, October 2010, p. 18-19

109 AER, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, Final Decision, 1 May 2009, p. 107, 121, 255, 259, 309, 322 and 323.

110 ETSA, CitiPower and Powercor, Letter re: Proposed weighted average cost of capital parameters, 2 February 2009, p. 2. JEN Limited, Letter re: Submission on explanatory statement and proposed statements of regulatory intent on the revised weighted average cost of capital, 2 February 2009, p. 2. United Energy Distribution, Letter re: United Energy's submission to the AER's review of the weighted average cost of capital parameters, 2 February 2009, p. 1, These submissions all explicitly endorse the JIA submission (which was co-authored by all the DNSPs, including SP AusNet) Joint Industry Association, Network industry submission, AER proposed determination, Review of the weighted average cost of capital parameters for electricity transmission and distribution, February 2009, pp. 43, 53, 65 and 111. See also SP AusNet, Letter re: Submission on AER's issues paper, Review of the weighted average cost of capital (WACC) parameters for electricity transmission and distribution, 24 September 2008, p. 1, 5.

result in a conservative DRP. This is because of the presence of unregulated and gas transmission networks in the APA Group, which are considered to be exposed to slightly more risk than the stable returns derived from electricity distribution businesses. Similarly, the BBB rating of the APT bond would further be expected to overcompensate with respect to the benchmark BBB+ rated bond yield. The DNSPs did not address these elements of conservatism, which are relevant in considering whether the use of APT as a data source for estimating the DRP will provide the DNSPs a reasonable opportunity to recover at least the efficient costs (section 7A(2) of the NEL).

The DNSPs also contended that the proposed use of the APT bond by the AER is inconsistent with its previous decision in relation to the Victorian AMI budgets and charges determinations. The DNSPs argued that the AER rejected the DNSPs' proposal to estimate the DRP from a single bond issued by Tabcorp, instead relying upon estimates derived from Bloomberg's BBB fair value curves.

For this previous decision the AER's concerns were in respect of the DNSPs' lack of justification for why the Tabcorp bond more adequately satisfied the entirety of the requirements under clause 6.5.2(e) than the alternative Bloomberg and CBASpectrum fair values, and their emphasis on the importance of the term "observed" in that particular clause. The decision stated:

> …the AER acknowledges the DNSPs' proposed approach to converting the Tabcorp issue into an annualised fixed yield to a 10 year maturity, submitted to satisfy the requirements of the revised Order. The AER does not have any in-principle issues with extrapolating and converting the Tabcorp floating rate to a 10 year maturity. However, the AER considers that it is possible to satisfy the requirements in relation to the averaging period and maturity through using other measures of the DRP, which would be more robust than making ad hoc adjustments to the Tabcorp bond yield.[111]
>
> In summary, the AER rejects the proposed DRP of 4.84 per cent based on the Tabcorp issue. The AER considers the DNSPs' misinterpretation and application of the terms in clause 6.5.2(e) led to the proposal of the Tabcorp issue as an alternative mechanism. However, the AER considers that sole reliance on the extrapolation of the Tabcorp issue is not robust enough in determining the DRP and it was not sufficiently established that the Tabcorp bond reflects the benchmark corporate bond. Accordingly, the Tabcorp bond does not satisfy the requirements of the revised Order.[112]

Hence the AER's considerations with respect to the APT bond in the current process are consistent with its rejection of the Tabcorp bond. The APT bond resembles some the key features of the benchmark corporate bond (that is, it is a 10 year BBB rated bond) and therefore it is appropriate to use the APT bond as a data source for estimating the DRP. On the other hand, the Tabcorp bond did not reflect the benchmark corporate bond as it is a 5 year maturity floating rate bond. In addition, the fact that the APT bond is a bond issued by a firm with resemblance in the nature and degree of non-diversified risk as that faced by the Victorian DNSPs reaffirms the

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111 AER, *Final determination- Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications,* October 2009, p. 128

112 AER, *Final determination- Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications*, October 2009, p. 60.

appropriateness of using this bond as a data source for estimating the DRP for the Victorian distribution determinations.

The relevance of other bonds

As noted in figure 11.3 above, CEG presented a comparison of Bloomberg's fair value estimates and the yield on the APT bond, showing that if bonds with less than 7 years to maturity were examined, the APT yields appear to be somewhat below what might be implied for longer maturing bonds of similar rating. By contrast, Bloomberg's fair value curve is shown to have a roughly even distribution of bonds above and below it. CEG argued this is anomalous and suggests that the APT bond is unrepresentative of its credit rating and should therefore not be given equal weight to Bloomberg's fair value curve. When regard is had to the full set of information, CEG considered that the Bloomberg BBB fair value curve had better predictive accuracy than the APT bond or an average of the two.[113]

CEG also considered the BBB+ rated BBI/ DBCT (Dalrymple Bay) maturing in 2021 to be just as plausible as—and even preferred to—the APT bond, if a single bond were to be selected. CEG noted the advantages listed by the AER in the consultation paper in favour of using the APT bond equally apply to the 2021 DBCT bond. CEG stated that the only material difference between the two bonds is that the 2021 DBCT bond has a yield that is above the Bloomberg fair value curve by about the same amount as the APT bond is below the Bloomberg fair value curve.[114]

The AER notes issues around the reliability of the bond yields for the other BBI/DBCT bond maturing in 2017 (excluded as an outlier in the AER's draft decision analysis), as there is considerable divergence in opinion of the yield of this bond, as noted by PwC:

> Bloomberg receives feeds for the DBCT bond from both CBA and the Royal Bank of Scotland (RBS). However, the debt risk premium adopted by Bloomberg is close to the debt risk premium for the DBCT bond based on the RBS feed (approximately 460 basis points), while CBA's feed implies a debt risk premium of approximately 1060 basis points.[115]

In the draft decision, the AER applied a qualitative assessment of the BBI/DBCT bond highlighting the market events supporting the exclusion of the BBI/DBCT bond.[116] While the AER acknowledges that the voluntary suspension has been lifted and the group has undergone a recapitalisation, the AER is still concerned that market perceptions of the bond have not shifted such that the yields are not simply reflective of its assigned credit rating. The AER notes the following comments made by the Tribunal regarding its treatment of the 2017 BBI/DBCT bond in the case of the ActewAGL gas decision:

> Turning to the AER's decision to exclude the BBI bond, the Tribunal notes that the AER had some basis to consider on qualitative grounds that the BBI bond was anomalous and that, although rated BBB+ at time of issue, its yield ought not to be taken into account in estimating the benchmark yield

113 CEG, *Use of the APT bond yield to establish the NER cost of debt*, October 2010, section 3-5
114 CEG, *Use of the APT bond yield to establish the NER cost of debt*, October 2010, p. 27
115 PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, p. 8-9
116 AER, *Victorian electricity distribution determination 2011–2015*, Draft decision, June 2010, p. 517

> on BBB+ bonds. The reasons included the suspension from trading of BBI shares. If nothing else, the suspension from trading would have had a significant effect on the yield, even though the credit rating assigned by Standard and Poor's remaining unchanged.[117]

The AER has also attempted to recently[118] extract observations of BBBI/DBCT bonds from Bloomberg and found that data were not currently available for those maturing in 2021, 2022 and 2026. Bloomberg's intermittent publication of data for this bond is consistent with PwC's observations that this bond has, in the past, not been included in its fair value estimates given wildly divergent data feeds on this bond, casting doubt over the reliability of this bond in comparative analysis.

The AER has also observed that the BBI/DBCT bond (including that maturing in 2021) is a callable bond. That is, the bond may be redeemed by the issuer before its maturity. As such, in addition to providing a return for the characteristics of its credit rating and maturity, the BBI/DBCT bond's yield also reflects a premium that compensates the bond holder for the bond being called prior to maturity. While CEG has argued that this additional premium can be separately identified,[119] the AER has been unable to do this at present given this bond is not priced on Bloomberg. In any case, that this bond has a callable feature raises issues in considering it for the purposes of estimating the benchmark corporate bond rate. This also relates to several other longer dated bonds the AER considered in its consultation paper.

The AER has considered CEG's analysis of shorter maturity bonds and acknowledges the importance of considering a wider range of data to estimate the DRP. However, the AER has concerns about placing undue weight on the relative yields of bonds with short maturities given that the DRP is estimated for a 10 year term. In doing so, the AER notes that CEG may itself be committing the "wrong question" error, by considering bonds with shorter maturities rather than having regard to the most relevant information to establish the reliability of DRP estimates at longer maturities.

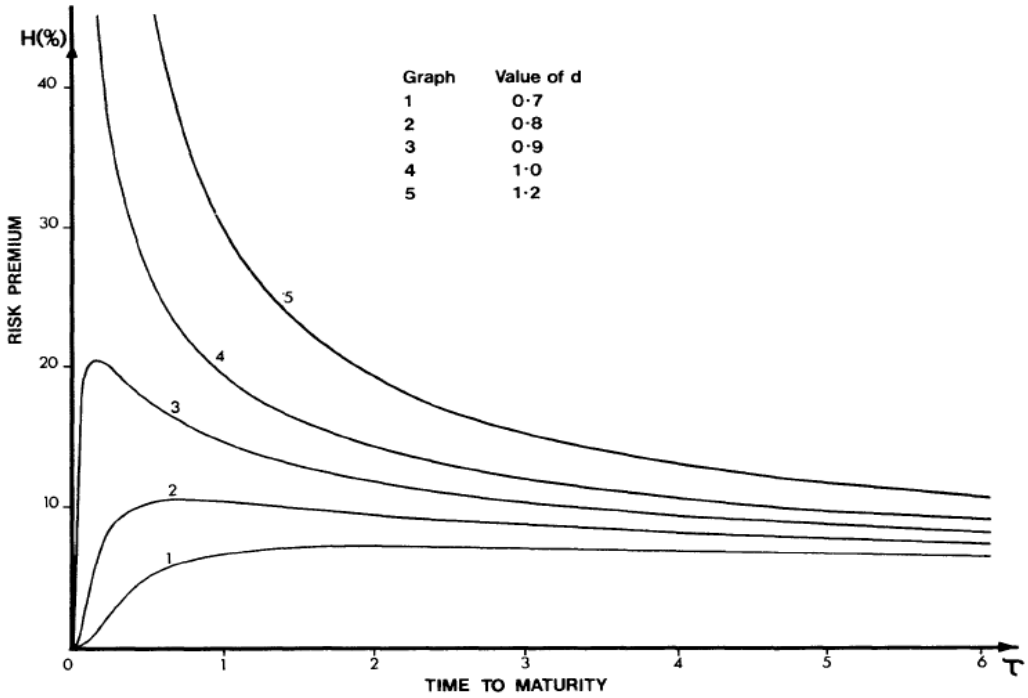
Nevertheless, the AER has attempted to understand the relationship between yields and maturity which has been notably explored by Merton, who described the theoretical foundation for the shapes, both slope and curvature, of the credit spread curve:

> …for high credit quality bonds the spread curve is either upward sloping or hump-shaped, while for low credit quality bonds the spread curve is downward sloping.[120]

In support of this, further empirical evidence found 'hump-shaped spread curves for double A to single B bonds'.[121] Figure 11.4 provides a graphical representation of this finding .

117 Application by ActewAGL Distribution [2010] ACompT4, p. 22, para 70.
118 Last attempted on 20 October 2010
119 CEG, *Use of the APT bond yield to establish the NER cost of debt*, October 2010, p. 65-69.
120 Merton (1974), Black and Cox (1976), Chance (1990), Shimko, Tejima, and van Deventer (1993), and Longstaff and Schwartz (1995).
121 Jia He, Wenwei Hu and Larry H. P. Lang, *Credit Spread Curves and Credit Rating*.

Figure 11.4 Merton credit spread curves



Source: C.G.C Pitts and M.J.P Selby, *The Pricing of Corporate Debt: A Further note*

This suggests that the credit spread for shorter maturity bonds is potentially wider than the credit spreads of bonds with longer maturity. As a result, it may be the case that yields on bonds with longer maturities will not necessarily be higher than those with shorter maturities, hence further underlining the importance of considering the actual behaviour of longer dated bonds when setting the DRP.

In addition, the AER considered the recommendation made by the Tribunal in determining a 'representative' sample of bonds which 'should contain bonds with a term to maturity close to 10 years'.[122]

Implications of tribunal decision

In the recent ActewAGL decision, the Tribunal remarked that the AER should consider all relevant sources of information to test the accuracy of the potential measure of the DRP. The Tribunal's decision highlights the need to take account of a wider variety of information sources when scrutinising alternative methods to estimate yields on long dated benchmark corporate bonds.

The Tribunal has commented on the AER's methodology of estimating the 10 year bond yield and the possibility of deriving an alternative methodology to overcome the limitations in the current approach:

> …the AER may need to reconsider its approach in light of more current strategies of firms in the relevant regulated industry. Further, there seems to

122 Application by ActewAGL Distribution [2010] ACompT4, p. 24 para 77

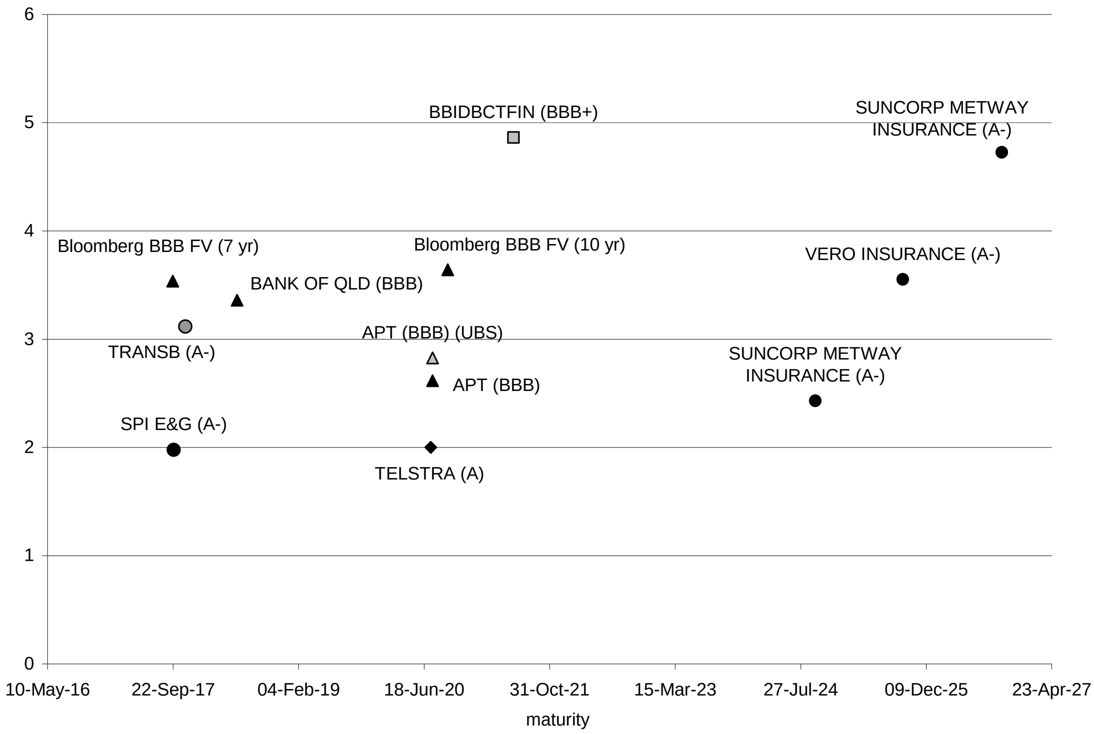
> be little point in attempting to estimate the yield on a bond which is not commonly issued.[123]
>
> …we do not discourage the AER from investigating other ways to estimate the debt risk premium.[124]

Given the paucity of BBB bonds of longer maturities currently trading in the market, the AER has considered the Tribunal's comments to consider additional sources of information when estimating the DRP.

CEG commented on the restriction the AER placed on the sample of bonds in its consultation paper and recommended that the AER should expand the sample of bonds by considering bonds with maturity less than 7 years. However, the AER is concerned about placing undue weight on shorter maturity bonds to establish the reliability of DRP estimates at longer maturities as noted above.

The AER's consultation paper considered the placement of Bloomberg's 7 year BBB fair value estimate and the 10 year APT bond in a sample of longer dated bond yields. This comparison is replicated in figure 11.5.

Figure 11.5 Spreads on long dated bonds



Source: Bloomberg, UBS, AER analysis.

The AER offered general observations regarding the placement of each bond, however found that it was not possible to definitively conclude that the extrapolated Bloomberg BBB fair value estimate should be preferred to the APT bond. On this

123 Application by ActewAGL Distribution [2010] ACompT4, p. 22 para 72
124 Application by ActewAGL Distribution [2010] ACompT4, p. 22 para 79

basis, the AER's proposed averaging of the two sources was not inconsistent with the Tribunal's comments in regard to averaging of available data:

> If the AER cannot find a basis upon which to distinguish between the published curves, it is appropriate to average the yields provided by each curve, so long as the published curves are widely used and market respected.[125]

The AER considers that in the current circumstances Bloomberg's fair value estimates are a reasonable source of information that can be used to inform the setting of the DRP. The AER further notes that Bloomberg is a market respected data service and it has relied on the fair value curves published by Bloomberg in the past.

Furthermore, the AER also considers the APT bond yield can reasonably be used as a suitable source of data for estimating the Australian benchmark corporate bond rate on which the estimation of the DRP is to be based, given the characteristics of the bond (that is, it is a 10 year BBB rated bond) and placement of the bond relative to the sample of longer maturity bonds assessed in the AER's consultation paper.

Furthermore, given the nature of APA Groups' business which closely mirrors that of the Victorian DNSPs, the AER considers that the use of the APT bond will produce a return on debt that is close to but conservative relative to the description of the cost of capital in the NER and that is consistent with the revenue and pricing principles under the NEL.

The AER considers both data sources to be relevant in considering the DRP and will give weight to both data sources. The AER is of the view that to put equal weighting on the data series provided by Bloomberg and on a single data point provided by the APT bond is not appropriate in the current circumstances. Thus, the AER considers that using the Bloomberg BBB fair value estimates has advantages over using the APT bond alone. However, there is evidence to suggest that Bloomberg's 7 year BBB fair value estimate is likely to overstate the relevant benchmark corporate bond yield as evidenced by comparing Bloomberg's fair value curve with the APT bond. Accordingly, the AER believes there is a need to balance Bloomberg's fair value estimates with other sources of information. This is consistent with the Tribunal's comments on the use of additional sources of data.

The AER has used its judgment and will therefore apply a lower weighting (25 per cent) on the yields from the APT bond and 75 per cent weighting on Bloomberg's BBB fair value estimates. The AER considers this to be a reasonable and practical outcome given the current circumstances for the purposes of this decision.

In using information from the APT bond, the AER notes that observations are available from both UBS and Bloomberg. While some small divergences in values are apparent from these two sources, this is not readily explicable, hence the AER will take a simple average of yields from UBS and Bloomberg when deriving the APT "yield" in calculating the DRP. The AER notes that APT yields available from CBASpectrum at present appear to be stagnant (i.e. the values do not change by day) and will not be used.

[125] Application by ActewAGL Distribution [2010] ACompT4, p. 24 para 78

Extrapolation of Bloomberg to 10 years.

In its latest report, PwC made the following comment:

> …since there are no BBB+ Australian corporate bonds currently on issue that have a term beyond a term of 6 years…it is impossible to test the accuracy of any fair value curves beyond this point.[126]

PwC have recommended using the Bloomberg BBB fair value curve out to 6 years and then using the Bloomberg AAA curve to extrapolate the Bloomberg BBB fair value curve beyond the range at which the curves can be tested.[127]

Regarding the extrapolation of Bloomberg's fair value estimates to 10 years, in its consultation paper the AER considered that the change between Bloomberg's AAA 7 and 10 year fair value estimates provided the most accurate approach to extrapolation. However, the analysis on which this conclusion was based suggested, in the event that Bloomberg's AAA estimates are no longer available, that Bloomberg's CGS estimates produced the next best (in terms of accuracy) method of extrapolation.[128]

Given the lack of AAA data currently available, the AER proposed to use the spread on CGS estimates to extrapolate Bloomberg's data. However, CEG has tested this approach against extrapolation based on the latest available AAA data (that is, using the historical data from the last day on which the Bloomberg AAA rated fair value curve was available at the required maturity). CEG found that extrapolation based on the latest available AAA data provided the best estimates of the BBB fair value curve beyond 6 years. CEG also comments that the AER assumption in using the CGS data will result in the DRP remaining constant between seven and ten years. This is contrary to empirical observations which suggest that the DRP should increase between seven and ten years.[129]

The AER notes that PwC's extrapolation is based on a Bloomberg BBB 6 year fair value estimate as this reflects its view of the limit to which one is able to test the accuracy of Bloomberg's estimates against BBB+ bonds on issue at this time. Since Bloomberg does not publish a 6 year fair value curve, PwC recommended applying a linear interpolation of the premiums between the Bloomberg 5 and 7 year fair value estimate, then extrapolating this point to 10 years.[130]

As noted above the AER has issues with PwC's method to examine the reliability of Bloomberg's estimates, thus has placed little weight on its conclusions. The AER also considers that CEG's comparisons reasonably establish the reliability of Bloomberg's estimates, including its 7 year BBB fair value estimate.

Overall the AER considers that using the spread on the AAA rated estimates to extrapolate Bloomberg's estimates to 10 years is preferable to using the spread on CGS estimates in light of CEG's arguments. Contrary to PwC's recommendation,

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126 PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, p. 6.

127 PwC, *Methodology for calculating the debt risk premium - Revised report*, July 2010.

128 AER, *Victorian electricity distribution determination 2011–2015*, Draft decision, June 2010, p. 517

129 CEG, *Use of the APT bond yield to establish the NER cost of debt*, October 2010, p. 55-56

130 PwC, July 2010, p. 22, footnote 23

however, the AER considers this extrapolation should be done from Bloomberg's 7 year BBB fair value estimate, and has used this method for this final decision.

JEN's averaging period

The AER has concluded that it will use the combined yields of the APT bond and Bloomberg's BBB fair value curve, applying a weight of 25 per cent and 75 per cent respectively to estimate the DRP. However, the AER notes that there are no yield data for the APT bond during JEN's averaging period accepted by the AER.

The AER has considered applying an average of the first 30 observations of the yield from the APT bond and applying this value with Bloomberg's BBB fair value estimate during JEN's averaging period to estimate the DRP. In its consultation paper, the AER examined the behaviour of the spreads on the APT bond with respect to other long dated BBB and BBB+ rated bonds since April 2010. The AER found no evidence to suggest that the APT bond was unusual and that current observations of the APT bond were unlikely to be materially different to what would have existing if the bond was traded in earlier periods.

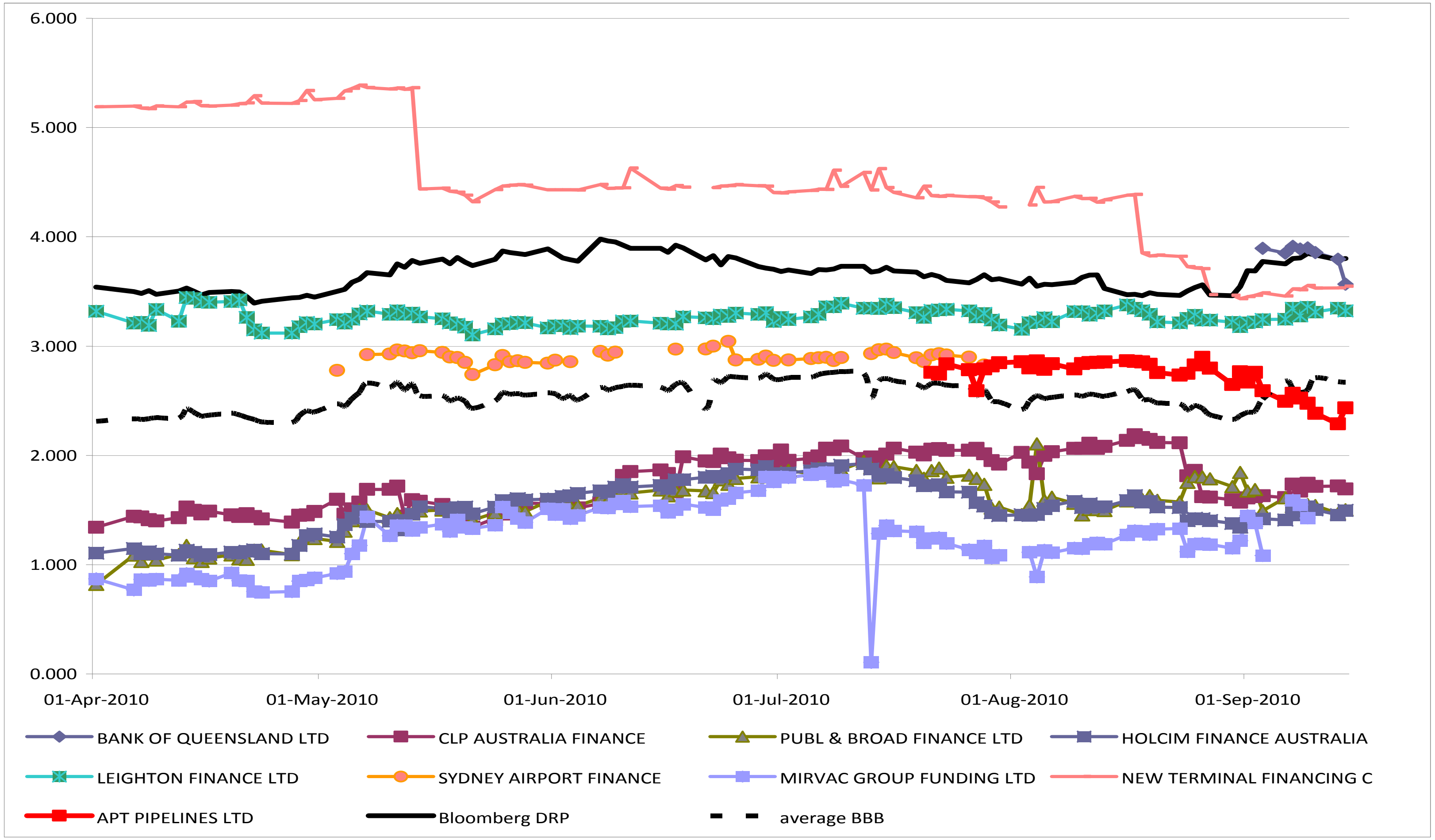
The DNSPs disagreed with the AER's findings:

> The AER's analysis in its Consultation Paper indicates that, to the contrary, the yield on the APT bond does not move with the spreads on BBB and BBB+ bonds as a group or the DRP that would be derived from extrapolating the Bloomberg BBB fair value curve to 10 years. For example, Figure 2 in the Consultation Paper discloses that, in the period from late August 2010, the yield on the APT bond and the DRP that would be derived from extrapolating the Bloomberg BBB fair value curve to 10 years have diverged significantly and have moved in opposite directions, with the former decreasing and the latter increasing.
>
> In any event, the AER's conclusion in the Consultation Paper that there has been no systematic or material change in the spreads on BBB and BBB+ bonds as a group or the DRP that would be derived from extrapolating the Bloomberg BBB fair value curve to 10 years is not supported by the AER's own analysis set out in that Consultation Paper. For example, Figure 2 in the Consultation Paper discloses that the DRP that would be derived from extrapolating the Bloomberg BBB fair value curve to 10 years has varied between approximately 3.5% and approximately 4% in the period 1 April to mid-September 2010 and by approximately 20 basis points in the period from the commencement of the JEN agreed averaging period until the issue date of the APT bond on 15 July 2010. By contrast, the Joint DBs consider that any movement of 10 basis points or more in the DRP is material.[131]

The time series comparisons in the AER's consultation paper are replicated in figures 11.6 and 11.7 below.

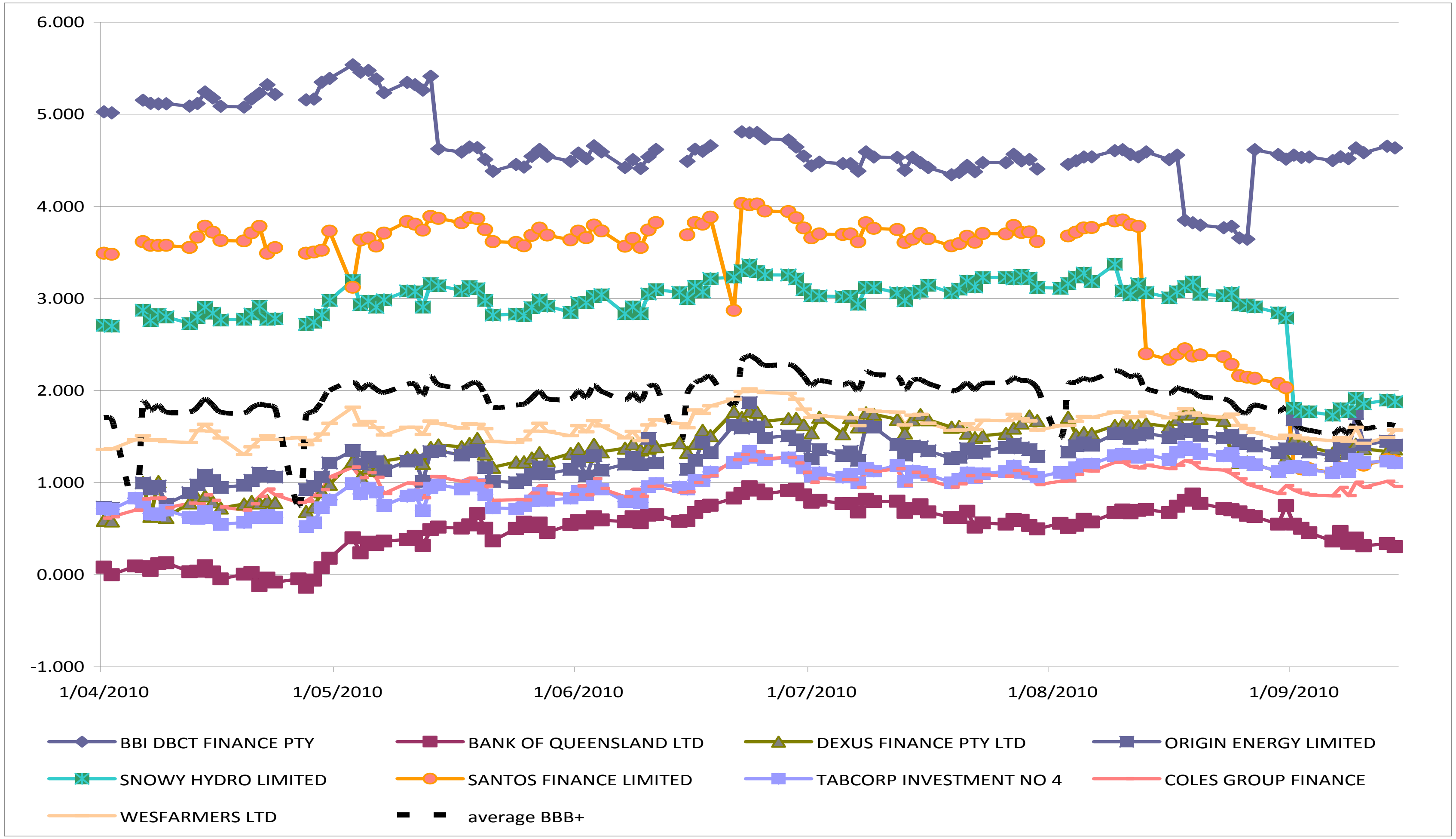
[131] Victorian DNSP, *Joint submission to the AER's consultation paper for measuring the debt risk premium*, October 2010, p. 27.

Figure 11.6 AER consultation paper comparison- spreads on BBB rated bonds



Source: Bloomberg

Figure 11.7 AER consultation paper comparison- spreads on BBB+ rated bonds



Source: Bloomberg

In response to the DNSP's arguments, the AER notes:

- movements in the DRP derived from the extrapolated Bloomberg fair values closely track the "average" BBB spreads from this sample of long dated bonds, which supports the AER's conclusion to continue to use Bloomberg

- it is acknowledged that the DRP derived from Bloomberg estimates and the APT bond diverge from late August 2010, with Bloomberg increasing while APT has decreased. This divergence supports the AER's considerations to give less weight to the APT bond as it may not reflect factors affecting bonds of the same credit rating

- whereas the BBB bonds have increased from late August, spreads on the sample of BBB+ rated bonds (which the AER should be considering under the credit rating set in the SORI) have decreased over this time, consistent with the APT bond

- the DNSPs are correct to note that spreads have varied over the AER's time period. However, spreads for the sample of BBB bonds during the period July to August (from which the AER proposes to derive spreads on the APT bond for the purposes of JEN's averaging period) are similar to or otherwise higher than spreads prevailing during JEN's averaging period.

Based on this, the AER believes that it is appropriate to use data from the APT bond to derive the DRP for JEN. For JEN's averaging period the AER will use the first 30 observations of the APT bond yield in conjunction with Bloomberg's fair value estimates, applying a ratio of 25 per cent and 75 per cent respectively, to estimate the DRP.

11.5.3.7 AER conclusion

The credit rating level of BBB+ proposed by the Victorian DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

Given the characteristics of the APT bond the AER considers it important to place some weight on the yield of this bond in assessing the DRP. This is consistent with the Tribunal's comments on the use of averaging and the use of alternative data sources.

The AER has considered the DNSPs' arguments and agrees with the evidence that Bloomberg remains a useful source of data reflective of BBB corporate bond yields with maturity less than seven years.

The AER also acknowledges that the APT bond is only one observation and should not be solely relied upon as a proxy of the benchmark BBB corporate bond.

Accordingly the AER has applied its judgement and will give the APT bond a weighting of 25 per cent and Bloomberg's data series 75 per cent which the AER considers to be reasonable given current circumstances.

The AER has considered the arguments presented by the DNSPs and their consultants and has decided that the appropriate method to extrapolate Bloomberg's 7 year fair value estimates is to use the difference on AAA fair yields from 7 to 10 years. The AER disagrees with the DNSPs that observations of the APT bond from August/ September are not suitable for use in JEN's averaging period which lapsed in May, and has used these observations in calculating JEN's DRP.

11.5.4 Expected Inflation

11.5.4.1 AER draft decision

In the draft decision, the AER stated that a method that is likely to result in the best estimate of inflation over a 10 year period is to apply the RBA's short term inflation forecast-currently extending out to 2 years- and adopt the mid point of its target inflation band beyond that period (2.5 per cent) for the remaining eight years. An implied 10 year forecast is derived by a geometric average of these individual forecasts to estimate the expected inflation.

11.5.4.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs accepted the AER's indicative values, making only minor adjustments in their revised proposal to account for the most recent RBA inflation forecasts.[132]

11.5.4.3 Issues and AER considerations

For this final decision, the AER considers that the most reliable 10 year inflation forecast is a geometric average of the RBA short term forecasts (currently extending out two years) and the mid-point of the RBA's target inflation range for the remaining years in the 10 year period.[133]

Based on this approach and using the latest RBA forecasts as shown in table 11.3, an inflation forecast of 2.57 per cent produces the best estimate for a 10 year period.

Table 11.3 AER conclusion on inflation forecasts (per cent)

	Dec 2011	Dec 2012	Dec 2013	Dec 2014	Dec 2015	Dec 2016	Dec 2017	Dec 2018	Dec 2019	Dec 2020	Geometric average
Forecast inflation	2.75	3.00	2.50a	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.57

Source: RBA, *Statement on monetary policy*, August 2010, p. 56.

132 CitiPower, Revised Regulatory Proposal, p. 353; Powercor, Revised Regulatory Proposal, p. 344; JEN Revised Regulatory Proposal, p. 240; SP AusNet, Revised Regulatory Proposal, p. 308; United Energy, Revised Regulatory Proposal, p. 213.

133 The current RBA forecasts are available at www.rba.gov.au. The current target inflation band is between 2 and 3 per cent per annum; see Treasurer and the Governor of the Reserve Bank of Australia, *Joint statement on the conduct of monetary policy*, 30 September 2010, viewed 27 October 2010, http://www.rba.gov.au/monetary-policy/framework/stmt-conduct-mp-5-30092010.html.

11.5.5 Gearing Level

11.5.5.1 AER draft decision

In the draft decision, the AER adopted the underlying criteria under the SORI which specifies the gearing ratio of 60 per cent.

11.5.5.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs accepted the AER's draft decision and applied the parameter values specified in the SORI for their revised proposals.

11.5.5.3 Submissions

The EUCV noted that the Victorian DNSPs all agreed that the gearing level of 60 per cent was appropriate to each of them in spite that all DNSPs have a gearing level above 60 per cent.[134]

11.5.5.4 Issues and AER considerations

The gearing ratio of 60 per cent proposed by the Victorian DNSPs is as specified in the SORI and consistent with the NER, and is accordingly considered appropriate by the AER.

In accordance with the underlying criteria, the AER considers the proposed level of gearing:

- is supported by the most recent available and reliable empirical evidence, which the AER considers does not support a change to the existing value in the SORI
- generates a forward looking rate of return that is commensurate with prevailing conditions in the market for funds
- together with values, methods and a credit rating for the other parameters, provides a service provider with a reasonable opportunity to recover at least the efficient costs and provides a service provider with effective incentives for efficient investment
- is appropriate having regard to the economic costs and risks of the potential framework in under and over investment.

On this basis, the AER considers the Victorian DNSPs' proposed value achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[135]

In response to EUCV's submission, the AER notes that the gearing level of 60 per cent is set in the SORI and there is currently no persuasive evidence to suggest this is no longer appropriate.

134 EUCV, submission to the AER, August 2010, p. 49
135 NER, cl. 6.5.4(e).

11.5.5.5 AER conclusion

The gearing ratio of 60 per cent proposed by the Victorian DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

11.5.6 Equity Beta

11.5.6.1 AER draft decision

In the draft decision, the AER considered the underlying criteria relating to the NER requirements for the equity beta and adopted the value of 0.8 for the equity beta as specified in the SORI.

11.5.6.2 Victorian DNSP revised regulatory proposals

The Victorian all submitted the equity beta of 0.8 as specified under the SORI and no further issues were raised for this parameter.

11.5.6.3 Submissions

The EUCV noted that the AER's SORI value for equity beta is conservative. The EUCV accepted that the AER has the responsibility to ensure that, if the outcome is biased, the outcome should be biased towards the regulated business. However, the EUCV stressed that this should not entail a large transfer of wealth from customers to the DNSPs. Based on this, the EUCV believed that the AER's current setting of the equity beta as detailed in the final decision for the WACC is too conservative and should be reduced.[136]

11.5.6.4 Issues and AER considerations

In accordance with the underlying criteria, the AER considers the proposed equity beta:

- is supported by the most recent available and reliable empirical evidence, which the AER considers does not support a change to the existing value in the SORI
- generates a forward looking rate of return that is commensurate with prevailing conditions in the market for funds
- together with values, methods and a credit rating for the other parameters, provides a service provider with a reasonable opportunity to recover at least the efficient costs and provides a service provider with effective incentives for efficient investment
- is appropriate having regard to the economic costs and risks of the potential for under and over investment.

On this basis, the AER considers that the proposed value achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[137]

[136] EUCV, *Submission to the AER*, August 2010 p. 50
[137] NER, cl 6.5.4(e).

In response to EUCV's submission, the AER agrees that the equity beta of 0.8 may be considered conservative, however, there is no information currently before the AER to suggest that a lower level is more appropriate than the value in the SORI.

11.5.6.5 AER conclusion

The equity beta of 0.8 proposed by the Victorian DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

11.6 AER conclusion

In accordance with clause 6.12.1(5), the AER's final decision on the rate of return is set out below. The AER's decision on the cost of capital can also be found in the distribution determination documents for CitiPower, Powercor, JEN, SP AusNet and United Energy.

The SORI defines WACC values, methods and the credit rating that must be used in a distribution determination for the purposes of setting a rate of return unless there is persuasive evidence for a departure.

For this draft decision, the AER has determined a nominal vanilla WACC of between 9.40 per cent and 9.95 per cent for the Victorian DNSPs, which is lower than the 10.86 per cent proposed.[138] The difference is due to the AER:

- rejecting the Victorian DNSPs' proposed estimation of the DRP by considering data only from Bloomberg, which according to the AER's analysis would not meet the need for the return on debt to reflect the current cost of borrowings for comparable debt
- updating the nominal risk-free rate to reflect the agreed averaging periods of each DNSP .

Table 11.4 outlines the WACC parameter values for this final decision.

[138] See for example, JEN, *Regulatory proposal*, p. 161.

Table 11.4 AER conclusion on WACC parameters

Parameter	CitiPower	Powercor	JEN	SP AusNet	United Energy
Nominal risk-free rate	5.08%	5.08%	5.65%	5.14%	5.08%
Real risk-free rate	2.44%	2.44%	2.99%	2.50%	2.44%
Expected inflation rate	2.57%	2.57%	2.57%	2.57%	2.57%
Gearing level (debt/equity)	60%	60%	60%	60%	60%
Market risk premium	6.5%	6.5%	6.5%	6.5%	6.5%
Equity beta	0.8	0.8	0.8	0.8	0.8
Debt risk premium	3.74%	3.74%	3.70%	4.05%	3.74%
Nominal pre-tax return on debt	8.81%	8.81%	9.35%	9.19%	8.81
Nominal post-tax return on equity	10.28%	10.28%	10.85%	10.34%	10.28%
Nominal vanilla WACC	**9.40%**	**9.40%**	**9.95%**	**9.65%**	**9.40%**

12 Estimated corporate income tax

This chapter sets out the AER's assessment of the estimated corporate income tax liabilities proposed by CitiPower, Powercor, Jemena Electricity Networks (Victoria) (JEN), SP AusNet and United Energy (the Victorian DNSPs) during the forthcoming regulatory control period. Two key issues discussed in this chapter are the values for the assumed utilisation of imputation credits (gamma) and determination of the tax asset base.

12.1 Regulatory requirements

The AER must make a decision on the estimated costs of corporate income tax to a DNSP in accordance with clause 6.5.3 of the National Electricity Rules (NER). This clause provides the following formula for the calculation of the estimated cost of corporate income tax (ETC_t) of a DNSP for each regulatory year:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

where:

ETIt is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the DNSP, operated the business of the DNSP, such estimate being determined in accordance with the post–tax revenue model;

rt is the expected statutory income tax rate for that regulatory year as

determined by the AER; and

γ is the assumed utilisation of imputation credits.

For these purposes:

(1) the cost of debt must be based on that of a benchmark efficient DNSP, and

(2) the estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient DNSP, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that regulatory year.

The AER's post-tax revenue model (PTRM) calculates a DNSP's tax liability building block in accordance with clause 6.5.3 on the basis of other values inputted by the DNSP and the AER. In particular, the PTRM calculates required revenue for each DNSP, from which tax expenses (opex, interest payments on debt and total tax depreciation for all assets) are deducted to arrive at the DNSP's taxable income. Taxable income is multiplied by the corporate income tax rate, then again by one minus the utilisation of imputation credits (gamma) to arrive at the tax building block for the DNSP.

Clause 11.17.2 also contains Victorian specific transitional requirements for the regulatory control period commencing 1 January 2011:

…

(b) For calculating the estimated cost of corporate income tax, the AER must adopt:

(1) the taxation values of assets carried over from the ESC distribution pricing determination; and

(2) the classification of assets, and the method of classification, adopted for the ESC distribution pricing determination; and

(3) the same method of depreciation as was adopted by the ESC for the ESC distribution pricing determination.

(c) The AER may, however, depart from methods of asset classification or depreciation mentioned in paragraph (b)(2) or (3) to the extent required by changes in the taxation laws or rulings given by the Australian Taxation office.

The formula outlined in clause 6.5.3 above incorporates a value for imputation credits (γ or gamma) in determining the appropriate company tax allowance. Under the Australian imputation tax system, domestic investors receive a credit for tax paid at the company level (an imputation credit)[1] that offsets part or all of their personal income tax liabilities. For eligible shareholders, imputation credits represent a benefit from the investment in addition to any cash dividend or capital gains received.[2] The generally accepted regulatory approach to date in Australia has been to define the value of imputation credits in accordance with the Monkhouse definition.[3] Under this approach, gamma is defined as a product of the 'imputation credit payout ratio' (F – payout ratio) and the 'utilisation rate' (θ – theta).

Gamma has a range of possible values from zero to one. The AER recently determined a value of 0.65 for gamma in its Statement of Regulatory Intent (SORI).[4]

12.1.1 Statement of regulatory intent

Under clause 6.5.4(a) of the NER, the AER conducted a review of the weighted average cost of capital (WACC) which covered certain matters referred to in clauses 6.5.2 and 6.5.3 of the NER, including the value of gamma. On completion of the WACC review the AER issued the SORI regarding these values, methods and credit rating levels.

Under clause 6.5.4(g) of the NER, a distribution determination must be consistent with the relevant SORI unless there is persuasive evidence justifying a departure from a value, method or credit rating level set out in the SORI. Clause 6.5.4(h) of the NER

1 In this chapter the terms imputation credit and franking credit are used interchangeably.

2 Although foreign investors do not pay Australian personal income taxes, they may receive a credit for company tax paid from their home country governments, depending on the inter-country tax arrangements.

3 P. Monkhouse, Adopting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System, Accounting and Finance, Vol. 37(1), 1997, pp. 69–88.

4 AER, *Statement of the revised WACC parameters (distribution), Statement of regulatory intent,* May 2009, p.7

requires that in deciding whether a departure from a value, method or credit rating level set in the SORI is justified, the AER must consider:

> (1) the criteria on which the value, method or credit rating level was set in a SORI (the underlying criteria); and
>
> (2) whether, in light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in a statement inappropriate.

12.2 AER draft decision

With respect to gamma, the AER's draft decision was that the DNSPs did not present persuasive evidence to depart from the value of 0.65 in the SORI. Specifically, the AER made the following conclusions about the arguments and reports submitted to it:

- Payout ratio — the AER agreed with the advice it received from its experts (Mackenzie and Partington and Handley) that the true value of the payout ratio is between 70 and 100 per cent. As per the WACC review, the maintained its assumption of 100 per cent given:
  - the assumption of a 100 per cent payout ratio simplified the framework for estimating gamma, which was appropriate due to the difficulty in reliably estimating the value of retained imputation credits
  - it is consistent with the assumptions of the PTRM
  - it is consistent with the Officer WACC framework, which assumes cash flows to perpetuity.
- Use of tax statistics to estimate theta — the methodology provided by the 2008 Handley and Maheswaran study provides a relevant and reliable estimate of theta in the post 2000 period. The alternative estimate presented by the DNSPs, derived by Synergies, is unreliable as it was produced by a method that suffers from numerous flaws.
- Use of dividend drop off studies to estimate theta — the AER maintained its reliance on the estimate derived from the Beggs and Skeels study, and continued to consider the alternative Strategic Finance Group (SFG) study was unreliable, in spite of various revisions to the study since the WACC review. In addition to some miscellaneous issues with SFG's results, and with dividend drop off studies generally, the AER's main issues with SFG's study were:
  - SFG's use of Cook's D statistic to exclude the most influential observations from its dataset was a blunt and ad hoc approach to generating a "clean" dataset, whose impact on parameter estimates was difficult to determine. This contrasts to the superior ex ante filtering method employed by Beggs and Skeels
  - the concerns with SFG's data set were reinforced by the analysis of Dr John Field (presented on behalf of the DNSPs) who examined 150 randomly selected observations in SFG's dataset, and identified 16 observations (or over

10 per cent) which should have been excluded. SFG's response to this finding (i.e. to simply exclude these observations from the dataset of over 3000 observations) was inadequate and dismissive of the AER's fundamental concerns.

In calculating the tax liability building block, the AER amended the DNSPs' tax roll forward calculations to reflect changes in tax legislation affecting the depreciation of assets held on or after 10 May 2006.

The AER also determined a gradual reduction in the corporate income tax rate over the forthcoming regulatory control period to reflect announcements made by the Commonwealth Government in May 2010 arising out of the Henry Review. Specifically, the AER determined the corporate tax rate would reduce from the current 30 per cent to 29 per cent for the 2013–14 financial year and to 28 per cent from the 2014–15 financial year.

The AER's draft decision corporate income tax building block for each DNSP is listed in table 12.1.

Table 12.1 AER draft decision on corporate income tax liability ($'m, nominal)

DNSP	2011	2012	2013	2014	2015
CitiPower	6.0	6.3	6.6	6.6	6.8
Powercor	7.7	8.6	9.2	9.8	10.6
JEN	2.3	2.8	3.3	3.7	3.0
SP AusNet	8.2	3.5	4.4	4.3	3.8
United Energy	4.8	5.6	6.7	7.2	7.8

12.3 Victorian DNSP revised regulatory proposals

All Victorian DNSPs have continued to propose a departure from the 0.65 value of gamma specified in the SORI. The following table depicts the values for gamma that Victorian DNSPs submitted in their revised regulatory proposals.

Table 12.2 Revised proposal gamma values

DNSP	Gamma value
CitiPower	0.5
Powercor	0.5
JEN	0.2
SP AusNet	0.5
United Energy	0.2

Source: Victorian DNSPs' revised regulatory proposals

The Victorian DNSPs have argued for relatively lower values of theta and the payout ratio than were adopted in the Victorian draft distribution determination. Specifically, the Victorian DNSPs have:

- continued to cite empirical evidence from tax statistics used in existing reports from Feros, Hathaway and Officer (2004), NERA and Synergies in support of a payout ratio less than 100 per cent. This position is supported further with the inclusion of a report prepared by Dr Neville Hathaway which investigates how tax statistics should be interpreted to estimate the payout ratio.

- provided evidence from Hathaway that contends a payout ratio of less than one is not inconsistent with the Officer CAPM framework. Furthermore, that Professor Officer has not made any statements regarding the payout ratio in relation to the Officer CAPM framework. The Victorian DNSPs also contend that the AER's characterisation of the PTRM as a perpetuity model is inconsistent with the fact that no cash flows in the PTRM are perpetuities

- argued retained credits are likely to be heavily discounted, on the basis that there are significant impediments that prevent the payout of retained credits. As such, this is further evidence that the payout ratio should be closer to 70 per cent. The Victorian DNSPs note that this is consistent with the advice provided by the AER's consultants, Associate Professor John Handley and Professors McKenzie and Partington

- relied on reports prepared by Hathaway that challenged the Handley and Maheswaran 2008 tax study relied on by the AER to estimate the value of theta. The Victorian DNSPs make the further point that tax studies in general should not be used to estimate theta

- dismissed the AER's concerns in relation to SFG's dividend drop-off study and argued for SFG's study to be considered by the AER to estimate the value of theta

- asserted that the AER has made inconsistent assumptions in estimating the grossed-up value of the MRP and the value of imputation credits as calculated in Beggs and Skeel's dividend drop-off study

- argued that taking an average of the results from tax and dividend drop-off studies to estimate a value of theta is methodologically flawed.

SP AusNet, CitiPower and Powercor consider the AER should take a balanced approach when recognising these arguments and adopt a gamma value of 0.5.[5] United Energy and JEN recommend the AER adopt a gamma of 0.2, which is based on a 70 per cent payout ratio and a theta value of 0.23.[6]

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5 CitiPower, *Revised regulatory proposal 2011 to 2015*, 21 July 2010, p. 368; Powercor, *Revised regulatory proposal 2011 to 2015*, 21 July 2010, p. 359; SP AusNet, *Electricity Distribution Price Review Revised regulatory proposal* , July 2010, p. 331.

6 JEN, *Revised regulatory proposal 2011–15*, 20 July 2010, p. 267; United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 211.

The DNSPs accepted the AER's draft decision with respect to tax depreciation calculations. SP AusNet, United Energy and JEN rejected the AER's corporate tax rate, while this was accepted by CitiPower and Powercor who proposed corresponding operational expenditure adjustments arising out of the Government's tax policy announcements. The DNSPs' revised proposal tax liabilities are reporting in table 11.3

Table 12.3 DNSP revised proposals corporate income tax liability ($'m, nominal)

DNSP	2011	2012	2013	2014	2015
CitiPower	4.2	4.6	5.5	5.9	6.9
Powercor	3.9	4.8	6.0	7.2	9.0
JEN	2.0	2.7	3.7	5.4	5.4
SP AusNet	6.0	0.0	0.0	0.0	0.0
United Energy	11.0	12.8	16.2	21.0	25.6

Source: DNSP PTRMs.

12.4 Submissions

EnergyAustralia noted:

> To the extent that the AER still does not depart from existing parameters, we see significant benefit in understanding the difference between the evidence that persuaded it to depart from previously adopted parameters in its review of WACC parameters and the new evidence which is insufficient to persuade it to depart from these new parameters.[7]

In respect of estimating gamma, the Energy Users Coalition of Victoria (EUCV) noted that the Victorian DNSPs' revised proposals submitted the same information as ETSA Utilities in its application to the AER.[8] Additionally, the EUCV considered that the WACC parameters cannot be estimated in isolation and mechanistically developed. Furthermore, the EUCV states:

> All of the elements bear some relation to the others used in the development of the final value for WACC. To isolate one or two elements and accept the others does not recognise the inter-dependence between the elements.[9]

The EUCV asserted that there can be no adequate additional information that would make a significant difference to the AER's WACC review performed in May 2009. Finally, the EUCV considers that should WACC parameters change as a result of Victorian DNSPs' revised proposals, other WACC parameters should also be re-estimated that might also have varied as a result of the GFC.[10]

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7 EnergyAustralia, *Energy Australia submission on AER draft regulatory determination for Victorian distributors*, 19 August, p. 15.

8 Energy Users Coalition of Victoria, *Submission to the AER - 2010 AER review of Victorian Electricity DBs, EUCV response to AER Draft Decision*, August 2010, p. 73.

9 EUCV, *Submission to the AER*, 19 August, p. 74.

10 ibid.

The DNSPs submitted a study by Professors Neil Diamond and Robert Brooks in support of their revised proposals. This study analysed the effects of multicollinearity on SFG's dividend drop-off study, using variance inflation factors and Eigan-value decomposition models. Diamond and Brooks made the following comments on variance inflation factors:

> The usual criterion for concern is a variation inflation factor of 10, (see, for example, Bowerman and O'connell, 1990, p. 477.), which suggests that multicollinearity is not a problem. None of the variance inflation factors in the data set are close to this level. The square root of the variance inflation factor shows how much the confidence interval for a regression coefficient has increased because of any multicollinearity in the data.[11]

Additionally, Diamond and Brooks used the Eigen value decomposition which uses a variance-covariance matrix to conclude that the linear combination of cash drop off and franking credit drop-off values for the period 1 July 2000 to 30 September 2006 have the lowest standard error estimates, and conclude that multicollinearity is not a significant issue in SFG's model. Diamond and Brooks concluded:

> The standard errors of the parameter estimates for the cash dividend and for the franking credit, over the most recent time period (from 1st July 2000 to 30th September 2006) are only marginally higher than they would be in the absence of multicollinearity.[12]

12.5 Consultant review

To assist it in responding to the DNSPs' revised proposals, the AER engaged Associate Professor John Handley who primarily responded to the reports of Hathaway and SFG, whose arguments were adopted in the DNSPs' revised proposals. Handley also reiterated elements of advice provided to the AER previously, including during the WACC review, when responding to the DNSPs' arguments. Handley's main points were:

- The DNSPs' proposed 70 per cent payout ratio is an extreme assumption as retained credits must have value to investors[13]

- The arguments levelled at the Handley and Maheswaran 2008 tax study are based on a misreading of the study, are unfounded or have no implications for the estimation of theta.[14]

12.6 Issues and AER Considerations

The AER notes that on 13 October 2010 the Australian Competition Tribunal handed down its reasons for decision regarding the AER's South Australia and Queensland distribution determinations. The Tribunal found errors by the AER in its treatment of the imputation credit distribution ratio and the utilisation rate. However, the Tribunal did not make a determination on the value of gamma to be applied for the South

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11 Diamond and Brooks, *Determining the value of imputation credits: Multicollinearity and reproducability issues*, August 2010, p. 7.
12 ibid., pp. 10–11.
13 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 4.
14 ibid., p. 21.

Australia and Queensland distribution determinations. The Tribunal seeks a report from the AER in relation to various aspects of the determination of gamma.

The further work as part of the Tribunal proceedings is not available for the Victorian distribution determination. The AER has made this final decision in relation to gamma for the Victorian DNSPs on the basis of all relevant information currently before it.

12.6.1 Corporate tax rate and tax depreciation

12.6.1.1 AER draft decision

The draft decision considered that the Victorian DNSPs' proposals largely complied with the transitional rules in adopting the same tax depreciation methodology and values as used by the Essential Services Commission of Victoria (ESCV).[15] The AER determined that changes to Division 40 of the Income Tax Assessment Act 1997 (ITAA 1997), which set out new depreciation rates for assets held on or after 10 May 2006, should have been taken into account by the Victorian DNSPs under clause 11.17.2(c) of the NER and amended the Victorian DNSPs’ tax roll forward calculations to reflect this.[16]

The AER determined that the proposed changes to the corporate taxation arrangements announced by the Commonwealth Government on 11 May 2010 should be reflected in the statutory corporate tax rate under clause 6.5.3 of the NER. The Government's proposed reductions in the corporate tax rate were applied in the AER’s modelling of the DNSPs’ tax building block.[17]

12.6.1.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs all accepted the AER draft decision amendments to the tax roll forward calculations to account for the amendments to Division 40 of the ITAA 1997 and incorporated them into their revised proposals.

SP AusNet, JEN and United Energy considered that the proposed changes to the corporate taxation arrangements announced by the Commonwealth Government on 11 May 2010 should not be reflected in the expected statutory corporate income tax rate. SP AusNet and United Energy noted that the corporate tax policy had been changed significantly since the AER published its draft decision. They further noted that the proposed changes would not be introduced into parliament until after the next federal election and would be dependent on the election result.[18] SP AusNet considered that the inclusion of the proposed corporate tax changes was speculative and unjustifiable, given the uncertainty surrounding the passing of enabling legislation to give effect to the changes.[19] JEN considered that the AER was incorrect to use recently announced Commonwealth Government tax policy to estimate the corporate income tax rate because it does not reflect current Australian tax law and is subject to

15 AER, *draft decision*, June 2010, p. 552.
16 ibid., p. 554.
17 ibid., p. 555.
18 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 212; SP AusNet, *Electricity Distribution Price Review, Revised Regulatory Proposal*, July 2010, p. 342–343.
19 SP AusNet, *Revised Regulatory Proposal*, p. 342–343.

change.[20] SP AusNet, JEN and United Energy further considered that it was unnecessary for the AER to make any assumptions regarding the proposed changes to the corporate income tax rate, as the tax change event pass through mechanism in the NER could be used to deal with changes in tax during a regulatory control period.[21]

United Energy considered that the AER's decision to include proposed changes to corporate tax rates was inconsistent with the AER's treatment of possible legislative or regulatory change in other areas of the draft decision, in particular the expenditure implications arising from the Victorian Bushfire Royal Commission and changes to safety legislation.[22]

CitiPower and Powercor adopted the AER's draft decision amendments with adjustments to reflect the changes to the tax policy that occurred after the draft decision was published. They noted that other tax changes were announced by the Commonwealth Government at the same time, in particular the superannuation guarantee rate, and argued that for consistency the AER should also allow an opex step change to address this.[23]

12.6.1.3 Submissions

The Victorian Council of Social Service considered that the proposed business tax changes should be dealt with as a tax change event pass through rather than factored into the current decision, as the proposed changes to the tax are not yet clear.[24]

12.6.1.4 AER considerations

The AER accepts the Victorian DNSPs' adopted changes to their tax depreciation calculations to account for the amendments to Division 40 of the ITTA 1997. The AER requires no further amendments in this regard.

The AER notes that the Commonwealth Government's announced changes to corporate taxation arrangements have undergone a number of changes since the draft decision was published. Further, the proposed reduction in the corporate tax rate from 30 to 29 per cent from 2013–14 is reliant on the introduction of the Minerals Resource Rent Tax (MRRT), as the proceeds from this are to be used to fund the corporate tax rate reduction. The introduction of the MRRT is uncertain as there is significant opposition to it.

The Federal Treasurer, Wayne Swan, said that the Government intends to push forward with the introduction of the MRRT, however it may be discussed at the tax summit in early 2011. The MRRT is currently the subject of a consultation and review process led by former BHP chairman Don Argus, which will consult on the design and implementation of the revised resource tax arrangements. The Commonwealth Government's indicative timeline suggests that the enabling legislation will be

20 JEN, *Revised Regulatory Proposal*, p. 269–270.
21 SP AusNet, *Revised Regulatory Proposal*, July 2010, p.343.
22 United Energy, *Revised regulatory proposal*, p. 212.
23 Powercor, *Revised Regulatory Proposal*, July 2010, pp. 360–361.
24 VCOSS, *Submission to AER Distribution Price Review Draft Determination*, August 2010, p. 3.

introduced to parliament in the latter half of 2011 with the aim of implementing the legislation on 1 July 2012.[25]

It is likely that further changes will be made to the tax reform package in order to have the enabling legislation passed through parliament, and as a result, it is uncertain whether or when the proposed reduction to the corporate tax rate will be introduced. In light of this, the AER considers that potential changes to the corporate tax rate cannot reasonably be reflected in the expected statutory corporate income tax rate for the forthcoming regulatory control period.

Powercor's and CitiPower's revised proposals considered that the AER must also allow an opex step change to address the changes to the superannuation guarantee rate that were announced as part of the tax reform policy for consistency with its approach to the company tax rate changes. The AER note that the proposed changes to the superannuation scheme are also to be funded by the proceeds from the MRRT, therefore the proposed superannuation changes are subject to the same uncertainties as discussed for the proposed changes to the corporate tax rate. In order to maintain consistency with its approach to the company tax rate changes, the AER considers that it would be inappropriate to allow an opex step change to address the proposed changes to the superannuation guarantee rate, as the implementation of the policy is too uncertain.

'Tax change event' pass through mechanism

The AER considered in its draft decision that the NER pass through events would not include a change in the corporate income tax rate, as the tax change event is restricted to changes in a 'relevant tax' which explicitly excludes 'income tax'. The AER draft decision also rejected United Energy's submission in its initial regulatory proposal to include a 'change in corporate income tax' event as a nominated pass through event for the distribution determination. As the NER explicitly excludes corporate income tax changes from the definition of a tax change event, the AER draft decision considered that it would be inappropriate to accept the additional pass through event.[26]

SP AusNet's, JEN's and United Energy's revised regulatory proposals and VCOSS's submission suggested that it would be appropriate for the AER to use the pass through procedures of the NER to deal with any changes to the corporate tax rate during the forthcoming regulatory control period rather than accounting for it in the tax roll forward calculations.

The AER affirms its draft decision conclusion that changes to the corporate income tax rate are explicitly excluded from the definition of a tax change event in Chapter 10 of the NER.[27] In light of this, the AER cannot utilise the pass through mechanisms of the NER to manage a change in costs arising out of a change to the corporate income tax rate.

12.6.1.5 AER considerations

The AER has accepted the DNSPs' revised proposals in relation to tax depreciation calculations as they are in accordance with clause 11.17.2 of the NER. The AER has

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25 http://www.futuretax.gov.au/documents/attachments/factsheet_resource_taxation.pdf.
26 AER, *draft decision*, June 2010, p. 710.
27 See definitions of 'tax change event' and 'relevant tax' in chapter 10 of the NER.

determined that the current corporate income tax rate of 30 per cent will continue to apply for the forthcoming regulatory control period. To the extent that any reductions in the corporate tax rate eventuate in this time, the DNSPs will enjoy a small windfall gain.

12.6.2 Estimating the payout ratio

12.6.2.1 Statement of regulatory intent

In the WACC review, the AER considered that a reasonable estimate of the annual payout ratio is the market average of 71 per cent provided by Hathaway and Officer.[28] In effect, this means 71 per cent of all imputation credits, created in a given year, are assumed to be distributed to shareholders in that same year. Once distributed, shareholders are assumed to value these credits at between 0 and 100 per cent of their face value, which reflects the utilisation rate.

However, there was disagreement on the value of retained credits and what happens to the imputation credits which are not distributed immediately. Based on detailed consideration of all the available information, the AER's conclusions on the overall payout ratio in the WACC review were:

- there was clear merit in the recommendation put forward by Handley to adopt a payout ratio of 100 per cent, in particular with respect to simplicity in the framework, and the strong theoretical grounds that a full distribution of imputation credits is appropriate for valuation purposes and consistent with the Officer WACC framework

- in accordance with the framework proposed by the National Economic Research Associates (NERA), based on a reasonable set of assumptions[29] the AER considered that a reasonable estimate of the payout ratio using the analysis suggested by NERA is between 91 and 98 per cent.[30]

On the basis of these considerations the AER concluded the issue of time value loss associated with retained credits was not significant, such that the adoption of an estimate for the payout ratio of 100 per cent was not unreasonable. A payout ratio of 100 per cent was also consistent with the influential Officer WACC framework and the modelling assumptions in the AER's PTRM.

12.6.2.2 AER draft decision

The draft decision maintained the approach adopted during the WACC review that a 100 per cent payout ratio was appropriate. The AER's key conclusions were:

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[28] AER, *Final decision, WACC parameters*, May 2009, p. 414; and N. Hathaway and R. R. Officer, *The value of imputation tax credits*, Report, Capital Research Pty Ltd, November 2004. Note that this payout ratio has been obtained using tax statistics rather than dividend payout ratios from annual reports (which are measured differently to dividends in tax statistics).

[29] Assumptions included that the discount rate was somewhere between the risk-free rate and the cost of equity, the retention period for imputation credits ranged from one to five years and a payout ratio of 71 per cent. AER, Final decision, WACC parameters, 1 May 2009, pp. 418–419.

[30] AER, *Final decision, WACC parameters,* May 2009, pp. 419–420.

- it agreed with the advice it received from Handley and Mackenzie and Partington and noted the actual payout ratio is likely to be between 70 per cent and 100 per cent

- the assumption of a 100 per cent payout ratio simplifies the framework for estimating gamma, which is appropriate due to the difficulty in reliably estimating the value of retained imputation credits

- a 100 per cent payout ratio is consistent with the PTRM, which assumes cash flows to perpetuity and thus the full distribution of cash flows at the end of each period

- a 100 per cent payout ratio is consistent with the Officer WACC framework, which clearly assumes cash flows to perpetuity.[31]

12.6.2.3 Victorian DNSP revised regulatory proposals

The Victorian DNSP's submitted the payout ratio should be less than 100 per cent and that empirical evidence supports a payout ratio of around 70 per cent.[32] The DNSPs' arguments are most clearly summarised by JEN:

> - there is no evidence that undistributed credits will eventually be distributed as the AER claims
>
> - undistributed credits should have a substantially lower value than distributed credits
>
> - the Officer framework does not require a payout ratio of one
>
> - the AER’s own expert advisors agree that the actual payout ratio is less than one
>
> - the AER’s imputation credit payout ratio of one is not backed by empirical evidence; rather, the weight of empirical evidence supports a payout ratio of 70 per cent.[33]

To support their arguments, the Victorian DNSPs submitted and referred to many reports considered in previous decisions by the AER, including from Professor Officer, NERA and tax lawyer Peter Feros, as well as new reports from Hathaway and SFG.

Hathaway's main conclusions are:

- the AER's assumption that 100 per cent of credits will be distributed over a five year period is contrary to all the evidence, and its explanation of how companies would achieve this is weak

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31 AER, *draft decision*, June 2010, p. 537.

32 Citipower, *Revised regulatory proposal*, pp. 361–362; Powercor, *Revised regulatory proposal*, pp. 350–352; SP AusNet, *Revised regulatory proposal,* pp. 331–333; United Energy, *Revised regulatory proposal*, pp. 201–203; JEN, *Revised regulatory proposal*, pp. 250–255.

33 JEN, *Revised regulatory proposal*, p. 250.

- regardless of the value ascribed to retained credits, for all practical purposes the probability of investors ever realising that value is zero
- calling the franking account balance (FAB) “retained credits” is misleading because
  - it implies it is readily accessible, whereas it can only be accessed along with franked dividends
  - retained earnings are kept by companies in order to finance their growth, which as often been invested and is not readily available as dividends
  - it is no more than a book entry of how much tax has been paid as net company tax to the Federal Government
- there is no reason why retained credits could not grow in perpetuity, and to suggest shareholders will not tolerate this is inconsistent with the current situation of large franking account balances
- the AER is wrong to assert that the WACC models must assume a 100 per cent payout.[34]

SFG's report echoes most of these arguments, and makes a few additional points:

- The AER is inconsistent to adopt the Officer framework and assume all credits are paid out in the same period, and to also assume that retained credits exist but have the same value as immediately distributed credits.
- The AER's suggestion that it must assume a 100 per cent payout ratio to be consistent with the Officer framework overlooks the inconsistencies between this framework and the AER's PTRM, and calculation of the MRP, both of which do not reflect perpetuity assumptions.
- The methods by which companies could distribute retained credits, as identified by the AER, are already reflected in the 71 per cent ratio. The AER has not addressed an argument in SFG's December 2009 report which shows that firms can only distribute retained credits if they (on average) distribute more than 100 per cent of their earnings as dividends, which is logically impossible.
- In assuming that retained credits are just as valuable as distributed credits, the AER has ignored advice from Mackenzie and Partington that capex financed from retained earnings prevents/ delays the distribution of those credits, thus retained earnings become a more expensive equity finance.[35]

12.6.2.4 Consultant review

Handley pointed out that the Officer framework for estimating gamma, which the AER has effectively adopted when assuming a full payout of credits, is a theoretical simplification which only applies in a perpetuity setting. Handley also acknowledges

34 Hathaway, *Practical issues in the AER Draft Determination*, July 2010, p. 5.
35 SFG, *Issues relating to the estimation of gamma*, July 2010, p. 3.

that the alternative Monkhouse approach provides a closer approximation to reality; however, it requires further estimation of the value of a retained credit as per the psi term in the following formula:[36]

$$\gamma = F \times \theta + (1 - F) \times \psi$$

Handley characterises the DNSPs' arguments as proposing a modified version of the Monkhouse approach, where psi is assumed to be zero and F is equal to 70 per cent. While Handley acknowledges that there are theoretical grounds to value retained credits less than distributed credits, he considers that it is not necessarily the case that adopting a more complicated or realistic approach than the Officer framework will deliver a better estimate of gamma, given inherent imprecision in the value of theta.[37]

Handley also acknowledges that evidence shows that a net 30 per cent of credits were not distributed over 1996 to 2008, however disagrees with the DNSPs' interpretation of this evidence that retained credits will never be paid out, which he considers to be an extreme assumption. Handley points out that this implies that the current balance of $170 billion[38] in retained credits are worthless, which is a "huge amount".[39] Handley notes that there is no empirical evidence concerning the value of retained credits, however, suggests that the market value of credits would be reflected in capital gains (although there is currently no method to separately identify this from other factors), and also provides the example of Microsoft which only began paying dividends to shareholders after 27 years of operation.[40] This example highlighted that the DNSPs should not presume observations over the period identified by Hathaway will continue indefinitely into the future.[41]

Handley also responds to arguments presented by the DNSPs and their consultants regarding the AER's apparent reliance on the Officer framework's perpetuity assumption when setting a payout ratio of 100 per cent. Handley points out that the AER's preference for the Officer model is its simplicity, and that the Monkhouse approach already provides for non perpetual cash flows (making the model presented in Hathaway's report redundant).[42]

12.6.2.5 Issues and AER considerations

Empirical estimates of the payout ratio

The overall payout ratio estimate from Hathaway and Officer (2004) for the period 1988 to 2002 is 71 per cent. This is calculated using the total value of imputation credits created and the total value of franking account balances up to 2002.

The 68 per cent payout ratio estimate from NERA is not materially different from the 71 per cent estimate from Hathaway and Officer. However, AER notes that NERA does not estimate the payout ratio in the same manner as Hathaway and Officer (2004). NERA estimates an average annual payout ratio for the period 1996–97 to

[36] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, pp. 3–4.
[37] ibid., pp. 5–6.
[38] Australian Taxation Office, *Taxation Statistics 2007–2008*, 2010, Company tax table 6.
[39] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 8.
[40] ibid., pp. 9–10.
[41] ibid., p. 9.
[42] ibid., p. 12.

2006–07 by estimating the number of imputation credits created in each year and the credits distributed each year.[43]

Hathaway provides analysis showing the annual changes in the aggregate value of franking account balances in his report for the Victorian DNSPs. The analysis shows that the annual payout ratio in any one year can vary from the overall estimate of the payout ratio over a longer period. In particular, the years 2001 and 2002 were significantly different from the long term average:

- In 2001 the increase in franking account balances was significant, resulting in a payout ratio for that year alone being significantly lower than 70 per cent

- In 2002 there was a decrease in franking account balances, resulting in a payout for that year of greater than 100 per cent.

These years do not significantly affect the overall payout ratio, which Hathaway estimates to be 69 per cent for data up to 2008 using the same method as Hathaway and Officer (2004).[44] This estimate shows that the overall payout ratio has remained around 70 per cent and is calculated from known data sourced from franking account balances.[45]

The AER accepts that these estimates reflect total or average observations over the various time periods considered, whereas during the WACC review the AER interpreted these values to be the amount of all imputation credits created in a given year to be distributed to shareholders in that same year. The correct interpretation of these values means that the proportion of credits in franking account balances (which are subjected to time value decay) is not simply 30 per cent of total credits generated every year and that the 70 per cent value includes franking credits generated in a year and paid out in the same year, as well as franking credit generated in previous years. That is, there is no constant or predictable relationship between the time a credit is generated and when it is paid out.

The value of retained imputation credits

The AER notes that the overall payout ratio of 71 per cent as estimated by Hathaway and Officer (2004) and more recently as 69 per cent by Hathaway is around 70 per cent. However, the AER does not consider that this supports a conclusion that retained imputation credits will never be distributed. This is also noted by Hathaway, who states that 13 years is not "forever" so empirical evidence cannot confirm or deny the proposition that retained imputation credits will be distributed in the future.[46]

Handley has advised that the period referred to by Hathaway is a very small sample (in a statistical sense) to draw a definite conclusion about future distribution activity. Furthermore to assume retained imputation credits would never be distributed would

43 The AER also notes that the NERA report shows that the ratio of credits distributed to credits created in a year varies from 35 per cent (2002-03) to 89 per cent (2000-01) in the period 1996-97 to 2006-07.

44 Hathaway, *Imputation credit redemption: ATO data 1988-2008*, July 2010, p. 7.

45 Hathaway, *Practical issues in the AER draft determination*, July 2010, p. 7.

46 ibid.

be to assume that approximately 170 billion dollars in retained imputation credits will never be paid out and are essentially without value.[47]

There has been increasing investor speculation about the extraction of value from the large franking account balances through the distribution of retained imputation credits.[48] Woolworths also recently conducted a significant off-market buyback that enabled it to distribute 260 million dollars from its franking account balance (equivalent to approximately 20 per cent of its accumulated franking account balances).[49] The AER acknowledges that the data presented by the DNSPs reflect actions such as off-market buy backs, and also agrees with the DNSPs that retained credits, once distributed, would be valued less than credits immediately distributed due to time value loss. However, the speculation about the growing value of retained credits, and the significant distribution of credits by Woolworths, reflect rational investor expectations that businesses will deliver this value to shareholders. The total amount of credits distributed exceed the amount generated in 2002, which provides an example where mechanisms such as off market buy backs could be used to distribute retained credits faster than they are generated, and is counter to SFG's conclusion that this outcome is a "logical impossibility". [50] Also, while 2002 was a specific case, it illustrates that series of retained franking credits from past years cannot be used to confirm or deny that retained credits will be distributed, as recognised by Hathaway.[51]

The AER acknowledges that it is unlikely that there would be a significant payout of retained imputation credits during the forthcoming regulatory control period. However, this does not mean that retained imputation credits do not have value as they may be distributed in future periods. Furthermore, as noted by Handley, the value of retained credits may already be present in the market value of those companies with significant franking account balances.[52]

Finally, the DNSPs briefly remark that the AER has chosen to ignore Mr Feros' analysis, which demonstrates there are a number of legal and regulatory impediments to distributing retained credits.[53] However, the AER has previously commented on this analysis, in particular that it identifies policy intentions regarding the wastage of credits after they are distributed (thus relates to the estimation of theta rather than the payout ratio) and merely speculates about possible actions of legislators that could affect the distribution of credits in the future.[54]

Consistency with the Officer WACC framework

Officer 2009 states the AER's view is that all dividends are eventually distributed.[55] The AER notes that this did not form the basis for it adopting a payout ratio of 100 per cent in the WACC review. Rather, the AER simply noted that the Officer WACC

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47 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 8.

48 Australian Financial Review, *Chase for franking credits heats up*, 13 September 2010, p. 24.

49 Australian Financial Review, *Woolworths splashes its franking cash*, 20 September 2010, p. 20.

50 SFG, *Issues relating to the estimation of gamma*, July 2010, p. 12.

51 Hathaway, *Practical issues in the AER draft determination*, July 2010, p. 7.

52 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 9.

53 See for example, United Energy, *Revised regulatory proposal*, p. 202.

54 See for example, *AER South Australia Draft distribution determination 2010–11 to 2014–15*, November 2009, p. 258.

55 Officer, *Estimating the distribution rate of imputation tax credits: Questions raised by ETSA's advisors*, June 2009, p.3.

framework does assume full distribution of dividends in a perpetuity setting. The AER considered that full distribution of dividends was a reasonable simplifying assumption and consistent with this assumption a 100 per cent payout ratio for imputation credits should be assumed.

The Officer WACC framework does not assume a constant dividend distribution rate, with a constant retention of earnings. If this were the case a range of additional factors would need to be taken into account such as the differential effects of capital gains tax versus tax on dividend income and whether there is systematic growth in the company's assets due to systematic retention of earnings.

Handley points out that alternative frameworks such as Lally and Van Zijl (2002) provide a method for calculating the cost of capital incorporating differential tax rates for capital gains and dividend income. However, this is a more complex framework and the AER notes that consistency with the Officer WACC framework is preferred due to its simplicity. This is consistent with Handley's advice.

The AER notes that the DNSPs' proposals (i.e. to adopt a payout ratio of 70 per cent) also reflect a simplified approach, however the AER does not regard this as correct given that there are strong theoretical grounds to support the assumption that retained credits have value. The AER accepts, however, that the appropriate interpretation of empirical evidence means that the assumption of 100 per cent is no longer sustainable.

Other conceptual issues

The AER acknowledges that it was incorrect in previously stating that the 100 per cent payout assumption was "consistent with the PTRM, which assumes cash flows to perpetuity and that cash flows are fully distributed at the end of each period."[56] This was a misquote of the AER's statement in the WACC review, that the consistency lay with the PTRM as it "explicitly assumes a full distribution of free cash flows".[57] That is, the PTRM's calculations are based on returns to equity holders (along with imputation credits) being completely paid out in each year rather than being retained. The significance of this point is that recognising the value of retained credits (noting that this is not currently proposed by the DNSPs) would bring additional complications in the calculation of gamma but also more detailed and complicated calculations in the PTRM. Movements towards additional complexity can lead to spurious accuracy and replace assumptions that have been made interdependently in order to produce offsetting impacts on DNSPs' overall revenue requirements, as recognised by Mackenzie and Partington:

> The AER chose not to discount the value of the undistributed credits as a simplifying assumption. We understand that this particular assumption is balanced by other aspects of the determination where not discounting for the time value of money favours the DNSPs.[58]

In this context, SFG also highlight a further conceptual issue raised by Mackenzie and Partington not addressed by the AER in the draft decision, in relation to the implications of assuming a 100 per cent payout ratio on the overall cost of capital:

56 AER, *draft decision*, June 2010, p. 535.

57 AER, *Final decision, WACC parameters,* May 2009, p. 420.

58 McKenzie and Partington, *Report to the AER: Evidence and submissions on Gamma*, March 2010, p. 26.

> One line of argument to support the full valuation of undistributed franking credits is to make the usual assumption of finance theory that the objective of management is to maximise shareholder wealth. If so, the minimum criteria for the retention of credits is that their retention is value neutral. In other words, no value should be lost by the retention of franking credits and so there is a case for valuing them fully. However, this line of argument implies either a higher cost base, or a higher cost of capital, for investments financed from retained earnings that could otherwise be distributed as franked dividends.[59]

The AER acknowledges that if retained credits were fully valued by shareholders then this may imply differential costs of equity finance, however the AER's PTRM does not reflect this level of detail, and it has not been argued that the inclusion of such detail, including assumptions around retained credits, in the cash-flow modelling would yield any benefits.

12.6.2.6 AER conclusion

Based on the above considerations, the AER concludes that:

- consistent with previous decisions, the estimated value of the payout ratio, for the purposes of the "traditional" approach to calculating gamma, is within a range of 70 to 100 per cent

- the AER has previously incorrectly interpreted empirical evidence to mean that the annual payout ratio was approximately 70 per cent. When correctly interpreted, this value reflects the average payout ratio, with the annual payout ratio likely to be below this value.

- this interpretation means that the proportion of retained credits subject to time value loss is greater than previously conceived. However, the AER disagrees with the DNSPs' conclusion from this evidence that retained credits will never be paid out and thus have no value.

The AER now accepts that appropriate interpretation of empirical evidence means that the payout ratio should be less than the value of 100% adopted in the SORI and in the Victorian draft decision. Therefore, under clause 6.5.4(g) of the NER, for the Victorian distribution determinations, there is persuasive evidence that justifies a departure from the gamma value set in the SORI in respect of the payout ratio.

The AER considers that where there is persuasive evidence for departing from the gamma value set in the SORI, the gamma value should be departed from only to the extent that the persuasive evidence needs to be addressed. The term used in clauses 6.5.4(g) and (h) of the NER is "departure from" not "rejection of". The AER considers that where it is established that there is persuasive evidence for departing from the gamma value set in the SORI in relation to one aspect (payout ratio), the persuasive evidence test still applies to the question of whether another aspect of gamma (theta) should also be changed from the SORI.

The AER considers that this interpretation of clauses 6.5.4(g), (h) and (i) of the NER is consistent with the intent of NER that the WACC parameters will be certain and

59 ibid., pp. 26–27

predictable in the distribution determination processes during the currency of each SORI unless a departure can be justified by persuasive evidence. This goes some way to address the submission of Energy Australia who required some guidance on how and why the AER would depart from parameter stated in the SORI.

12.6.3 Use of dividend drop-off studies to estimate theta

In its reasons for decision on 13 October 2010 regarding the South Australia and Queensland distribution determinations, the Tribunal found in relation to dividend drop-off studies: [60]

- The AER made no error in refusing to substitute the SFG study results for those of Beggs and Skeels (2006).
- The Tribunal does not consider that at this stage it is appropriate to accord the SFG study equal weight with Beggs and Skeels (2006) and average the results from the two studies.
- The Tribunal considers that the results of Beggs and Skeels (2006) must be regarded with something approaching equal caution to that applying to the SFG study.
- The Tribunal seeks a report on theta from the AER which, if possible, provides results from a newly-commissioned dividend drop-off study that is "state of the art". The Tribunal proposes to direct the AER to seek a re-estimation by SFG of the parameters without the constraint that the study replicates the Beggs and Skeels (2006) study.[61]
- Given the timing considerations, the further work as part of the Tribunal proceedings is not available for the Victorian distribution determination. The AER's consideration of dividend drop-off studies in the Victorian distribution determination is based on the information currently available before it.

12.6.3.1 Statement of regulatory intent

During the WACC review, the AER considered two main reports concerning the value of theta inferred from market prices:

- The impact of franking credits on the Cost of Capital of Australian firms (2008) by SFG
- The value of imputation credits as implied by the Methodology of Beggs and Skeels (2006)

The AER gave full weight to the Beggs and Skeels dividend drop-off study and dismissed SFG's report because of (among other factors) concerns over SFG’s underlying data set and the arbitrary use of Cook's D-statistic by SFG to exclude influential observations from the regression analysis.[62] The AER concluded:

[60] Australian Competition Tribunal, *Reasons for decision*, 2010, p. 31.
[61] ibid., p. 32.
[62] AER, *Final decision, WACC parameters*, May 2009, p. 445.

> The AER is less confident about the reliability of SFG's results due to the identified data problems (eg. Noise) and the sensitivity of it results to the sample selected. In a relative sense, the AER consider the higher confidence may be placed upon the Beggs and Skeels study, due to the reported data filters and the reported lower standard deviations of key variables compared with the SFG study.[63]

12.6.3.2 AER draft decision

In the Victorian Draft Decision, the AER maintained its position from the WACC review and continued to rely solely on Beggs and Skeels (2006). While some revisions to the SFG study had been made since the WACC review, the AER continued to place no reliance on this study because of several concerns, mainly filtering and data quality, the use of cook's D statistic and SFG's economically implausible results.

12.6.3.3 Victorian DNSP revised regulatory proposals

In their revised proposals, the Victorian DNSPs have dismissed the AER's concerns about SFG's dividend drop-off study and insist that the SFG (2010) study provides the best estimate of theta. The DNSPs' sentiments are encapsulated by United Energy's comments:

> The SFG study is more comprehensive than the Beggs and Skeels (2006) dividend drop-off study, the results of which the AER has used in its draft decision. The SFG study uses a dataset covering a much wider cross-section of businesses and also employs a longer time series of data, extending to a more recent period.[64]

The DNSPs also considered that the AER's sole reliance on the Beggs and Skeels study was inconsistent with the advice of the AER's consultants, McKenzie and Partington:

> Given the problems inherent in estimating gamma using either taxation or ex-dividend studies, we argue in favour of a balanced approach. Since the best estimation techniques are beset with problems, the most logical approach is to consider the evidence on balance across all available sources. In this respect, the AER's approach of considering both ex-dividend and taxation statistics has merit, but we would recommend a broader range of studies to triangulate the evidence considered by the AER.[65]

Accordingly the DNSPs contended that it is unreasonable for the AER to have placed so much weight on the findings of Beggs and Skeels, particularly as the data and code for this study and not available for scrutiny by any stakeholder. For this reason, the DNSPs contend that Beggs and Skeels can be considered no more reliable than SFG (2009).

The Victorian DNSPs submitted a new report by SFG which addresses each of the AER's concerns with the revised SFG (2010) study. In particular, the DNSPs note that the AER's concerns with the SFG (2010) study are either exaggerated or unwarranted, in relation to the following:

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63 ibid., p. 441.
64 United Energy, *Revised regulatory proposal,* July 2010, p. 207.
65 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, pp. 3–4.

- Multicollinearity
- Filtering and data quality
- Use of cook's D statistic
- Zero and negative drop-offs
- Economically implausible results
- Positive intercepts

Multicollinearity

The Victorian DNSPs stated that the AER has failed to acknowledge that multicollinearity is no more of a concern for SFG (2010) than for Beggs and Skeels (2006). In addition, the DNSPs highlighted that McKenzie and Partington consider that the issue of multicollinearity is a problem inherent to all dividend drop-off studies, and not unique to the SFG (2010) study. The Victorian DNSPs further note that the standard errors of the parameter estimates are not of sufficient magnitude to suggest that multicollinearity represents a material concern. This point is supported by a report written by Associate Professor Christopher Skeels that reviewed the results of SFG (2010).[66]

SFG data set quality

The Victorian DNSPs considered that the SFG (2010) study properly treats its dataset to exclude those observations that are deemed unacceptable on an economic basis. The DNSPs support this point with the independent study conducted by Dr John Field, which was also submitted in their initial proposals.

Field set out a procedure to determine the likely number of unacceptable observations within SFG's data set based on examination of a sample within SFG's data set. Field identified a sample of 150 random observations from SFG's data set of 3201 observations to be analysed for this purpose.

SFG then analysed the sample 150 random observations identified by Field from its data set of 3201 and found 14 observations to be excluded due to price sensitive announcements being made in relation to them, and two observations where dividends were understated. The Victorian DNSPs note that the observations identified in Field's analysis have been excluded from SFG's data set, and that this had no material effect on the estimate of theta, with SFG's results being stable. For example, JEN noted there was only a change to the parameter estimate at the third decimal point.[67]

The Victorian DNSPs argued that the AER's draft decision did not consider the materiality of the observations' unacceptability and its likely effect on the results. To this end, SFG on behalf of the Victorian DNSPs argued that the AER misinterpreted Field's analysis in describing the 14 observations as being "unreliable", rather, they are the set of observations for which there is even a remote possibility of a price-

66 C. Skeels, *Response to Australian Energy Regulatory Draft Determination*, 13 January 2010, section 3.1. See Appendix 12.7.
67 JEN, *Revised regulatory proposal*, p. 264.

sensitive announcement anywhere near the ex-date and their removal makes no difference to the estimate of theta.[68] To this end, SFG stated:

> There is no evidence to suggest any bias would be caused by including even observations with a substantial price-sensitive announcement on the ex-date itself. In a large sample, it is likely that the sample will contain some positive and some negative news announcements and these will tend to cancel out. In this regard we note that Beggs and Skeels have not screened out observations on the basis of stock exchange announcements being made around the time of the ex-dividend date.[69]

Cook's D statistic

The Victorian DNSPs contended that the Cook's D statistic was an appropriate method to identify and exclude those observations which were economically unreliable.[70] The Cook's D statistic is a standard statistical technique used for identifying influential outliers in a data set.[71] This method was used by SFG to identify the most influential one per cent of observations within its data set, then to interrogate and exclude those observations it deemed unreliable. The Victorian DNSPs rejected the AER's criticisms that this technique excludes only individually influential, rather than groups of observations that are jointly influential. The Victorian DNSPs noted that the AER did not substantiate its concerns in this regard, as expressed by CitiPower:

> The AER has provided no examples of the types of decisions it may consider to be 'jointly influential' or how this may manifest itself in the results. This is merely an allusion to a possible concern, but is not supported by anything other than an assertion of the AER.[72]

The DNSPs also argued that the Cook's D Statistic approach should be considered in light of the other diagnostic checks conducted by SFG that demonstrate significant stability in its estimate.[73]

Zero and negative drop-offs

The Victorian DNSPs contended that McKenzie and Partington did not substantiate their claim that the number of zero and negative drop-off observations within the SFG (2010) dataset was 'higher than expected'. Furthermore, it may be possible that the Beggs and Skeels (2006) study contains a similar number of zero and negative drop-off observations. The DNSPs considered that zero and negative drop-off observations are caused by purely random events and if arbitrarily removed from the dataset, would inevitably bias the results.[74] SFG stated the following in this context:

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68 SFG, *Issues related to estimating gamma*, July 2010, p. 19.

69 ibid.

70 Citipower, *Revised regulatory proposal* ,p. 366; Powercor, *Revised regulatory proposal,* p. 357; JEN, *Revised regulatory proposal*, pp.264–265, SP AusNet, *Revised regulatory proposal* pp. 339–340; United Energy, *Revised regulatory proposal*, p. 209.

71 SFG, *Issues related to estimating gamma*, July 2010, p. 20.

72 CitiPower, *Revised regulatory proposal*, p. 366.

73 CitiPower, *Revised regulatory proposal*, p. 366, Powercor, *Revised regulatory proposal*, p. 357, JEN, *Revised regulatory proposal*, pp.264–265, SP AusNet, *Revised regulatory proposal*, pp. 339–340; United energy, *Revised regulatory proposal*, p. 209.

74 CitiPower, *Revised regulatory proposal*, p. 367.

> It would be wrong to routinely omit zero or negative drop-off observations. Such observations should only be omitted if they are erroneous, and there is no evidence of that.[75]

Economically implausible results

JEN and United Energy questioned the AER's assessment that SFG's theta estimate is not statistically different from zero and the estimate of cash dividends is greater than one dollar. United Energy notes:

> The AER hasn't referenced a particular report, but is presumably drawing upon results in SFG 2009….SFG has implemented a number of refinements to its approach since the publication of the February 2009 study and so the issues to which the AER refers may no longer be manifesting themselves in the estimation results.

JEN noted the AER's concern that the SFG study contained observations where the value of cash dividends is greater than one dollar represents an implausible point estimate.[76] However, the confidence interval surrounding the point estimate includes economically plausible values. In response, JEN cited the following comment from Skeels:

> [i]f the point estimate is economically implausible but the confidence interval includes economically plausible values, as the preferred SFG results do, then the correct interpretation of the estimates is that they suggest that the true parameter is near to the boundary of economically plausible values. They do not suggest that the true parameter value is an economically implausible value. To attach an implausible interpretation to something when a plausible interpretation is equally probable does not constitute a fair assessment of the statistical evidence.[77]

Intercepts

On behalf of the Victorian DNSPs, SFG noted that in the Victorian draft decision, the AER incorrectly asserted that SFG's regression equation contained a statistically significant intercept term. SFG claimed that the intercept terms from the analysis of post July 2000 data from SFG report of 4 February 2010 are all negative.[78]

12.6.3.4 Issues and AER considerations

The AER reiterates its position from the WACC review that any attempt to estimate theta from market prices should be treated with caution, given the inherent noise and anomalies in the estimation.[79] Despite this, the AER also acknowledges that dividend drop-off studies can provide some useful information for the value of imputation credits in the Australian economy. The AER recognises the advice of McKenzie and Partington, who notes the following in relation to dividend drop-off studies:

> This technique brings with it a host of issues related to the problem of estimating the value of the package of cash dividend and franking credit and splitting the package into its components for the purposes of estimation. In

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75 SFG, *Issues related to estimating gamma*, July 2010, p. 18.
76 JEN, *Revised regulatory proposal*, p. 265.
77 C. Skeels, 13 January 2010, Response to Australian Energy Regulatory Draft Determination, p. 28. See Appendix 12.11
78 SFG, *Issues related to estimating gamma*, July 2010, pp. 19–20.
79 AER, *Final decision, WACC parameters*, May 2009, p. 430.

> particular presence of noise in the data and measurement errors present severe problems in generating reliable estimates of the variables of interest. These data problems mean that it is common in ex-dividend studies to engage in some form of data filtering and also to partition the data into various samples, which brings with it many issues related to selection criteria and representatives of results.[80]

In reviewing the recent arguments presented by the DNSPs, and in the context of the debate on these matters during and since the WACC review, the AER remains unconvinced that SFG's approach, including all revisions made up to its 2010 study, is capable of producing a reliable estimate for the value of theta. Furthermore, the DNSPs have not advanced any arguments to suggest the AER should not rely on the theta estimate of Beggs and Skeels (2006).

The symptom of multicollinearity is common to all dividend drop-off studies. However, it is a fundamental issue in the current debate as it can present a significant problem when combined with an unreliable data filtering approach.

While the AER recognises that Beggs and Skeels has not been subjected to full scrutiny due to the lack of access to its dataset and code[81], it has the key feature of applying an appropriate filtering methodology where a set of economic criteria are defined at the outset of the study (ex ante) and those observations that do not meet the economic criteria are removed. This is a rigorous and thorough filtering approach. By contrast, the key feature of SFG's work is its use of an ex post filtering method which undermines the reliability of its parameter estimates. In empirical studies, the ex ante development and application of economic criteria to identify unreliable observations is superior to any ex post sample filtering method. The former is also more appropriate for a dividend drop-off study given that regression results can be sensitive to a small number of observations.

The following sections summarise the AER's considerations of issues around dividend drop off studies and the DNSPs' latest arguments:

- Revisions to SFG's study
- The issue of multicollinearity
- Data filtering and Cook's D statistic
- Sensitivity analysis of SFG's results
- Negative intercepts in SFG's results
- Zero and negative drop offs
- Confidence region and economically implausible results
- Joint confidence regions

80 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, p. 3.
81 Noting that the study has been subject to a rigorous peer review process and published in a well respected and authoritative specialist journal.

- Field's sampling confidence regions

Revisions of SFG's study with respect to the AER's determinations

The SFG dividend drop-off study has been submitted to the AER in multiple iterative forms, during the WACC review and in Queensland and South Australia distribution determinations. Each progressive revision has slightly refined the study based upon the AER's criticisms made in each of these processes. Subsequent to the WACC review, the AER received a revised report from SFG, which had undergone an examination by Professor Skeels for the South Australia distribution determination. Professor Skeels considered many of the AER's concerns raised in the WACC review, and endorsed a revised SFG estimate that reflected his recommendations. In particular, Skeels recommended that SFG's approach to using Cook's D statistic should identify the top one per cent of influential observations in SFG's data set and exclude those influential and unreliable observations where an economic justification for the exclusion can be given. This approach contrasted to the Beggs and Skeels (2006) study which Skeels acknowledged:

> The approach of Beggs and Skeels (2006) was to remove almost everything that was of dubious economic quality regardless of whether or not it would exert any influence on the results.[82]

Beggs and Skeels (2006) use the following six filters:[83]

1. Considered only companies and trusts whose primary listing is on the Australian Stock Exchange.
2. Excluded observations from the data set where the dividend payment, corporate tax rate, cum-dividend share price, or the ex-dividend share price was not known.
3. Eliminated all cases where the market capitalisation of a company was not reported, or where the weight of market capitalisation in the All Ordinaries index was less than 0.03 per cent.
4. Screened for any companies that changes their basis for quotation within five days, either side of the ex-dividend day.
5. Excluded special dividends payments.
6. Data from the extremely volatile month of October 1987 were removed.

Skeels also noted the following about the use of Cook's D statistic:

> In my opinion, the use of Cook's D statistic can be justified on the basis of it being a cost saving device. It is expensive to interrogate observations and if the use of Cook's D statistic allows you to focus limited resources on where they might be employed most valuably then that is a good outcome on both economic and statistical grounds.[84]

On the basis of Skeels' advice and Professor John Field's analysis, SFG made the following filtering choices with respect to its data set:

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82 C.Skeels, *Response to AER questions*, 2009, p. 6.
83 Beggs and Skeels, *Market arbitrage of cash dividends and franking credits*, 2006, p. 252.
84 C.Skeels, *Response to AER questions*, 2009, p. 8.

- Removed 11 observations after applying Cooks D statistic to identify the top one per cent of influential observations in deriving the regression result of the unfiltered data. The observations identified by Cook's D statistic were examined to determine whether they were excludable on economic grounds.[85] This included the removal of two AngloGold Ashanti (ASX code: AGG) observations pertaining to price sensitive information being released around the ex-dividend date.[86]

- Removed nine observations of the Transurban Group security (ASX code: TCL) due to their high price, high dividend per share and staple security status.

- Corrected two erroneous observations (ASX code: GAS and APA) and identified 14 observations with price sensitive information announced within a five-day window around the ex-dividend day from reviewing a random sample of 150 observations. Note that the 14 observations are not removed from the SFG data used to derive the final estimate.

- Corrected one erroneous observation (ASX code: ICT) and added 14 missing observations.

As a result of all these filtering choices, the most recent SFG report (February 2010) produces an estimate of 0.23 of theta.

It is important to note that despite the series of refinement by SFG, each refinement (as summarised above) is made under a limited scope. For example, only 33 observations are examined for the removal of 11 unreliable observations on economic grounds. If these economic grounds are applied to the full data set, a larger number of unreliable observations will be found to be present in the data and exert an influence in the revised regression results. This raises the concern as to the reliability of SFG's underlying data set.

Multicollinearity

The AER disagrees with the Victorian DNSPs' argument that multicollinearity does not represent a material concern for the SFG dividend drop-off study. The AER considers that multicollinearity is a symptom inherent in all dividend drop-off studies, and exists as a result of the collinear relationship between cash dividends and imputation credits. The co-linear relationship between franked dividends and cash dividends is expressed in the following calculation of franking credits:

$$FC = D \cdot \left(\frac{T_c}{1 - T_c} \right) \cdot \frac{fr}{100}$$

Where:

FC franking credit

D cash dividend

[85] SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 13.

[86] C.Skeels, *A report prepared for Gilbert and Tobin: A Review of the SFG dividend drop-off study*, 2009, p. 34.

τ_c corporate tax rate

fr proportion of the cash dividend on which Australian company tax has been paid

Based on replication of the SFG study, it is clear that the following model specification was adopted by SFG to perform its dividend drop-off analysis:

$$\Delta P_i = \gamma_0 + \sum_j \gamma_{1j} d_j D_i + \sum_j \gamma_{2j} d_j FC_i + \varepsilon_i$$

The general form of the model contains only two main explanatory variables in explaining the price drop-off, namely the amount of cash dividend and the amount of franked credit. Since these explanatory variables are linearly related, it is difficult to accurately estimate their separate effects on the price drop-off.

Halcoussis notes the generic effects that multicollinearity would have on the results of a regression analysis:

- It may restrict the value of the R-squared, as the two explanatory variables are after the same variations in the ex-dividend share price changes, and therefore unable to make independent contribution to the prediction of the price changes.
- It may make the determination of the impact of an explanatory variable difficult as the effects of correlated variables are confounded. The coefficients may not be precisely as each estimated coefficient will capture part of the effect of the other variable.
- It may increase the variances of the regression coefficients and thus make them less significant and possibly insignificant. In some cases, the coefficients may change substantially or even reverse the sign.[87]

Given the presence of multicollinearity, measuring the implied value of imputation credits through dividend drop-off studies is uncertain, as it is difficult to isolate the effects of cash dividends and imputation credits. The presence of multicollinearity may also result in regression estimates being sensitive to small changes in observations. McKenzie and Partington acknowledge these points and note the following implications of multicollinearity for dividend drop-off studies:

> Researches typically proceed in the presence of multicollinearity on the basis that the point estimates of the independent variables are unbiased and consistent. There is a drawback however, as the estimated standard error for each estimate is quite large as it is difficult to decompose the partial effect of each variable…Alternative symptoms of the multicollinearity problem include regression estimates that are sensitive to sample changes or model specification.[88]

The AER notes McKenzie and Partington's advice that symptoms of multicollinearity in dividend drop–off studies include large standard errors and estimates of theta that are statistically insignificant.[89] Skeels also noted that symptoms of near perfect

87 Halcoussis, D. *Understanding econometrics*, 2005, pp. 118–119.
88 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, p. 45.
89 ibid.

multicollinearity include large standard errors and insignificant coefficient estimates.[90]

The AER notes McKenzie and Partington's analysis of SFG's data set shows that the coefficient of correlation between cash dividends and imputation credits is 0.70 for stock price observations after the 0.03 per cent size filter is applied. This number is 0.9899 for the 2052 observations in SFG's unfiltered data set where dividends are fully franked.[91] The AER considers that this high degree of correlation in the data indicates that SFG's results are prone to multicollinearity.

The AER acknowledges Diamond and Brooks' analysis and notes that there is no irrefutable test that can be used to determine whether multicollinearity is or is not a problem. The AER considers that the following standard techniques to test for multicollinearity are:

- Pair-wise correlation coefficient: the cut-off point is not well defined. Strong and/or medium linear relationship between two explanatory variables can provide a warning sign to multicollinearity

- Collinearity diagnosis: common techniques include the variance inflation factors used in the Diamond and Brooks report. Belskey, Kuh and Welsch (1980) recommended a two-step procedure; first, a condition number for the matrix of data values is computed, and second, a variance decomposition measure is used. Thresholds causing the multicollinearity are not well defined.

As agreed by SFG, there is no formal statistical testing for the presence of multicollinearity.[92] In addition, the diagnostic techniques can misdiagnose a collinearity problem. For example, low variance inflation factors do not guarantee low collinearity (as implied by Belsley).[93] Serious collinearity problems for data with limited variability can be undetected by variance inflation factors.

As stated by Beggs and Skeels, dividend drop-off studies rely on variations of franking levels and changes in corporate tax rates over time to estimate the individual effects of cash dividends and franking credits. The question is whether the mix of fully franked, unfranked and partly franked dividend events in a dividend drop-off study leads to sufficient collinearity to be a material concern. Based on the AER analysis, the SFG data set contains large subsets having the perfectly linear relationship between cash dividend and franking credits: i.e., of all data points, 24 per cent have FC = 0 * dividend, 45 per cent have FC = 0.43 * dividend, 6 per cent have FC = 0.52 * dividend, and 13 per cent have FC = 0.56 * dividend. It appears that there is limited variation of franking credit apart from changes associated with the amount of cash dividend. With little variation of its own, it is difficult to measure the individual effect of franking credit separately from that of cash dividend. This problem of limited variability in the explanatory variable also falls within in the context of multicollinearity.

90 Skeels, Response to Australian Energy Regulator draft determination, 13 January 2010, p. 17.
91 This is 2052 out of SFG's unfiltered sample of 5646 observations.
92 SFG, *Issues related to estimating gamma*, July 2010, p. 22.
93 Belsley, D.A., *Conditioning Diagnostics: Collinearity and Weak Data In Regression*, 1991, p. 28.

There appears to be a unique pattern of collinear relationship between cash dividends and franking credits, resulting in a dataset that is not informative of the partial effect of franking credit (holding cash dividend constant). This uniqueness may create difficulties in identifying the multicollinearity problem by standard diagnostics, such as what has been done by Diamond and Brooks and discussed in their report.

By way of further investigation, the AER has replicated the reported results on regression and collinearity diagnostics. The AER identified a coding error where the ancillary regression used in the FGLS has a typo – the variable P5F (i.e., the amount of franking credit distributed in period 5) was incorrectly typed as P5G (i.e., the amount of gross dividend distributed in period 5). However, the error is not material to change the results reported and is noted for completeness.

For the variance inflation factor analysis, one can argue that standard collinearity diagnostics, such as variance inflation factor, may fail to diagnose the unique multicollinearity problem in a dividend drop-off study.

For the Eigen-value decomposition analysis, Diamond and Brooks concluded the existence of the unfranked data plays an important role in allowing good estimates of the franking credit value. However, it is apparent that incorporating unfranked dividend observations into a dataset with franked dividend observations would bring additional data variations and therefore improve the estimation of the model. It is worth noting that the inclusion of unfranked dividend observations has not only changed the standard errors of point estimates, but also changed the values of point estimates themselves.

Nevertheless, the sub-sample analysis conducted by the authors shows that:

- The value of unfranked cash dividends, under each tax regime, is much lower than the value of cash component of franked cash dividends (see tables 5 and 6 of the report).

- The reported values of unfranked cash dividends, particularly the value of 0.9723 for the post-July-2000 period, appear to much higher than those yearly estimates reported for the same period in Beggs and Skeels (2006).

- The reported values of the cash component of dividends being around one are inconsistent with the general findings of the Australian studies that dividends are not fully valued. As advised by McKenzie and Partington, the Australian evidence shows that the cash component of dividends is valued at about 80 percent of face value.[94]

Given the multicollinearity problem in a dividend drop-off study, it is difficult to accurately decompose the price drop-off effect into the two related components of dividends: the cash component and the franking credit attached. It is likely that the SFG data have systematically over-estimated the market value of cash component and under-estimated the market value of franking credits. This is consistent with the

94 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, p. 31.

economic literature, which suggests that the value of a dollar of cash dividends would be valued by investors at less than a dollar.[95]

Finally, the AER considers that multicollinearity is a problem common to all dividend drop-off studies and it would mask the individual affects of cash dividend and imputation credits on the share price drop-off. Multicollinearity can make the results of dividend drop-off studies sensitive to even a small number of observations within the relevant data set. This is demonstrated below with the exclusion of a small number of observations from the SFG data set. The importance of data filtering to remove unreliable observations from the full data is therefore particularly crucial and should be applied thoroughly and with proper economic justification. Beggs and Skeels' method of developing economically justified filters and applying these ex ante to the entire data set contrasts from SFG's dividend drop-off study.

Data filtering and Cook's D statistic

The Victorian DNSPs considered that the SFG 2009 and SFG 2010 reports submitted to the AER as part of its South Australia determination should be relied upon to estimate the value of theta. The AER remains critical of the filtering approaches adopted by SFG in both reports. In particular, the AER considers that in each of its revised reports, SFG has only interrogated an arbitrary number of observations, rather than applying a rigorous filtering process to its entire data set. SFG's application of the Cook's D statistic is an ex-post sample filtering method based upon a partial economic justification to exclude observations from an arbitrarily chosen sample.

The AER notes McKenzie and Partington's advice that the use of Cook's D-statistic may introduce a bias into SFG's analysis because it only excludes individually influential observations that are economically unreliable. This process may not identify groups of observations that are jointly influential.[96] For instance, in Skeels' August 2009 report prepared for ETSA utilities, outlined the application of the Cook's D statistic to interrogate the SFG 2009 data set using two model specifications - model A (which adjusted the previous SFG study for changes in corporate tax rates) and model B (which made the same adjustment in model A and a further adjustment for market movements). Within the dataset were nine Transurban group (ASX code: TCL) with extremely high share prices and dividends per share that are jointly influential. The Cook's D statistic procedure applied by Skeels in model A excluded one of the nine influential TCL observations and the model B application none of the nine TCL observations.[97] SFG however, opted to exclude all of them on the basis that these extreme high priced securities have a substantial influence on coefficient estimates.[98]

The AER considers that the nine TCL observations, as a group, may have a substantial influence over the regression estimates. However, the Cook's D statistic failed to detect eight of the nine observations and all of the observations for the full datasets under models A and B, respectively. The incompleteness and inconsistency in

95 AER, *South Australian distribution determination 2010–2011 to 2014–2015*, Final decision, May 2010, p. 155.
96 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, p. 50.
97 Skeels, *A Review of the SFG Dividend Drop-off Study: A Report prepared for Gilbert and Tobin*, 2009, p. 34.
98 ibid.

the exclusions of observations highlights that the Cook's D statistic cannot be considered as representing the underlying population and nor does it provide a thorough filtering method to derive a sample of reliable observations that represent the underlying population. Accordingly, the resultant regression results may not be the true estimates, as a result of Cook's D statistic being used as a data filter. SFG's subsequent exclusion of the nine TCL observations shows that there is a need to remove jointly influential observations which may not be detected by the Cook's D statistics.

The AER notes that the process of the Cook's D statistic is iterative, in the sense that once it is applied, there is another group of top one per cent influential observations driving the regression results. SFG performs the Cook's D procedure only once each time it is applied. The AER notes that the most influential observations driving the next set of regression results are not interrogated by SFG. Belsley, Kuh and Welsch consider that the application of the Cook's D statistic may be prone to misuse, where high-influential data points could conceivably be removed solely to effect a desirable change in a particular estimated coefficient, its t value or some other regression output.[99] The AER maintains that the one per cent threshold for the Cook's D statistic chosen by SFG for considering data exclusion remains an arbitrary filtering choice.

Sensitivity analysis

The AER notes SFG's recent endorsement of its February 2010 updated study as to the robustness of the 0.23 estimate for theta:

> We then only filtered out observations that were identified as contaminated in some way. This analysis was provided to the AER in our report of 4 February 2010. It confirms the robustness of our theta estimate of 0.23 when special dividends are included.[100]

The AER has replicated the latest result of a 0.23 value of theta from SFG's February 2010 study and applied the Cook's D statistic to interrogate the SFG 2010 data set. The most influential observation observed was AGG, with a Cook's D statistic of 1.59. This result was identified by the AER in addition to the two AGG observations recognised and already excluded by SFG in an earlier report. AGG is a CHESS Depository Interest (CDI) and represents an interest in a foreign company. For a CDI it is difficult to isolate the share price change effect due to the stock going ex-dividend from other factors. This may represent a reasonable economic justification to exclude the AGG observation from the SFG data set. In addition, AGG is highly priced and pays high dividend per share, making it influential in the least squares-based regression. The AER conducted a sensitivity analysis of SFG's estimated theta using the following filtering options:

- if the AGG (19 February 2001) observation is excluded, the estimated value of franking credit is increased from 0.227 to 0.432

- if all the 12 AGG observations are excluded from the data, the estimated value of franking credit is increased from 0.227 to 0.506

[99] Belsley, D.A., E. Kuh and R.E. Welch, *Regression Diagnostics, Identifying Influential Data and Sources of Collinearity*, 1980, pp. 15–16.

[100] SFG, *Issues related to estimating gamma*, July 2010, p. 21.

- if all the top one per cent influential observations (based on Cook's D-statistic) are excluded from the data, the estimated value of franking credit is increased from 0.227 to 0.394. [101]

The AER does not endorse any of the theta estimates from this sensitivity analysis. These results merely demonstrate the sensitivity of SFG's theta estimate in light of small changes to the underlying data set.

It is clear that there is significant variation in the estimate of theta from dropping only a small number of observations that may not be reliable. This points further to the instability of SFG's 0.23 estimate for theta and also highlights how the application of the Cook's D statistic, as an ex-post sample filter, can dramatically alter the outcome of the theta estimate without regard to whether the observations should or should not be excluded based on economic or other justifications. An ex-ante data filter would exclude observations at the outset of the study, according to a set of economic criteria to limit the influence of unreliable observations that may distort the results of the study. The AER acknowledges that a thorough examination of SFG's dataset would be a costly and time consuming exercise, however an effort of this magnitude has already been undertaken by Beggs and Skeels.[102]

The AER notes that one data filter adopted by Beggs and Skeels is on the sampled securities are those of companies and trusts that are primarily listed on the ASX.[103] The AER observes that AGG's primary listing is on the Johannesburg Stock Exchange (JSE)[104] in South Africa and therefore is most likely excluded from the Beggs and Skeels data set. The AER considers that the inclusion of the AGG observation would result in more noise within the data set, owing to trading in AGG on its primary exchange.

Negative intercepts

Using data sets submitted by SFG in support of its February 2010 report, the AER has replicated the large number of regression results reported in the Jan 2010 and Feb 2010 SFG reports. The regression results show that the intercept terms in all the regressions are negative and statistically significant. The results appear to be consistent with the expected sign of the intercept term. As argued by McKenzie and Partington, in theory the intercept term should be zero or negative depending on the extent of arbitrage and the nature of transaction costs.[105] Hence, the AER no longer maintains its earlier position on this point.

Zero and negative drop-offs

The AER's draft decision cited the analysis of McKenzie and Partington, who noted the incidence of zero and negative observations that exist within the SFG data set. McKenzie and Partington noted that after making an adjustment for market

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101 We assume the same weights applied to sample observations as per SFG Feb 2010, p. 5.

102 For example, the reported number of ordinary dividend events for Beggs and Skeels (2006) was 5511 after filtering – see Beggs and Skeels, *Market arbitrage of cash dividends and franking credits*, 2006, p. 252. , while SFG's data set (after filtering) consisted of 3201 observations – see SFG, *Response to the AER draft determination in relation to gamma*, January 2010, p. 2.

103 Beggs and Skeels, *Market arbitrage of cash dividends and franking credits*, 2006, p. 252.

104 AngloGold Ashanti, *Annual Financial Statements*, 2009, p. 11.

105 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, p. 50.

movement, there were 489 observations with negative drop-off ratios out of 3201 observations (approx 15 per cent).[106] The AER observes that negative market adjusted drop-off ratios are implausible, indicating that the observed share price changes are not solely attributable to the distribution of dividend per se. The AER does not consider there is any theoretical ground to solely exclude these observations. The AER reiterates its point that an underlying data set should be interrogated using an ex-ante data filter coupled with economic justification for excluding problematic observations.

Confidence region and economically implausible values

In the Victorian draft decision, the AER identified a number of economic implausible values within SFG's results, where the observed cash dividend values were greater than $1, over the period 1 July 2000 to 10 May 2004.[107] The DNSPs contended that although these may be economically implausible point estimates, the confidence interval that can be constructed around the point estimates and within the confidence intervals are economically plausible values. Accordingly, Skeels notes the following:

> To attach an implausible interpretation to something when a plausible interpretation is equally probable does not constitute a fair assessment of the statistical evidence.[108]

The AER considers that with respect to cash dividends, the point estimate is the best estimate conditional on the data and regression model used.[109] Whilst recognising that values within the confidence interval represent possible true values of the estimated parameters, the AER does not consider that other points fit the SFG data as well as the point estimate. In addition, the fact that the sample data does not statistically differentiate an economically implausible point estimate from an economically plausible value does not mean all point estimates are economically reasonable.

When examining the point estimate of cash dividend, the AER considers the underlying economic theory from Brown and Walter (1986), Brown and Clark (1993) and Hathaway and Officer (2004) which suggests that the value of the cash dividend is less than one dollar - the SFG cash dividends data that is greater than one dollar are economically implausible values according the theory underlying dividend drop-off studies.

Joint confidence regions

The AER considered the use of confidence intervals in the WACC review

> The AER acknowledges that confidence intervals are a measure of statistical precision, and accepts that confidence intervals (standard practice of which is to use 95 per cent confidence intervals) are a relevant consideration in the context of the persuasive evidence test where empirical data is being considered. The AER also accepts that as the test relates to the need for persuasive evidence to depart from the previously adopted value, there is nothing asymmetric or inconsistent in:

106 ibid., p. 38.
107 AER, *draft decision*, June 2010, p. 543.
108 C. Skeels, *Response to Australian Energy Regulatory Draft Determination*, 13 January 2010, p. 28. See Appendix 12.11
109 D Halcoussis, *Understanding econometrics*, 2005, pp. 54–56.

  - considering the upper 95 per cent confidence interval where the point estimates from the empirical data are below the previously adopted value, and

  - considering the lower 95 per cent confidence intervals where the point estimates from the empirical data are above the previously adopted value

The AER considers that it is the weight of the evidence overall that determines whether or not the evidence is persuasive to depart from the persuasive adopted parameter. In relation to empirical evidence, this includes consideration of:

- the statistical precision and reliability of the empirical estimates (of which confidence intervals are one element thereof)

- the availability of data (cross-sectional and across time)

- the consistency of empirical estimates (over time, across businesses, across empirical methods), and

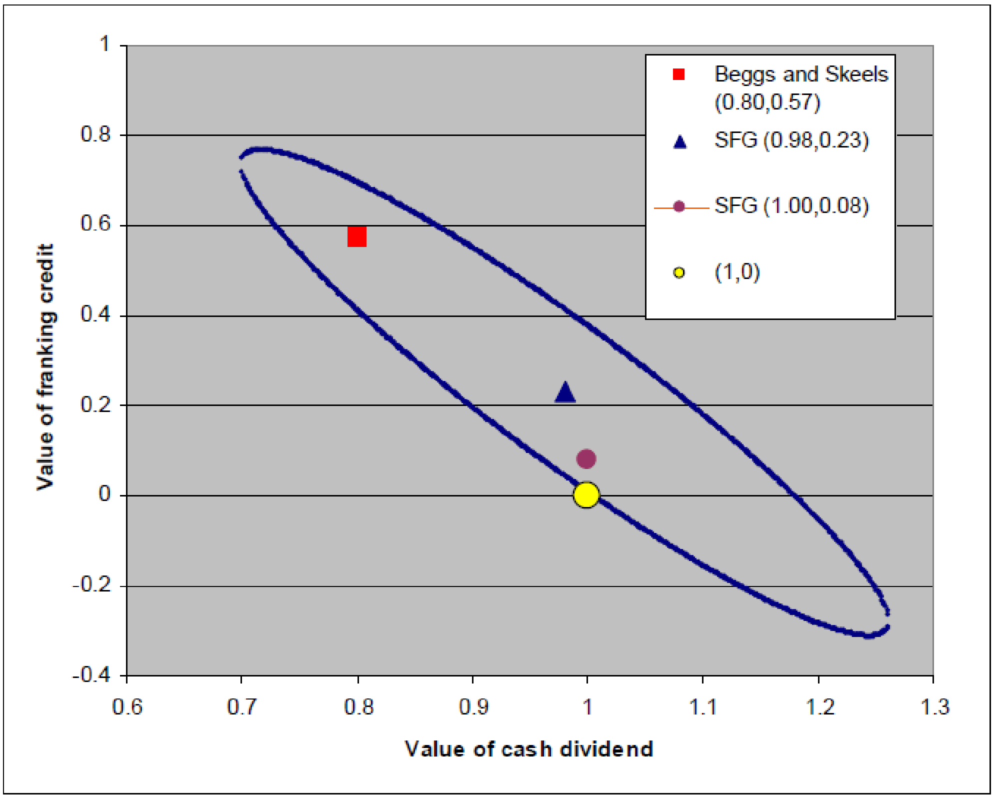
- the economic reasonableness or the plausibility of the estimates.[110]

In this context, the following chart provided by SFG is relevant to the extent it can be interpreted to indicate that the values of theta provided by SFG are not statistically significantly different from those of Beggs and Skeels.

The chart shows the range of likely values of franking credit, jointly with that of cash dividend, using the joint confidence interval analysis that accounts for multicollinearity between the variables. The wide coverage of confidence region indicates the imprecision of the SFG point estimate of (0.98, 0.23), the central point of the region. Due to this imprecision, the SFG study fails to statistically differentiate its best point estimate from other possible values, such as the Beggs and Skeels estimate of (0.80, 0.57).

[110] AER, *Final decision, WACC parameters*, May 2009, p. 90.

Figure 12.1 Joint confidence interval: Beggs and Skeels and SFG dividend drop-off estimates



Source: SFG[111]

The AER disagrees with SFG on its argument that any pair of parameter estimates inside the joint confidence region fit the data equally well. It is the point estimate of (0.87, 0.23) that fits the SFG data best. Conditional on the data and method used by SFG, this point estimate is the best guess of the true value of parameters.

However, a point estimate with larger confidence interval is less precise. The wide joint confidence region in the SFG study indicates the lack of precision. In addition, it is apparent that the results of the Beggs and Skeels (2006) study fits within the joint confidence region of the SFG study.

The lack of statistical precision and other issues of data filtering and reliability of the underlying data set associated with the SFG study considered together, indicate that the results of the SFG study are not reliable. The AER considers that the SFG study does not constitute persuasive evidence justifying a departure from the AER's reliance on the point estimate of theta derived from the Beggs and Skeels (2006) study for the purpose of arriving at an estimate of gamma in the SORI.

John Field sampling confidence regions

The AER notes that, rather than applying this analysis, SFG revised its estimates after excluding the 14 unreliable observations and correcting two dividends that were found to be understated, and found negligible change in its results. However, when this

111 SFG, *Response to the AER draft determination in relation to gamma*, January 2010, p. 7.

proportion is applied to the entirety of SFG's data set, Field's analysis suggests that between 198 and 530 observations are unreliable and should be excluded from SFG's data set. This indicates a high level of unreliability within SFG's whole dataset of 3201. The AER notes that re-estimating the regression results after analysing only 150 observations and correcting 16 observations does not mitigate this problem. This is consistent with McKenzie and Partington's advice, which stated that auditing a random sample of observations does not serve any useful purpose.[112] Additionally, it is also relevant that the 14 observations found by Field did not include the AGG observation identified by the AER in its sensitivity analysis.[113]

12.6.3.5 AER conclusion

The AER still has significant concerns about the SFG study. The AER continues to be concerned about SFG's data set and use of the Cook's D approach to conduct data filtering. The SFG theta estimate remains sensitive to a small change to the observations in its data set. The SFG study cannot be relied upon at this point in time. The AER considers that based on the material currently available, there is no persuasive evidence justifying a departure from the AER's approach in the SORI of relying on the point estimate of theta derived from the Beggs and Skeels (2006) study. The AER considers that based on the material currently available, for the Victorian distribution determinations it is still appropriate to give full weight to the Beggs and Skeels (2006) dividend drop-off study and no weight to the SFG study.

12.6.4 Issues in estimating theta from tax statistics

In its reasons for decision on 13 October 2010 regarding the estimation of gamma in the South Australia and Queensland distribution determinations, the Tribunal found error in the AER's approach to tax statistics studies.

The Tribunal stated that the figure the AER derived from Handley and Maheswaran (2008) did no more than confirm that the Beggs and Skeels (2006) figure was not to be ruled out as being too high.[114] The Tribunal also stated that there was no logic to the AER's approach of adjusting an upper bound on the value of theta derived from the Handley and Maheswaran (2008) estimate for the post-July 2000 period by averaging it with the lower figure that Handley and Maheswaran (2008) estimated for the period 1988–2000.[115]

- The Tribunal seeks a report on theta from the AER which proposes an approach that correctly uses tax statistics studies.[116]

Given the timing considerations, the further work as part of the Tribunal proceedings is not available for the Victorian distribution determination. The AER's consideration of tax statistics studies in the Victorian distribution determination is based on the information currently available before it.

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[112] McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, p. 33.
[113] SFG, *Response to the AER draft determination in relation to gamma*, January 2010, p. 17.
[114] Australian Competition Tribunal, *Reasons for decision*, 2010, p. 20.
[115] ibid., p. 21.
[116] ibid., p. 32.

12.6.4.1 AER draft decision

In the Draft Decision, the AER maintained its conclusion from the WACC review that the 2008 tax study of Professors John Handley and Krishnan Maheswaran ('H&M') provided a relevant and reliable upper-bound estimate of theta in the post-2000 period. The study estimates theta using tax statistics from the Australian Tax Office (ATO) that have been compiled from annual tax returns.

The AER's draft decision maintained the approach adopted for the SORI of taking the simple average of utilisation rates estimated by H&M over the periods 1990–2000 and 2001–2004. This was then combined with the estimate of theta from the Beggs and Skeels (2006) dividend drop-off study to estimate the final value of theta.

12.6.4.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs contended that tax studies should not be used to estimate the value of theta, principally as they provide an upper bound or theoretical maximum value of theta. In this context, SFG noted that the AER has illogically interpreted the values of the utilisation rates that H&M estimate over the two periods 1990–2000 and 2001–2004 when combining these two values in determining an overall value of theta.[117]

Furthermore, the DNSPs considered that the H&M tax study in particular should not be relied upon by the AER. This conclusion is drawn from reports commissioned from Dr Neville Hathaway, which contend that the methodology and data used by H&M to estimate theta are unsound. Hathaway’s main conclusions regarding the H&M study are as follows:

- The H&M study should not be used for application to corporate and regulatory issues within Australia
- The results are contrived as they are based on analysis of data that the authors have themselves created by their assumptions
- They ignore significant changes in the taxation regime associated with franking credits and miss important data
- The underlying data, provided by the ATO, is unreliable
- The paper does not address the access of investors to company tax via credits. It focuses solely on the credits of distributed dividends and does so via contrived tax statistics. Notwithstanding that tax statistics can only give an upper bound for theta, the problems with the estimates within the paper make it most unsuitable for practical use.[118]

The DNSPs further claim that a number of assumptions and qualifications in the H&M study are not interrogated by the AER.[119]

[117] SFG, *Issues related to estimating gamma*, July 2010, pp. 26–27.
[118] Hathaway, *A measure of the Efficacy of the Australian Imputation*, *Tax System*, p. 3.
[119] See for example SP AusNet, *Revised regulatory proposal*, 2010, p. 337.

12.6.4.3 Consultant review

Handley responded to the arguments presented by the DNSPs and Hathaway, in particular the criticisms that the H&M study made unsubstantiated or unreasonable assumptions in deriving its estimates. Overall Handley considers that Hathaway's criticisms are based on misunderstandings or are without foundation, and Hathaway's report "in no way discredits the Handley and Maheswaran (2008) study as the DNSPs would suggest".[120]

12.6.4.4 Issues and AER considerations

The AER does not believe that there is sufficient reason or evidence to over-ride its view that the assumptions made by H&M are reasonable, and as such the study provides valuable information in establishing a value of theta. The AER's approach to averaging the H&M estimates to derive a point estimate of theta from tax statistics is a conservative and practical method of incorporating this information, and recognises the limitations inherent in this type of study. Based on the limited information available, the AER maintains that the point estimate of 0.74 produced from tax studies is still appropriate.

The AER acknowledges that the study relies on a number of assumptions which have been made where only limited data are available, as they are not reported by the ATO. H&M acknowledge this and note:

> We acknowledge upfront that our measure is incomplete, for a full assessment of the imputation tax system would be based on considerations of neutrality, equity and administrative simplicity from both domestic and international perspectives.[121]

However, the AER accepts Handley's view that Hathaway and the DNSPs have incorrectly argued that the H&M study makes unsubstantiated and unreasonable assumptions. Additionally, the AER notes that Hathaway's analysis merely implies that these assumptions are unreasonable without providing sufficient evidence to demonstrate that this is the case. The H&M study has been peer-reviewed by members of the Economic Record publication, which provides scrutiny of H&M's assumptions and should provide further comfort as to their reasonableness.

The remainder of this section summarises and responds to the main arguments presented by the DNSPs and Hathaway, as well as comments by Handley, as follows:

- Suitability of tax statistics to estimate theta
- Averaging two periods from Handley and Maheswaran studies was inappropriate
- ATO data reconciliation with financial statements
- H&M data construction process
- Post-2000 data issues

[120] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, pp. 21, 33.
[121] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 83.

- Double counting of franking credits
- Missing data
- Comparing franked and unfranked dividends
- Excess credits 1990-2000

Suitability of tax statistics to estimate theta

The Victorian DNSPs maintain that tax study estimates provide only an indirect measure of the market value of imputation credits. In this vein, JEN noted:

> Tax studies would only be relevant to estimating theta if one assumed that the value of redeemed credits was equal to 100 per cent of their face value. If on the other hand, the value of these credits to redeeming investors was only 50 per cent of their face value, then theta would be 50 per cent of the redemption rate.[122]

SP AusNet also contended that tax studies should not be used to estimate theta:

> SP AusNet considers that the AER should not take into account these "upper bound" estimates from tax studies which are at best indirectly linked to the value of imputation credits.[123]

Similarly, SFG suggests that H&M results simply measure the proportion of credits claimed by investors and not necessarily the redemption value of those credits.[124]

The AER maintains its position that tax statistics do provide relevant information for estimating the value of imputation credits. The distribution of franking credits represents a means by which a credit for taxes paid by the company is passed onto shareholders.[125] Investors will utilise such credits to offset their taxable income, and reduce their tax liability, to the extent that their tax status and domicile permits. It is the reduction in personal taxes, if any, as a result of receiving and utilising imputation credits that is the source of value of credits to the investor. Handley acknowledges this and notes:

> In this regard, tax statistics concerning the extent to which franking credits have been used by investors to reduce their personal taxes are then relevant to estimating gamma.[126]

The H&M estimate is an aggregate reduction in personal taxes due to the aggregate receipt of franking credits (ignoring the time value loss of money from receipt of the franking credit and receipt of the tax saving.[127] As it is significantly unlikely that credits would be worth more than this amount, and in the absence of a market for the trading of franking credits, the redemption rate represents an upper bound on the value of a distributed imputation credit (theta). This is noted by H&M:

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122 JEN, *Revised regulatory proposal*, 2010, p. 258.
123 SP AusNet, *Revised regulatory proposal*, 2010, p. 336.
124 SFG, *Issues related to estimating gamma*, July 2010, p. 25.
125 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 17.
126 ibid.
127 ibid., p. 20.

> The purpose of this paper is to examine whether the elimination of the double taxation of dividends has in fact occurred. In particular, we measure the efficacy of the Australian imputation tax system by the extent to which imputation credits have reduced the personal tax liabilities of equity investors in Australian firms.[128]

In addition, the AER notes that the H&M study is entirely relevant for the purpose of estimating imputation credits, as was initially acknowledged by the authors, who stated:

> Our results are relevant not only to the ongoing policy debate concerning the efficacy of integration tax systems but also are of relevance to the application of various equilibrium asset pricing models that require an estimate of the value of an imputation credit.[129]

The AER also reiterates that its reliance on tax statistics is consistent with previous advice obtained from McKenzie and Partington who recommend a balanced approach should be taken to estimate gamma, including consideration of information drawn from multiple types of studies.[130] This addresses SFG's argument that the H&M results simply represent the proportion of imputation credits claimed by investors, rather than the redemption value of imputation credits.[131]

The AER therefore maintains it is appropriate to consider dividend drop-off studies and tax studies to inform an estimate of theta. Furthermore, H&M is reasonable and appropriate for the AER's purpose of estimating the value of theta.

Averaging two periods from H&M was inappropriate

H&M produces two separate sets utilisation rates of imputation credits for the periods 1990-2000 and 2001-2004. The AER's approach for the SORI, and the Victorian draft decision, took a simple average of the two separate utilisation rates to produce an upper bound estimate of theta. SFG notes that the AER's approach of averaging the two periods to produce an overall rate of theta was methodologically flawed and is clearly illogical.[132] In support of this argument, SFG uses the following analogy:

> If someone buys a Gold Lotto ticket, they might win anything from zero to $10 million. If they buy a Powerball ticket, they might win anything from zero to $20 million. This does not imply that the person should expect to win $15 million on average when they buy lottery tickets. Upper bounds cannot be averaged to obtain expected outcomes.[133]

Based on the material currently available, the AER considers that the 0.74 point estimate of theta generated from H&M is appropriate given certain practical considerations. In particular, H&M assume that resident individual and fund investors redeem 100 per cent of imputation credits over the period 2001-2004 - the utilisation rate for resident investors over 2001-2004 is therefore assumed to be 1. This is based on the tax change that took place on the 1 July 2000, which entitled resident investors

128 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation* Tax System, 2008, p. 83.
129 ibid., p. 93.
130 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, pp. 3–4.
131 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 19.
132 SFG, *Issues related to estimating gamma*, July 2010, pp. 26–27.
133 ibid.

to a full cash refund for imputation credits in excess of their tax liability. H&M note that this is consistent with investor rationality, and therefore assigns a zero value to excess imputation credits over the period 2001-2004.[134] The AER notes that the relevant starting point in estimating theta from H&M is the 0.81 value, as this estimate reflects the most recent tax reforms that affect the Australian imputation system. The AER considers that this is the most current estimate of the theoretical upper-bound value for gamma, not accounting for practical considerations.

The AER accepts this assumption, but makes the practical consideration for the time value discount from when an imputation credit is received to when it is utilised. As an aside, the AER notes that there is some evidence to suggest that the holding period rule does not severely influence the utilisation rate of imputation credits for resident investors. The holding period rule requires traders to hold a share for 45 days around the ex-dividend date in order to gain entitlement to any attached franking credit. The holding period rule therefore precludes some short-term investors who are trading around the ex-dividend date to receive the franking credit.[135] The AER observes that the holding period rule was made effective in 1997 but not enacted until 1999.[136] The AER notes Handley's advice that there is small observed changes in the trend of utilisation rates of resident investors for the period before (pre-1999) and after (post-1999 up to 2000 before the cash rebate of excess imputation credits was allowed).[137] Furthermore, Handley states:

> Since the rule was operating at this time and assuming the less than 100 per cent utilisation is fully attributable to the impact of the 45 day rule (which would not be the case since credits were not refundable at that time), then the rule would have had about a 5–10 per cent impact on the utilisation rate.[138]

This is demonstrated in the following table from H&M:

[134] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, pp. 85–86.
[135] Beggs and Skeels, *Market arbitrage of cash dividends and franking credits*, 2006, p. 251.
[136] ibid.
[137] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 31.
[138] ibid.

Table 12.4 Aggregate utilisation rate of imputation credits by resident and non-resident investors

Utilisation rate	'90	'91	'92	'93	'94	'95	'96	'97	'98	'99	'00	'01	'02	'03	'04	Mean '90–'00	Mean '01–'04
Individuals	0.95	0.95	0.93	0.89	0.92	0.94	0.94	0.93	0.94	0.89	0.90	1.00	1.00	1.00	1.00	0.92	1.00
Funds	0.64	0.65	0.62	0.70	0.71	0.54	0.61	0.65	0.66	0.65	0.65	1.00	1.00	1.00	1.00	0.64	1.00
Non-residents	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.07	0.05	0.07
Total	0.67	0.61	0.7	0.64	0.69	0.69	0.67	0.67	0.69	0.69	0.67	0.83	0.80	0.80	0.80	0.67	0.81

Source: Handley and Maheswaran (2008)[139]

Handley acknowledges that the utilisation rate estimated in H&M ignores the time value difference between receipt of the imputation credit and the attached tax saving.[140] For this reason, the true value of theta must be below those estimates derived from tax statistics. In averaging the post and pre-2000 periods, the AER takes the 0.81 theoretical upper-bound estimate and adjusts it downward to generate a point estimate of 0.74 to reflect the time value loss of money. This time value loss would approximately reflect a period of no more than a period of 18 months (being the time taken between when a credit is received to when it is utilised) discounted at the risk free rate given the certainty of investors being able to utilise the credits.

The AER considers that the estimate of 0.74 would conservatively reflect the time value loss of money, given the lack of appropriate data to undertake a more precise calculation. As per Handley's advice, the AER also concludes that the holding period rule would not have a material effect on the utilisation rates estimated by H&M. The resulting value of the reduction is likely to be conservative when considering the magnitude of time value loss as described above.

ATO data reconciliation with financial statements

Hathaway concludes that "ATO statistics cannot be relied upon for making conclusions about gamma and theta" as the underlying data supplied by the ATO is unreliable.[141] The basis of this claim lies in Hathaway's analysis of ATO-published imputation credit and dividend data spanning 1988 to 2008, and his inability to reconcile this data with equivalent estimates reported in financial statements for the period 2004–2008. In particular, Hathaway notes:

> These two sets of data, taxation and financial, do not reconcile to the amount of $42.6 billion of franking credits over the period 2004-2008. In context, this is 27% of the reported distribution of $149 billion of credits.[142]

The AER does not consider that Hathaway's inability to reconcile ATO data invalidates the study performed by H&M. As Handley notes:

139 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 90.

140 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 20.

141 Hathaway, *Imputation Credit Redemption: ATO data 1988-2008*, July 2010, p. iv.

142 ibid.

> …it is not necessarily the case that Hathaway has actually identified a problem with the ATO data - all that can be said at this stage is that, based on the information disclosed in the ATO Tax Statistics, Hathaway is unable to reconcile certain parts of it. In other words, an inability to reconcile data does not automatically mean there is a problem with the data. For example, a plausible explanation is that the ATO simply hasn't published enough information to allow Hathaway to complete his reconciliation.[143]

As acknowledged in H&M, there are difficulties and limitations in estimating utilisation rates from ATO data post 2000-2001 and these issues are discussed further below. In addition, Handley notes that Hathaway's findings in relation to the period 2004–08, has limited relevance to the H&M study, which included data for the period 1988–2004. The AER considers that the discrepancies identified by Hathaway may reflect the ATO not releasing a complete set of information rather than any underlying errors in their data.

In this regard, the AER considers that Hathaway's conclusion about the reliability of ATO data to be erroneous.

H&M data construction process

Hathaway notes that H&M calculate unfranked and franked dividends received by non-resident investors over the period 1988-2001 implied from Dividend Withholding Tax (DWT) data. Hathaway states:

> Whilst it may be reasonable to attempt to use DWT to estimate unfranked dividends paid to non-residents, it is totally inappropriate to do so for franked dividends because it is not levied on those dividends.[144]

To support this notion, Hathaway cites the following from the Department of Treasury:

> Franked dividends attract no withholding tax.
>
> Withholding tax on unfranked dividends is 30 per cent. This reduces generally to 15 per cent in the case of double tax agreements (United States and United Kingdom resident companies may receive a rate of zero or 5 per cent of unfranked dividends received in some cases).[145]

Hathaway asserts that estimating unfranked dividends from DWT data is problematic because one must also know the corresponding mix of DWT rates that apply to the mix of different investors being considered.[146] Notwithstanding these difficulties in estimating the amount of unfranked dividends paid to non-resident investors, the estimation of franked dividends is extremely problematic as DWT is not levied on franked dividends paid to non-resident investors. Hathaway notes that in reproducing the method of H&M, the time series of unfranked and franked dividends paid to non-resident investors had been constructed using assumptions.[147] Hathaway notes that:

143 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, pp. 33–34.
144 Hathaway, *Comment on: A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 4.
145 http://comparativetaxation.treasury.gov.au/content/report/html/12_Chapter_10-03.asp
146 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 4.
147 ibid.

> Handley and Maheswaran have extensively constructed the data they analyse for the dividend and franking credit income of non-resident investors.[148]

Hathaway highlights that the estimation process of H&M is based on defining three types of non-resident investors with the following DWT characteristics.

Table 12.5 Handley and Maheswaran classes of non-resident investors

Type	Residency/ tax status	Description	DWT rate	Home tax rate	Population proportion
1	non-resident investor is tax exempt in its home country.	Pays no tax	0%	0%	10%
2	non-resident investor is (tax) domiciled in a country with which Australia has a double tax agreement (DTA) and Australian DWT is fully creditable against any home country personal tax liabilities.	Pays tax and gets a credit for tax paid in Australia	15%	15%	60%
3	non-resident investor is domiciled in a country with which Australia does not have a DTA and Australian DWT is not creditable against any home country personal tax liabilities.	Pay tax and gets no credit for tax paid in Australia	30%	15%	30%
	Weighted average DWT rate		12%		

Source: Adopted from Handley and Maheswaran[149]

Hathaway attempts to demonstrate that there is no direct link between DWT and franked dividends paid to non-residents. Furthermore, franked dividends paid to non-residents should not be estimated on the basis that there is a direct link. Hathaway notes that the weighted average DWT of 12 per cent is applied to the whole historical time period of DWT collections to estimate a series of unfranked dividends paid to non-resident investors. Beyond 2001, DWT ceased to be recorded as a separate item by the ATO and was included in the total of PAYG tax collection as part of the Simplified Imputation Tax System. DWT is only levied on unfranked dividends paid to non-residents, as full company tax is expected to have already been paid on franked dividends, with no further tax expected to be owed to the ATO.[150] The unfranked dividend series is then used to calculate franked dividends paid to non-resident investors, by using an assumed ratio of franked dividends to total dividends (across all investors).[151]

Hathaway concludes that:

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148 ibid., p. 6.

149 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 6.

150 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, pp. 6–7.

151 ibid., p. 8.

> …there is no formal connection between DWT and fully franked shares. The only connection presented between them was the assumed proportionate holding of franked shares by non-resident investors either 50% or 63%.[152]

Hathaway contends that H&M's estimated proportion of franking credits held by non-resident investors is “tantamount” to determining how those credits are valued by non-residents, and "[i]n effect, the authors indirectly assume their main results."[153]

The AER notes that the non-resident dividend and imputation credit data relied upon by H&M has been criticised by Hathaway as being predicated on contrived input parameters. The AER notes that the desired data concerning non-resident investors is not directly observable as it is not reported by the ATO. However, the AER also considers that H&M is a transparent study that discloses all the assumptions made to estimate data for non-resident investors.

The AER notes that H&M have justified each of the assumptions for the input parameters used in estimating the utilisation rate of non-resident investors. Furthermore, the AER considers each of the assumptions to be reasonable and consistent with the authors' definition of the utilisation rate as the incremental reduction in personal tax, if any, which arises from the receipt of a franked dividend compared to the receipt of an otherwise equivalent unfranked dividend - the after-company before-personal tax return to investors.[154] The nature and reasonableness of these assumptions are considered briefly here.

H&M measures the value of imputation credits to non-resident investors as the incremental saving in DWT from receiving franked rather than unfranked dividends. The utilisation rate is calculated as the incremental saving in DWT divided by the amount of Australian company tax paid. The utilisation rates are estimated from unfranked and franked dividends paid to non-resident investors. To illustrate, H&M reported the following worked example of their method to estimate the value of franking credits to non-resident investors:

[152] ibid., p. 18.
[153] Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 18.
[154] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 84.

Table 12.6 Handley and Maheswaran example estimation of value of franking credit for non-resident investors

Investor type	Type 1		Type 2		Type 3	
Dividend type	Unfranked	Franked	Unfranked	Franked	Unfranked	Franked
Australian resident company						
Gross dividend paid	64.00	64.00	64.00	64.00	64.00	64.00
– Australian DWT	0.00	0.00	9.60	0.00	19.20	0.00
Net dividend paid	64.00	64.00	54.40	64.00	44.80	64.00
Non-resident investor						
Dividend Received	64.00	64.00	54.40	64.00	44.80	64.00
– Home country tax payable	0.00	0.00	9.60	9.60	6.72	9.60
+ Credit for Australian DWT	0.00	0.00	9.60	0.00	0.00	0.00
After-tax return	64.00	64.00	54.40	54.40	38.08	54.40
Worldwide personal taxes						
Australia	0.00	0.00	9.60	0.00	19.20	0.00
Home country	0.00	0.00	0.00	9.60	6.72	9.60
Total	0.00	0.00	9.60	9.60	25.92	9.60
Incremental after-tax return		0.00		0.00		16.32
Incremental saving in net DWT		0.00		0.00		19.20
Underlying imputation credit		36.00		36.00		36.00
Utilisation rate		0.00		0.00		0.53

Source: Handley and Maheswaran[155]

Actual unfranked and franked dividend and imputation data relating to non-resident investors are not reported by the ATO and are therefore estimated by H&M using a set of assumptions. In particular, the following is assumed:

- The ratio of franked to total dividends
- DWT rates applied to foreign investors
- Decomposition of non-resident investor types

155 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 86.

Ratio of franked to total dividends

The ratio of franked to total dividends paid to non-residents is 63 per cent for 1991-2001 and 50 per cent for 1988-1990.[156] This assumption is made on the basis of taking total franked dividends paid by Australian companies minus the amount of resident individuals, funds, partnerships and trusts combined. The balance represents the total amount of franked dividends paid to non-resident investors, life assurance companies, other companies and any tax exempt entities. H&M note that it is not possible to disaggregate this remaining balance between the outstanding investor groups and therefore use this remaining balance to estimate franked to total dividends paid to non-resident investors. Over the period 1991-2001, this ratio averaged 63 per cent, and 1988-1990 Handley and Maheswaran assume a lower ratio of 50 per cent on the basis that this period was prior to the introduction of anti-dividend streaming rules in 1990, which restricted the payout of franked dividends to non-resident investors.[157] Since 2002 (introduction of the simplified taxation system) DWT has not been separately disclosed by the ATO. Therefore, H&M estimate that non-residents received 25 per cent of total dividends paid to individuals, funds, trust and partnerships and non-residents each year, of which 63 per cent are franked.[158] These estimated percentage figures are justified by data from the earlier 1991–2001 period i.e. where non-residents receive 25 per cent of total dividends paid in each year, of which 63 per cent are franked.[159]

DWT rates applied to foreign investors

The DWT rates assumed by H&M to be levied on types 1, 2 and 3 non-resident investors is 0, 15 and 30 per cent respectively. The DWT rates have been justified by referencing DWT rates published by the ATO, Australian Master Tax Guide and Department of Treasury.[160]

Decomposition of non-resident investor types

The ratio of type 2 to type 3 non-resident investors and type 1 to type 2 investors is also estimated to calculate the relative level of dividends paid to each type of non-resident investor.[161] This ratio is calculated on the basis of 10 years data sourced from the ABS, which presents the relative investment in Australian equities by each of type 1, 2 and 3 non-resident investors. Specifically, the ABS presents data on Australia's international investment position by selected countries. It is observed from the ABS statistics that on average over the period 1992-2001, 89 per cent of total foreign investment was attributable to OECD countries and 29 per cent of on average was attributable from portfolio investors from the USA and UK. Handley notes that this ABS data suggested that about 30 per cent came from portfolio investors from the UK and USA and so H&M assume 30 per cent of non-resident investors are type one investors. The ABS data also suggests that about 10 per cent of investment by non-

[156] ibid., p. 87.

[157] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, pp. 87–88.

[158] ibid., p. 88.

[159] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 25.

[160] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 25 see – Australian Taxation Office, 2006, Taxation Statistics 2003–2004, Commonwealth of Australia, p. 143; CCH Australia, 2004, Australian Master Tax Guide, para 22-010; Department of Treasury http://www.treasury.gov.au/contentitem.asp?pageId=&ContentID=625; Bodie, Z., A. Kane and A.J. Marcus, *Investments 8th edition*, 2009, p. 100.

[161] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 87.

residents came from non-OECD countries. Furthermore, non-OECD countries are most likely to be tax-havens that do not have a DTA with Australia and so H&M assume type 3 non-resident investors represent 10 per cent of non-resident investors.[162] Finally, the remaining balance of 60 per cent is attributable to type 2 non-resident investors. Handley notes that it is with the DWT rates of 0, 15 and 30 per cent applied to type 1, 2 and 3 non-resident investors respectively that Hathaway concludes H&M assume a constant weighted average DWT rate of 12 per cent.[163] H&M note the limitation expressed by the ABS that it is difficult to determine the non-resident portion of investors in Australia and state:

> The limitation expressed by the Australian Bureau of Statistics, that it is inherently difficult to estimate the precise nature of non-resident equity investment in Australia because where nominees are involved, the issuer generally does not know who holds the share.[164]

Additionally, Handley notes that the limitation identified by the ABS would still arise even if one had access to the share registries of each firm.[165]

Post-2000 data issues

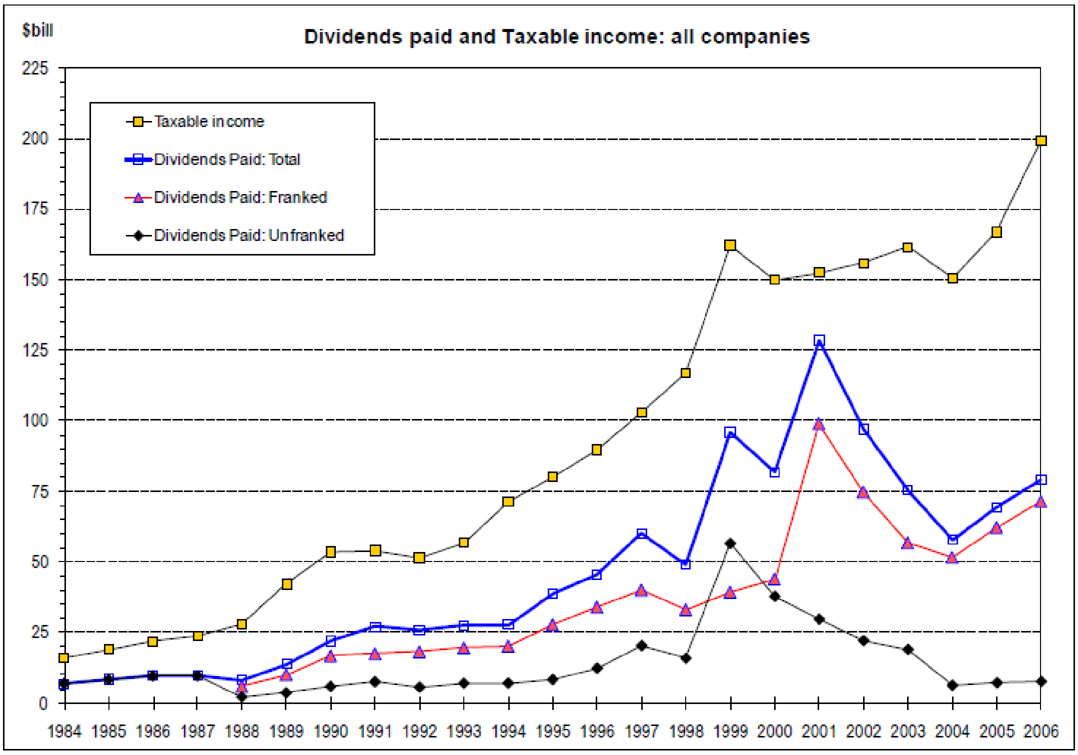
Hathaway asserts that H&M ignores investors' response to the abolishment of the inter-corporate dividend rebate by smoothing the material spike in franking credits over the period 2000–01. Hathaway also asserts that the average results for 2001-2004 inappropriately include data across periods of different tax regimes. In particular, the introduction of the Simplified Imputation System from 1 July 2002 and the old imputation tax system prior to this.

Hathaway acknowledged the figure below and noted:

> There are two obvious features here: the spike in unfranked dividends following the announcement of the abolition of the inter-corporate dividend rebate and the overall decline in total dividends, both franked and unfranked, after 2002. The spike is due to companies re-arranging their affairs ahead of the formal commencement date for the consolidation regime and the abolition of the inter-corporate dividend rebate. The apparent decline in the overall level of dividends just reflects the substantial reduction in double counting of dividends within consolidated groups. Previously they all reported separately which meant the same dividend flow was being counted multiple times.[166]

162 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 26.
163 ibid.
164 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 88.
165 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 26.
166 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 10.

Figure 12.2 Dividends paid by all Australian companies



Source: Hathaway[167]

Hathaway makes the observation that this reflects a substantial reduction in the amount of dividends measured. In particular, where a company pays a dividend to an unrelated party which in turn pays that income out as a dividend, that dividend would be counted multiple times. Hathaway claims that the H&M data eliminates the large swings in franked and unfranked dividends by:

- smoothing the material spike in 2000 and 2001
- applying "smooth factors" by assuming a 12 per cent DWT and a proportion of 50 or 63 per cent for over the whole period (1988-2004)

[167] Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 10.

In summary, Hathaway concludes:

> The Handley and Maheswaran data series of franked and unfranked dividend income attributed to non-residents is just a series of DWT with two very smooth (almost constant) factors applied to it.[168]

Handley considers that the introduction of the Simplified Imputation System was essentially mechanical in nature and not likely to bear any material impact on the results of H&M. Handley notes the following from the ATO to support this notion:

> The system is largely unchanged for individuals who receive franked dividends…The simplified imputation system generally provides the same outcomes as the previous system, but changed the mechanics of the former system to provide simpler reporting rules; increased flexibility in franking distributions; and consistency of treatment across entities receiving franked dividends.[169]

Regarding the smoothing of data, Handley notes that H&M takes a simple average of DWT amounts for 2000 and 2001 to smooth the reported DWT over the two year period.[170] Additionally, Handley notes that this smoothing adjustment is highly unlikely to have had any material impact on the results of estimated utilisation rates by H&M, which span seventeen years of data.[171] The AER concurs with this view.

Double counting of franking credits

Hathaway notes that including franking credit totals data from Trusts and Partnerships would result in a double-counting of franking credits. While Hathaway's argument is not clear, he seems to suggest that this may overstate the value of imputation credits estimated by H&M. This is because the dividends would flow back to the issuing companies and be recounted in Trusts and Partnerships reported figures of unfranked and franked dividends. Hathaway points out that H&M include dividend data from partnerships and trusts in table 3 of their analysis, which is reproduced below.[172]

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168 ibid., p. 11.
169 Australian Taxation Office, *Imputation reference guide*, 2006, p. 5.
170 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 83.
171 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 27.
172 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 12.

Table 12.7 Aggregate dividends received by resident and non-resident investors

Utilisation rate	'90	'91	'92	'93	'94	'95	'96	'97	'98	'99	'00	'01	'02	'03	'04	Mean '90–'00	Mean '01–'04
Individuals	1.8	1.9	1.8	2.1	2.5	3.8	4.4	4.6	5.2	5.6	6.7	8.8	7.7	9.4	11	3.7	9.2
Funds	0.7	0.6	0.7	0.7	0.9	1	1.7	1.8	2	2.1	2.2	2.8	2.5	2.7	3.7	1.3	2.9
Trusts	0.4	0.3	0.6	0.8	1	1.9	2.4	2.5	2.8	3.5	5	5.6	5.6	7.1	9.2	1.9	6.9
Partnerships	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.2
Non-residents	1	1.5	0.7	1.2	1.2	1.6	2.2	2.3	2.5	2.2	3.2	3.2	3.7	4.4	5.4	1.8	4.2
Total	3.9	4.4	3.8	5	5.6	8.3	10.8	11.3	12.7	13.5	17.1	20.6	19.5	23.8	29.5	8.8	23.4

Source: Handley and Maheswaran[173]

Hathaway states that H&M:

> …cannot just add data for [partnerships and trusts] along with Individuals, Funds, and Non-residents as it overestimates the indirect income to these three groups. It assumes that all of the [partnerships and trusts] income can be treated as indirect income when in practice much of it returns to companies so it is a circular flow. [174]

The AER considers that Hathaway overstates the issue of double counting on H&M's analysis. Handley acknowledges that the inclusion of dividends received by Partnerships and Trusts would likely flow back to companies, however points out that it is the results from H&M's table 4 that have been used for estimating the utilisation of imputation credits, which excludes Partnerships and Trusts.[175] Furthermore, Handley adds that H&M estimate of the average utilisation rate of imputation credits is based only on credits received and used by the ultimate end investor. Accordingly, H&M's utilisation estimates do not include credits received by pass-through investors such as Partnerships and Trusts. Finally, by excluding pass-through investors from the calculations, H&M avoid any double counting problem that would otherwise arise as dividends are paid along chains of interposed entities that exist within the same corporate structure.[176] Hence Hathaway's arguments about double counting have no bearing on the theta estimates derived from the H&M study.

Missing data

Hathaway notes that H&M does not include franking credit data for superannuation funds operated by life assurance companies and tax-exempt entities. Although not explicit, Hathaway suggests that the utilisation rate is understated by the absence of life assurance businesses redemption data. To this end, it appears Hathaway makes this point in the process of trying to establish that the H&M data set is incomplete. Hathaway cited the following from H&M:

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173 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation*, 2008, p. 89.
174 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 12.
175 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 28.
176 ibid.

> We note that, due to a lack of data, our estimates do not include superannuation funds operated by life assurance companies (for which imputation credits are valuable) but also our estimates do not include tax-exempt entities, such as State government and educational, religious and community service organisations (to whom imputation credits are of no value).[177]

Hathaway asserts that the authors have implied that the two neglected data sets may be (at least partially) offsetting, and disagrees with this notion, on the basis that Life Office claims are much bigger than the tax exempt entities redeeming credit via a refund.[178] Furthermore, Hathaway contends that although franking credit data is not reported by the ATO, it may be estimated from funds data. Specifically, Hathaway noted:

> it is reasonable to assume that Life Office superannuation businesses will have the same allocation as funds to franked and unfranked Australian shares. The data on funds can be used as source of Life Office estimates of redemption of franking credits.[179]

Hathaway also asserts that H&M ignored the franking credit data relating to tax-exempt investors, despite the fact that these investors are able to claim credits as cash. Hathaway also notes that State Government enterprises cannot offset income against credits and this data should therefore not be excluded in H&M's analysis.[180]

Hathaway contends that the Life Offices have a similar allocation of funds to Australian equities as do funds that report to the ATO. As such, Hathaway suggests that data on funds can be used to estimate Life Office dividend and imputation redemption data.[181] Hathaway also claims that H&M are under the misapprehension that State Government enterprises can claim credits as tax exempts.[182]

Although the issue of missing data has been acknowledged by H&M, it still remains as a basic problem for the tax study. In particular, Hathaway highlights the absence of redemption statistics for Life Offices, despite the fact that they are able to redeem franking credits as if superannuation funds. Similarly, Hathaway notes that some tax-exempt entities are able to redeem franking credits as refunds, but franking credit data on these entities is also ignored.[183]

The AER accepts that the H&M has some missing data, but also notes that this limitation is disclosed by the authors of the study. Handley also notes the effect on the results on H&M:

> Their [Handley and Maheswaran] estimate of the average utilisation value of franking credits is understated by the extent to which credits received and redeemed by superannuation funds operated by life assurance companies have not been included, but on the flip-side, that their estimate of the average utilisation value of franking credits is overstated by the extent to

177 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation*, 2008, p. 88.
178 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 14.
179 ibid.
180 ibid.
181 ibid.
182 ibid.
183 ibid.

> which credits received and cannot be redeemed by State Governments and other similar tax exempts have not been included.[184]

Handley notes that Hathaway does not acknowledge there is an offset between including life office and State Government redemption statistics. Whilst Hathaway proposes a method to estimate the credits received by Life Office businesses, he does not present any corresponding data to estimate credits received by State Governments. As such, Handley considers that Hathaway provides no evidence to substantiate the claim that H&M's results are biased as the omitted Life Office redemption rates would outweigh the credits unable to be redeemed by State Governments. Finally, Handley notes:

> The bias that Hathaway alludes to would mean that H&M's estimates of the utilisation rate of imputation credits is understated (since Hathaway appears to suggest that the amount of credits received by Life Offices would dwarf the amount of credits received by State Government enterprises).[185]

The AER acknowledges the limitations in the H&M data set which arise as a result of lax reporting requirements for dividend and imputation credit data by the ATO in respect of Life Office companies.

Comparing franked and unfranked dividends

Hathaway asserts that H&M have incorrectly conducted their analysis in calculating the utilisation of imputation credits by type 3 non-resident investors. H&M calculates the utilisation rate by comparing $64 of franked and unfranked dividends to calculate the incremental DWT saving to non-resident investors. H&M state their measurement approach:

> We define this utilisation value as the incremental reduction in personal tax, if any, which arises from the receipt of a franked dividend compared to the receipt of an otherwise equivalent unfranked dividend. This value will vary according to the tax status and domicile of the investor.[186]

Accordingly, H&M compare $64 of franked and unfranked dividends to calculate the incremental saving of DWT expressed as a percentage of corporate tax paid for both types of dividends. Hathaway claims that this is not comparing like-with-like - the franked $64 dividend already has $36 company tax paid but the unfranked dividend does not. Hathaway illustrates this point with the following table:

[184] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 29.
[185] ibid., p. 30.
[186] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 84.

Table 12.8 Hathaway type 3 non-resident investor utilisation of credits

	Unfranked	Franked
Company profit	$100	$100
Company tax	$0	$36
Dividend	$100	$64
Franking credit	$0	$36
DWT	$30	$0
Net income	$70	$64
Home tax	$10.50	$9.60
After–personal tax income	$59.50	$54.40
World–wide personal taxes		
Australia	$30	$36
Home	$10.50	$9.60
Total	$40.50	$45.60
Incremental saving in net DWT		–$6.00
Incremental after–tax return		–$5.10
Utilisation of the credit		–16.67% (–$6/$36)

Source: Hathaway[187]

Hathaway's analysis begins with the same level of company profit paid out, then assesses the difference with between unfranked and franked dividends, taking into account the level of Australian company tax paid. Hathaway notes:

> If company tax is meant to just be a withholding of personal tax under an imputation tax system, then to ignore company tax payments amounts to ignoring a substantial and ultimately personal tax. This renders invalid after-personal tax comparisons when such a substantial amount of personal tax is ignored.[188]

Hathaway's analysis demonstrates that a non-resident type 3 investor who receive a franked rather than unfranked dividend, would make a $6 after-company, after-

187 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 16.
188 ibid.

personal tax loss, once company tax is accounted for. Accordingly, Hathaway estimates the utilisation rate of a type 3 non-resident investor as -16.67 per cent.[189]

This contrasts with H&M's approach which is outlined in the table below:

Table 12.9 Handley and Maheswaran example estimation of value of franking credit for non-resident investors

Investor type		**Type 1**		**Type 2**		**Type 3**
Dividend type	Unfranked	Franked	Unfranked	Franked	Unfranked	Franked
Australian resident company						
Gross dividend paid	64.00	64.00	64.00	64.00	64.00	64.00
– Australian DWT	0.00	0.00	9.60	0.00	19.20	0.00
Net dividend paid	64.00	64.00	54.40	64.00	44.80	64.00
Non-resident investor						
Dividend Received	64.00	64.00	54.40	64.00	44.80	64.00
– Home country tax payable	0.00	0.00	9.60	9.60	6.72	9.60
+ Credit for Australian DWT	0.00	0.00	9.60	0.00	0.00	0.00
After-tax return	64.00	64.00	54.40	54.40	38.08	54.40
Worldwide personal taxes						
Australia	0.00	0.00	9.60	0.00	19.20	0.00
Home country	0.00	0.00	0.00	9.60	6.72	9.60
Total	0.00	0.00	9.60	9.60	25.92	9.60
Incremental after-tax return		0.00		0.00		16.32
Incremental saving in net DWT		0.00		0.00		19.20
Underlying imputation credit		36.00		36.00		36.00
Utilisation rate		0.00		0.00		0.53

Source: Handley and Maheswaran[190]

H&M assume an Australian corporate tax rate of 36 per cent, a DWT of 30 per cent and a home tax rate of 15 per cent for the type 3 non-resident. This analysis implies a

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[189] ibid.

[190] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 86.

utilisation for the underlying imputation credit of 53 per cent for type 3 non-resident investors.[191] Hathaway interprets the result of H&M as follows:

> Recall from above that a Type III non-resident investor is one that pays tax in their home country and gets no tax credit for any tax paid in Australia – paradoxically they get no credit for any DWT levied in Australia on their unfranked dividends yet they are meant to be the one group that can utilise the franking credits on their franked dividends.[192]

Finally, Hathaway concludes that the problem with using numbers for examples such as the above from H&M is that the answer is an artefact of the assumed input data.[193]

Hathaway disputes the method by which H&M estimate the utilisation rate for non-resident investors. Hathaway notes that comparing unfranked and franked dividends of the same amount, to calculate the after-tax returns and the utilisation rate of credits for non-resident investors is flawed. In particular, this sort of comparison effectively ignores the effect of company tax payments on non-resident investor returns. Hathaway contends the non-resident utilisation result of Handley and Maheswaran (2008) was perverse, as the only class of non-resident investor that can utilise franking credits are those that get no credit for any tax paid in Australia on their unfranked dividends.

The AER notes that the conclusion from the results of H&M is not inconsistent with its definition of utilisation rates for non-resident investors. By contrast, Hathaway's alternative analysis is inconsistent with the definition of utilisation rate given by H&M and is therefore not a valid criticism in the AER's view.

To reiterate, Handley notes that the definition of the utilisation value of a franking credit to non-residents is the incremental reduction in (worldwide) personal taxes that arise from the receipt of a franked, rather than an equivalent unfranked dividend.[194] That is, the extent to which credits generated for the payment of Australian corporate tax can be used to offset against personal taxes.[195] Handley acknowledges the difficulty in determining the value of an imputation credit for a non-resident investor, as one must consider the non-resident's Australian withholding tax liabilities, its home country personal tax liabilities and whether these two items interact. It is for this reason that H&M considered the utilisation value of a credit as an incremental reduction in worldwide rather than just domestic taxes.[196] For this comparison, all other factors are held constant, so the appropriate dividends to be compared are the franked and unfranked dividends of the same amount. Handley notes:

> The different after-tax returns that Hathaway refers to, represents the value of the distributed franking credits, because all else has been held constant from the investor's perspective.[197]

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[191] ibid.
[192] Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 16.
[193] ibid.
[194] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 32.
[195] ibid.
[196] ibid. – see footnote 60.
[197] ibid.

Hathaway's observation is that company and personal taxes are partially integrated under an imputation tax system would only apply to domestic investors. Handley considers that if one was to take into account Australian corporate tax, it follows that all worldwide corporate taxes should be factored into the analysis and this would distort the value of the after-company (Australian) tax before-personal tax return under an Australian imputation system. This is explained further by Handley who notes:

> presumably the unfranked $100 dividend is paid out of profits which have not been subject to Australian corporate tax because those profits have already been subject to some foreign corporate tax – but regardless, this is a different question to the one considered by H&M.

Finally, the AER considers that the utilisation rate of 0.05 for non-resident investors over the period 1990-2004 should not be surprising because imputation credits paid to the majority of non-resident (type 2 and 3) investors are considered worthless by H&M.[198]

Excess credits 1990-2000

Hathaway notes that the utilisation of franking credits by resident investors is not directly observable from ATO data. Accordingly, Hathaway contends that this series of franking credit data has been calculated on the basis of H&M's own estimates.

Although not clear about how this impacts H&M's utilisation estimate, Hathaway argues:

> …that there is no justification presented for their estimates unutilised credits so it is impossible to appraise their utilisation rate.[199]

More specifically, Hathaway notes that the ATO data depicts declared credit income as the same number as credits claimed – so any estimate of under utilised credits will depend on the estimates of individuals' net tax liability, with and without the franking credits. Hathaway concludes that H&M have not attempted to explain their estimates of individuals' estimates of net tax liabilities.

Hathaway identified a series of excess credits reported in table 4 of Handley and Maheswaran (2008) and asserts that these figures are not published by the ATO, and are based on an unspecified calculation by the authors.[200] Hathaway contends that one cannot appraise the utilisation rate estimates of Handley and Maheswaran (2008), in light of the unjustified series of excess credits.[201]

The AER notes that the excess credit series is explained in H&M and that Hathaway's evaluation of this data appears incorrect. H&M define excess credits as the aggregate amount of imputation credits not used by investors to reduce their personal tax liabilities.[202] Additionally, it is noted by Handley that H&M take into account

198 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 91.

199 Hathaway, *A measure of the Efficacy of the Australian Imputation Tax System*, July 2010, p. 19.

200 ibid., p. 13.

201 ibid., p. 19.

202 Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 85.

imputation credits received both directly by investors (primary credits) and indirectly through distributions from Partnerships and Trusts (subsidiary credits).[203] H&M note the following assumptions relating to credits used and credits received:

- Resident Individuals — 'credits used' represent the franking rebate allowed net of all other rebates. Credits used are therefore estimated as the greater of total rebates allowed less the sum of all other rebates claimed and zero. 'Credits received' are equal to the sum of primary and subsidiary imputation credits by the taxpayer and included in taxable income.[204] It does not appear that H&M have made assumptions in estimating credits received and used for the period prior to 2000. The assumption of full utilisation of credits beyond the year 2000 is consistent with the full cash rebate for excess credits and investor rationality.

- Resident funds — 'credits used' is defined as the greater of total rebates allowed less foreign tax credits claimed and zero. Foreign tax credits data is available from 1998 and estimates prior to that are based on the level of net foreign income. Total rebates allowed by the ATO are equal to gross tax payable less net tax payable.[205] 'Credits received' are primary imputation credits received each year, which were calculated based upon the available unfranked and franked dividend data available each year.[206] In 1989, primary credits were reported but subsidiary credits were not. So based on available data from 2001–2004, 70 per cent of total credits were considered to be primary credits. For 1990–2000 only gross dividends received were reported and an 85 per cent ratio of franked to total dividends based on data for 2001–2004.[207] For the post-2000 period, it is clear that excess credits are calculated as zero. The assumption of full utilisation of credits beyond the year 2000 is consistent with the full cash rebate for excess credits and investor rationality.

- Non-residents — 'credits received' are equal to the amount of imputation credits underlying the franked dividends paid to non-resident investor types 1, 2 and 3, and the corresponding amount of Australian DWT by type 3 non-residents.[208] As noted above, the AER considers H&M's assumptions regarding non-resident investors to be reasonable.

12.6.4.5 AER conclusion

The AER acknowledges the limitations of the tax study conducted by H&M noting that the study is transparent and freely discloses the assumptions made in the analysis. The AER considers the informative value of the study outweighs the data limitations and that the assumptions made by H&M are reasonable in light of the limited data provided by the ATO. Finally, the AER maintains that utilisation rate estimated from H&M for the period 2001–04 should still be used to as an upper bound estimate of theta for the post July 2000 period.

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[203] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 31.
[204] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 85.
[205] ibid., p. 87.
[206] ibid., p. 86-87.
[207] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 31.
[208] Handley and Maheswaran, *A measure of the Efficacy of the Australian Imputation Tax System*, 2008, p. 88.

For the reasons outlined above, the AER considers that based on the material currently available, the adoption of the utilisation rate of 0.74 is a conservative approach to incorporating information from tax statistics given the assumptions made by H&M and the time value loss of money associated with receiving and utilising imputation credits.

12.6.5 Miscellaneous gamma issues

12.6.5.1 AER draft decision

In the draft decision, the AER maintained the position from the SORI that the estimation of Beggs and Skeels (2006) dividend drop-off study, which valued $1 of cash dividends at $0.80. The AER maintained an MRP estimate based upon a full value of cash dividends. Finally, the AER maintained its position from the SORI that the appropriate value of gamma was 0.65.

12.6.5.2 Victorian DNSP revised regulatory proposals

In their revised proposals, the Victorian DNSPs and their consultant (SFG) raised a number of miscellaneous issues in relation to:

- inconsistencies about how cash dividends are valued in different parts of the AER's analysis
- a practitioner method to check the reasonableness of the AER's gamma estimate.

Averaging results of Tax and dividend drop-off studies

The Victorian DNSPs contended that the AER's approach to estimating theta is methodologically flawed, as it takes an average of a point estimate (from the dividend drop-off study by Beggs and Skeels) and an upper bound estimate (from H&M tax statistics study). JEN notes that taking an averaging approach of these two sources implies that the AER's estimate of theta will be upwardly biased.[209]

Inconsistency in the value of cash dividends

SP AusNet noted that the AER has failed to address two inconsistent assumptions made about the value of cash dividends, when deriving the cost of capital. Specifically, that the AER's estimate of theta from the Beggs and Skeels dividend drop-off study estimates the value of cash dividends as $0.8 value per dollar.[210] Conversely, SP AusNet noted that when estimating the return on equity using the CAPM, an assumption is made about cash dividends being valued at 100 cents in the dollar.

SP AusNet contended that it is incorrect and materially inconsistent to use two different values for the same parameter when estimating the return on capital. Additionally, SP AusNet noted that the Australian Competition Tribunal has previously recognised the importance of maintaining the mathematical integrity of the CAPM when estimating the WACC in the GasNet decision.[211]

[209] JEN, *Revised regulatory proposal*, p. 261.
[210] SP AusNet, *Revised regulatory proposal*, p. 342.
[211] ibid.

Practitioner approach to check the reasonableness of the AER's gamma estimate

SFG on behalf of the Victorian DNSPs contended that the practitioner approach be used as a reasonableness check of the AER's estimate of gamma. SFG contended that comparing the AER's cost of equity using the practitioner approach against the AER's conventional cost of equity implies that the AER's estimate of gamma is substantially higher than that estimate implied by market practice. The practitioner approach defines the cost of equity as the following:[212]

$$r_e^* = r_f + \beta_e^* \times MRP^*$$

Where the MRP and βe are based on returns from dividends and capital gains only - effectively subtracting the value of imputation credits. The grossed-up cost of equity that includes the value of imputation credits is defined as follows:[213]

$$r_e = r_f + \beta_e \times MRP$$

SFG contended that the practitioner cost of equity may also be estimated by applying the following adjustment factor to the grossed-up cost of equity.[214]

$$r_e^* = r_e \frac{1-T}{1-T(1-\gamma)}$$

On this basis, SFG first calculated the grossed-up cost of equity using the input parameters specified in the AER's QLD final distribution decision. This grossed-up cost of equity is then adjusted by the adjustment factor (using the AER's estimate of 0.65 for gamma) to calculate the practitioner cost of equity. This is compared to the alternative estimation of the practitioner cost of equity estimate. The alternative cost of equity is estimated by subtracting an assumed value of 0.5 per cent for imputation credits from the AER's MRP estimate of 6.5 per cent. The resulting value of 6 per cent for the MRP is used in conjunction with the cost of equity input parameters used in the AER's QLD draft determination. These steps are outlined as follows:[215]

Step 1 - calculating the grossed-up cost of equity using AER inputs

$$\begin{aligned} r_e &= r_f + \beta_e \times MRP \\ &= 5.64\% + 0.8 \times 6.5\% \\ &= 10.84\% \end{aligned}$$

Step 2 - calculating cost of equity using the practitioner approach factor adjustment

[212] SFG, *Issues related to estimating gamma*, July 2010, p. 32.
[213] ibid.
[214] ibid.
[215] SFG, *Issues related to estimating gamma*, July 2010, p. 32–33.

$$r_e^* = r_e \frac{1-T}{1-T(1-\gamma)}$$

$$= 10.84\% \frac{1-0.3}{1-0.3(1-0.65)}$$

$$= 8.47\%$$

The 8.47 per cent cost of equity under the practitioner approach is compared against the practitioner approach which subtracts the value of imputation credits from the MRP to estimate the cost of equity.[216]

$$r_e^* = r_f + \beta_e^* \times MRP^*$$

$$= 5.64\% + 0.8 \times 6.0\%$$

$$= 10.44\%$$

SFG noted that the practitioner's cost of equity estimate using the AER's 0.65 value of gamma understates the cost of equity compared to the practitioner's estimate with the value of imputation credits subtracted from the MRP. Accordingly, SFG observed that a gamma estimate of 0.09 would be required for the cost of equity calculation to be consistent with market practice.[217]

12.6.5.3 Issues and AER considerations

Averaging results of Tax and dividend drop-off studies

The AER acknowledges that tax estimates represent a reasonable theoretical upper bound for the value of theta and also notes that estimates of theta implied from dividend drop-off studies should be treated with caution as they are affected by noise in the underlying data.[218] As noted above, the AER has not simply taken the maximum theta value implied by the Handley and Maheswaran study in estimating theta. In recognising the reasons why this would be a maximum value, the AER's estimate of utilisation rate derived from tax statistics accounts for the time value of money.

The AER acknowledges, as it did in the WACC review, that the question of weighting empirical estimates from tax statistics and dividend drop off studies therefore becomes relevant. In this regard, the AER maintains its position from the SORI that:

> The AER considers that for the purposes of this final decision it is reasonable to apply equal weight to each of the estimation methodologies, and round to the nearest 0.05 to generate a point estimate. This reflects the AER's view that the results provided by each of the two methodologies are somewhat uncertain in terms of providing a point estimate, but that it is reasonable to regard them as providing bounds on a range for gamma.[219]

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216 ibid., p. 33
217 ibid.
218 AER, *Final decision, WACC parameters*, May 2009, pp. 467–468.
219 ibid., p. 468.

Inconsistency in the value of cash dividends

The AER does not consider that the value of cash dividends has been inconsistently applied across CAPM and dividend drop-off models. Rather, the AER considers that the value of cash dividends has been estimated consistently with the assumptions underlying each of the models. The AER acknowledges Handley's following comments:

> regression coefficients from dividend drop-off studies not only reflect the value of a dollar of franking credits and the value of a dollar of cash dividend but also reflect the impact of the differential personal taxes and risk.[220]

Furthermore, Handley considered that the regression coefficient of 0.8 reflects a 20 per cent adjustment due to the difference in personal taxes and risk. The regression coefficient does not represent the after-company-before-personal tax value of one dollar of cash dividends if risk and differential taxes are important. In addition, Handley notes:

> it is only if there are no differential taxes and risk involved in trading around the ex-dividend date, or one assumes them away, that the coefficient can validly be interpreted as the after-company-before-personal tax value of one dollar of dividends.[221]

The AER considers that the Beggs and Skeels (2006) 0.8 estimate of a dollar of cash dividends is consistent with the theory underlying dividend drop-off studies. This was acknowledged in the AER's QLD final distribution determination in advice given by Handley that:[222]

- Boyd and Jagganathan (1994) rely substantially on arbitrage arguments (in addition to equilibrium considerations) and therefore the results of the paper should be interpreted with caution

- only a small subset (5 per cent) of stocks analysed by Graham, Michaely and Roberts (2003) provide an estimate where a dollar of cash dividends is valued at 100 cents. When the full sample of stocks is used, a dollar of cash dividend is valued at less than 100 cents.

Practitioner approach to check the reasonableness of the AER's gamma estimate

The AER does not accept that SFG's use of the practitioner approach is valid to check the reasonableness of the AER's gamma estimate. The AER notes Handley's advice which considers that SFG's application of the Officer 1994 WACC framework is inconsistent with the perpetuity assumption underlying the model. Specifically, SFG's assertion that the grossed-up rates of return consist of three components: capital gains, dividends and the value of franking credits. Handley noted:

> …the Officer (1994) model is a perpetuity model – this means that grossed-up rates of return consist of only two components: dividends and the value of franking credits – i.e. there are no capital gains. This means that SFG's

[220] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 31.
[221] ibid., p. 32.
[222] AER, *South Australian distribution determination*, Final decision, May 2010, p. 155.

> “Adjustment Step”, made in accordance with the Officer model (1994) strictly only applies in a perpetuity model.[223]

Handley concluded that SFG's report does not demonstrate the difference between the AER's estimate of the conventional cost of equity and that of practitioners. Rather, the source of the difference for cost of equity estimates used by SFG lies in the fact that the perpetuity assumption holds in the Officer model but does not hold in practice.[224]

On a minor point, the AER also notes that SFG's reduction to the MRP back to 6 per cent in its calculation to account for the utilisation rate is not correct. The AER increased the MRP to 6.5 per cent in the WACC review largely because of the GFC.

12.6.5.4 AER conclusion

The AER concludes that the estimate of cash dividends from Beggs and Skeels (2006) is consistent with the theory underlying dividend drop-off studies. The AER also concludes that the analysis provided by SFG does not provide a valid cross check of the AER's gamma estimate.

12.7 AER conclusion

In accordance with clause 6.12.1 (7) of the NER, the AER's decision on the estimate cost of corporate income tax is set out below.

The AER has estimated the corporate income tax allowance for each DNSP for the forthcoming regulatory period in accordance with the formula set out in clauses 6.5.3, 11.17.2 and other relevant provisions including clauses 6.5.4(g) and (h) of the NER.

The AER has adopted the tax depreciation calculations in the DNSPs' revised proposals, as being reflective of recent amendments to tax legislation affecting diminishing value rates used for tax depreciation as allowed under clause 11.17.2(c). The AER has also determined a corporate income tax rate of 30 per cent over the forthcoming regulatory control period.

With respect to gamma, the AER considers that there is now persuasive evidence justifying a departure from the value of 0.65 set in the SORI in respect of the payout ratio aspect of gamma.

In deciding whether a departure from value of gamma set in the SORI is justified, the AER must consider 'the underlying criteria' and whether, in the light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes that value inappropriate.[225]

As outlined in the draft decision, the underlying criteria used by the AER in its SORI in relation to gamma are:

- the need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services

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[223] Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010,pp. 35–36.

[224] ibid.,,p. 36.

[225] NER, cl. 6.5.4(h).

- the need to achieve an outcome that is consistent with the national electricity objective
- the need for persuasive evidence before adopting a value or method that differs from the value or method previously adopted, and
- the relevant revenue and pricing principles, which are:
  - providing a service provider with a reasonable opportunity to recover at least the efficient costs
  - providing a service provider with effective incentives in order to promote efficient investment, and
- having regard to the economic costs and risks of the potential for under and over investment.[226]

In departing from the gamma value set in the SORI, the AER must demonstrate, in its reasons for the departure, that the departure is justified on the basis of the underlying criteria.[227] The AER's reasons and justifications are as follows:

- the true value of the payout ratio, for the purposes of the "traditional" approach to calculating gamma, is within a range of 70 to 100 per cent
- empirical evidence suggests the average payout ratio is approximately 70 per cent, however there are strong theoretical grounds to suggest that retained credits have some value
- given the material currently available, the AER considers that for the distribution determinations for the Victorian DNSPs, the theta value of 0.65 is still a reasonable approximation given the uncertainty about empirical evidence from dividend drop-off studies and tax statistics.
- when two extreme values for the payout ratio (70 per cent and 100 per cent) are combined with a theta of 0.65, the range for gamma becomes 0.465 to 0.65
- given the inherent uncertainty in the estimation of theta, the AER considers that a departure from the gamma value of 0.65 adopted in the SORI and the adoption of a gamma of 0.5 is justified on the basis of the underlying criteria, in particular the need to provide DNSPs with a reasonable opportunity to recover at least their efficient costs.

The value of the tax building block for this final decision, as presented in table 3, has also been affected by changes arising from other areas of the AER's draft decision, particularly in relation to capital expenditure but various other factors affecting forecast taxable income.

226 NER, cl. 6.5.4(e); and NEL, section 7A.
227 NER, cl. 6.5.4(i)(2).

Table 12.10 AER conclusion on corporate income tax liability ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	6.3	6.7	7.4	7.7	8.4
Powercor	12.5	12.9	14.1	15.0	16.4
JEN	2.9	3.4	4.4	5.5	5.9
SP AusNet	11.1	2.9	5.1	4.2	3.9
United Energy	8.5	8.8	9.8	11.7	13.5

13 Efficiency carryover amounts for 2006–10

This chapter outlines the AER's calculations of the revenue increments or decrements for each year of the 2011–15 regulatory control period arising from the application of the Essential Services Commission of Victoria's (ESCV) efficiency carryover mechanism (ECM) during the current regulatory period of 2006–10. The ECM was first introduced by ESCV's predecessor, the Office of the Regulator General (ORG) in the price review for 2001–05 as part of the regulatory framework for prescribed distribution services.

Under the ECM, Victorian DNSPs are awarded (penalised) for efficiency gains (losses) achieved against the expenditure forecasts in one regulatory period, which they are allowed to carry over into the next regulatory control period. These gains (losses) are carried over in the form of an addition to (subtraction from) the building block revenue requirements built for the forthcoming regulatory control period, to reflect the efficiency gains earned (losses made) in the previous period.[1]

As indicated in its decision to develop and apply an efficiency benefit sharing scheme (EBSS), the AER recognises that efficiency carryover schemes are currently operating in some jurisdictions, such as the ECM in Victoria. The AER has calculated and applied carryover amounts for the Victorian DNSPs in accordance with the ESCV's existing scheme, in the AER's regulatory determinations for the 2011–15 regulatory control period.

13.1 Regulatory requirements

Clause 6.4.3(a)(5) of the *National Electricity Rules* (NER) provides for a building block determination to include:

> the revenue increments or decrements (if any) for that year arising from the application of the efficiency benefit sharing scheme, the service target performance incentive scheme and the demand management incentive scheme–see paragraph (b)(5);

Clause 6.4.3(a)(6) also includes:

> …the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period—see paragraph (b)(6).

One of the building blocks is the carryover amounts incurred as part of the EBSS, which is defined in chapter 10 of the NER to be a scheme developed and published by the AER under clause 6.5.8. The current EBSS was published in accordance with the requirement of clause 6.5.8 of the NER in June 2008. The EBSS final decision states:

> The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first

[1] ESCV, *EDPR 2006–10, Vol.1, Chapter 10 Efficiency carryover mechanism,* October 2006, p. 415.

> revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.[2]

The prevailing jurisdictional arrangements that apply to the Victorian DNSPs are detailed in the ESCV's ECM which determines the efficiency carryover amounts for that will apply the forthcoming regulatory control period.

The AER will calculate and apply the carryovers in its determinations for the Victorian DNSPs in accordance with the requirements of the NER, the EBSS and the ESCV's ECM as set out in its *Electricity Distribution Price Review 2006–10* (2006 EDPR).[3]

13.2 AER draft decision

In assessing the Victorian DNSPs' proposed carryover amounts from the 2006–10 regulatory control period, the AER considered the following issues:

- application of efficiency carryover amounts to United Energy
- treatment of accrued negative carryover amounts arising from 2001–05 regulatory control period for Powercor
- ex post adjustments to the benchmark allowance associated with network growth
- consistency in the measurement of actual expenditure with the ESCV benchmark allowance
- treatment of uncontrollable and non-recurrent costs.

The AER’s draft decision on these issues is discussed in turn below.

In accordance with the requirements of clauses 6.4.3(a)(5) and 6.12.1(9) of the NER, the AER's EBSS and the ESCV's ECM (as set out in its *Electricity Distribution Price Review 2006–10* (2006 EDPR)), the AER calculated and applied the carryover amounts in its determinations for the Victorian DNSPs as set out in table 13.1.

2 AER, *Final decision, Electricity DNSPs’ EBSS,* June 2008, p. 13; AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, JEN, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, pp. 105–112.

3 Clause 6.12.1(9) of the NER, the AER’s EBSS June 2008, and ESCV's *Electricity Distribution Price Review 2006–10, Final decision, Volume 1,* October 2006.

Table 13.1 AER draft decision on the Victorian DNSPs' carryover amounts 2011–15 ($’m, 2010)

	2011	2012	2013	2014	Total
CitiPower	5.5	–6.9	–4.5	–4.7	**–10.6**
Powercor	–	15.6	0.3	–6.2	**9.7**
JEN	20.4	14.5	17.3	2.5	**54.8**
SP AusNet	–3.6	–23.3	–9.2	3.3	**–32.9**

Source: AER, Draft decision, Victorian electricity distribution network service providers Distribution determination 2011–2015, June 2010, p. 598.

13.2.1 Application of efficiency carryover amounts to United Energy

In its draft decision, the AER noted that United Energy has experienced ‘efficiencies’ over the current regulatory control period. In forecasting its opex requirements for 2011–15, the AER relied on the actual costs of United Energy’s related party service provider, Jemena Asset Management (JAM). These costs included losses incurred by JAM in providing these services to United Energy. Therefore, the AER noted that customers will not share in any efficiency gains arising from lower cost of JAM provided services. This reflected that the efficiency gains received by United Energy within the 2006–10 regulatory period were unsustainable. On this basis, the AER's draft decision did not determine United Energy's carryover amounts inclusive of related party margins.

Where the carryover amount is determined excluding related party margins, United Energy's carryover amount would be negative $50 million. This negative carryover amount was based on the actual costs of United Energy’s related party service provider, which incurred a loss in providing services to United Energy over the 2006–10 regulatory period. However, the AER in the draft decision considered this outcome to be anomalous, on the basis that United Energy would receive efficiency gains within the current regulatory period but register efficiency losses in its carryover amounts included in the forthcoming regulatory control period. The AER noted that where a negative carryover arises, the ESCV in its 2006 EDPR indicated that in considering whether to apply a negative carryover, the circumstances that gave rise to a negative carryover could be considered.

The AER determined a negative carryover amount for United Energy and decided not to apply the negative carryover amounts associated with efficiencies arising from the current regulatory period to United Energy.[4]

13.2.2 Treatment of accrued negative carryover amounts arising from 2001–05 regulatory control period

Powercor incurred a negative carryover amount of $22.9 million ($2004) during the 2001–05 period. Powercor argued, for several reasons, that this negative amount

[4] ESCV, *EDPR 2006–10, Vol.1, Chapter 10 Efficiency carryover mechanism*, October 2006, p. 435.

should not be applied.[5] The AER's draft decision considerations on these arguments are repeated briefly below.

The AER noted that in determining the revenue requirement for Powercor using a building block approach, the AER was required to include revenue increments or decrements from the application of the EBSS. The AER followed the approach set out in its EBSS decision and taking account of NER requirements in calculating and applying carryover amounts in accordance with the prevailing jurisdictional arrangements in place, namely the ESCV's ECM.[6]

Further, the AER considered that the NEVA also gave it authority to apply ESCV's ECM set out in Chapter 10 of the EDPR to Powercor's revenue requirements for the 2011–15 regulatory control period.[7]

Notwithstanding the arguments of Powercor, the AER did not consider it appropriate to reconsider the calculation of the ESCV nor to set aside the accrued negative carryover amount. The AER's reasons were:

- the appropriate time to consider these issues would have been at the time of the 2006 EDPR, noting that Powercor and the other DNSPs did not raise these issues as part of the ESCV's 2006 EDPR

- any revisiting of the accrued negative calculation or the setting aside of the accrued negative carryover amount also requires that all the efficiency amounts (derived in the same regulatory period as the accrued negative amount) received by the DNSP be revisited, however, the AER does not have any discretion to revisit any positive carryover amounts , or more specifically to completely recalculate all the efficiency carryover amounts from prior regulatory control periods

- the ORG and ESCV were required to have regard to a fair sharing of efficiency benefits in establishing their ECM.[8]

- The AER rejected claims by Powercor that the AER did not have power to apply this negative carryover amount.

13.2.3 Ex post adjustments to the benchmark allowance associated with network growth

The AER in its draft decision adopted the same growth adjustment formula specified by the ESCV in its 2006 EDPR to calculate the carryover amounts for the 2011–15 regulatory control period. [9]

The AER noted the ESCV's comments on growth adjustments, which stated:

> In considering this growth adjustment coefficient for use in the calculation of future efficiency carryover amounts, the Commission is cognisant of the

5 AER, *Vic Draft Decision*, June 2010, pp. 562–80
6 ibid., p. 557.
7 ibid., p. 571.
8 ibid., pp. 575–78.
9 ibid., pp. 580–81.

> fact that the future necessarily involves uncertainty and that it is neither prudent nor possible to make permanent now the future application of this aspect of the efficiency carryover mechanism. This coefficient therefore represents a guide to inform future debate and decisions on this issue and give greater certainty as to the merit assessment made during this review.[10]

The AER considered that it would have been reasonable for the Victorian DNSPs to anticipate the application of this approach to carryover amounts. Accordingly, the AER's draft decision applied the growth adjustment formula specified by the ESCV. This was used to calculate the carryover amounts for the 2011–15 regulatory control period.

The AER considered that the growth adjustment proposed by the Victorian DNSPs was inconsistent with the ESCV's growth adjustments. The AER considered that the Victorian DNSPs applied an incorrect growth averaging formula. The AER in its draft decision indicated that it would update the growth adjustment calculation based on actual customer numbers, energy and peak demand for 2009 in its final determination to determine the carryover amounts for the Victorian DNSPs. [11]

13.2.4 Consistency in the measurement of actual expenditure with the ESCV benchmark allowance

The AER's draft decision noted a number of adjustments (from the 2006 EDPR) that it considered to be necessary to ensure a ‘like for like’ comparison between the benchmark allowance and actual expenditure in calculating the efficiency carryover amounts for 2006–10. These adjustments were related to:

- growth adjustments
- capitalisation of overheads
- movements in non cash costs (that is, provisions).[12]

The AER was committed to reviewing the Victorian DNSPs’ regulatory accounts for 2009 in as part of this final decision. This was to have regard to any changes to capitalisation of indirect overheads. The draft decision also required JEN to substantiate its proposed adjustment of $4.34 million in 2008 and 2009 as a result of the change in its capitalisation policy. The AER's draft decision also adjusted the original ESCV benchmark allowances for changes in capitalised indirect overheads for SP AusNet to ensure that the actual expenditure and the ESCV benchmark allowances are considered on a ‘like for like’ basis in measuring the carryover amounts for the 2006–10 regulatory period.

The AER accepted CitiPower and Powercor's capitalisation policy has not changed over for the period 2006–08.

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[10] ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 436.

[11] AER, *Vic Draft Decision*, June 2010, p. 582.

[12] ibid., pp. 167–68. The AER notes that the ESCV in its 2006 EDPR also reallocated costs between services during the regulatory control period.

In relation to adjustments for movements in provisions (non cash items) that distort reported expenditure, only CitiPower and Powercor proposed to remove the impact of provisions.

The AER reviewed these proposed provisions and made adjustments for some minor differences between the movement in provisions reported in Powercor's regulatory accounts and its regulatory proposal. The AER's draft decision also adjusted SP AusNet's movement in provisions for an assumed allocation of costs between its gas and electricity businesses. The AER's draft decision also required SP AusNet to provide further information to enable movements in provisions for the assumed allocation between its gas and electricity businesses to be verified. The AER has also adjusted JEN's expenditure for miscellaneous provisions to ensure a 'like for like' comparison of actual expenditure and the ESCV benchmark allowance for 2006–10.

The AER also made the following adjustments in its draft decision:

- Related party margins - in calculating the Victorian DNSPs' efficiency carryover amounts, the AER excluded the amount of actual related party margins
- Licence fee - The AER committed to reviewing the actual licence fee for 2009 in this final decision, and where necessary adjusting the carryover amounts to reflect the actual licence fee paid.
- AMI reclassification (CitiPower and Powercor) - The AER did not accept further amendments to their regulatory accounts for 2006–08. Accordingly, the AER adjusted CitiPower and Powercor's carryover amounts where the allocation of costs in its regulatory proposal related to AMI was inconsistent with their re-audited regulatory accounts.
- Non-network activities - the AER did not exclude these costs from JEN, given that these costs were included in the ESCV benchmark allowances for 2006–10.

13.2.5 Treatment of uncontrollable and non-recurrent costs

The AER did not adjust the ESCV benchmark allowances for uncontrollable costs on the basis that:

- the ESCV did not explicitly allow for these adjustments in its ECM to apply to the Victorian DNSPs for the 2011–15 regulatory control period
- the Victorian DNSPs did not raise the issue of uncontrollable costs in the ECM in the 2006 EDPR and have previously criticised any attempts to distinguish between management induced efficiencies (controllable costs) and windfall gains (uncontrollable costs)
- any adjustment for windfall losses would require a consideration of windfall gains (however, given the information asymmetry, the DNSPs may not identify windfall gains)

The AER decided to override the presumption in the ECM to apply negative a carryover amounts [13] where this negative carryover amount arises due to the occurrence of a non-recurrent cost in the base year, on the basis that the inclusion of non-recurrent costs in determining the carryover amounts may reduce the Victorian DNSPs' incentives to reveal their efficient costs over the forthcoming regulatory control period, contrary to clause 6.5.8(c) of the NER.

13.3 Victorian DNSP revised regulatory proposals

The efficiency carryover amounts arising from the 2006–10 regulatory control period, proposed by the Victorian DNSPs' to be included in the building block revenue requirements for each DNSP, are summarised in table 13.2.

Table 13.2 Victorian DNSPs' revised efficiency carryover amounts 2011–15 ($'m, 2010)

	2011	2012	2013	2014	Total
CitiPower	–	–	–	–	**–**
Powercor	25.9	22.5	1.9	–6.6	**43.7**
JEN	16.8	11.7	13.6	–1.4	**40.7**
SP AusNet	14.6	–23.1	–4.3	3.7	**–9.0**
United Energy	–	–	–	–	**–**

Source: CitiPower, *Revised regulatory proposal*, table 14.3, p. 389; Powercor, *Revised regulatory proposal*, table 14.3, p. 387; JEN, *Revised regulatory proposal*, table 13.3, p. 274; SP AusNet, *Revised regulatory proposal*, table 9.3, p. 290. United Energy, *Revised regulatory proposal*, table 11.4, p. 229.

13.3.2 CitiPower

CitiPower stated that it does not agree with the AER's decision to reject CitiPower's proposed adjustments to the 2006–10 carryover amounts to exclude superannuation costs and GSL payments, on the basis that these costs are uncontrollable.[14] CitiPower rejected the AER's decision to remove the ESCV's 0.39 per cent partial productivity factor adjustment.[15] CitiPower also rejected the amount of the AER's adjustments regarding provisions, licence fees and network growth in calculating the 2006–10 carryover amounts.[16]

CitiPower also did not agree with the AER's decision to reject CitiPower's proposed net present value (NPV) approach for determining the 2006–10 carryover amounts. Under this approach, CitiPower's carryover amount would be set to zero instead of a negative amount. CitiPower considered the AER's decision not to set its carryover

13 ibid., p. 435.
14 CitiPower, *Revised regulatory proposal*, July 2010, p. 371.
15 ibid., p. 371.
16 ibid.

amounts to zero to be inconsistent with the ESCV's reasoning in its 2006 EDPR where an NPV approach was adopted for reasons consistent with the AER's decision.[17]

CitiPower argued that the AER's decisions in relation to the NPV approach are incorrect, based in part on errors of law and errors of fact, and are inconsistent with the NEO, the revenue and pricing principles and the objectives of the ECM and the EBSS.[18]

13.3.3 Powercor

Powercor submitted that it did not accept the AER's decision to deduct its accrued negative carryover arising from the 2001–05 regulatory period from Powercor's 2006–10 efficiency carryover amounts. Powercor submitted that the AER has no power under the NER to take the 2001–05 negative carryover amounts into account in making its final determination.[19]

Powercor also did not agree with the AER's draft decision that the AER is authorised and required by the AER's EBSS, the ESCV's 2006 EDPR and the NEVA to deduct this negative carryover. Powercor submitted that the draft decision was based on several errors of law.[20]

Powercor amended its initial regulatory proposal to incorporate the AER's adjustments to the 2006–10 carryover amounts in relation to:

- related party margins and
- advanced metering infrastructure (AMI) reclassification.[21]

However, other than the adjustments, identified above, Powercor did not accept the AER's other positions in the draft determination.[22] In particular, Powercor stated that it does not accept the AER's decision to reject Powercor's proposed adjustments to the 2006–10 carryover amounts to:

- exclude uncontrollable costs
- remove the ESCV's $5.5m ($2004) efficiency adjustment to the benchmark allowance and
- remove the ESCV's 0.39 per cent partial productivity adjustment to the benchmark allowance.[23]

Powercor also stated that it does not agree with the amount of the adjustments the AER made in relation to provisions, licence fees or network growth in calculating the carryover amounts.[24]

[17] ibid., p. 371.
[18] ibid., p. 371.
[19] Powercor, *Powercor Australia Ltd's Revised regulatory proposal 2011–15*, July 2010, p. 362.
[20] Powercor, *Revised regulatory proposal*, July 2010, p. 362.
[21] ibid., p. 384.
[22] ibid., p. 387.
[23] ibid., p. 362.

Powercor updated its proposed adjustment amounts to calculate the carryover amounts for increased vegetation management costs based on the most recent available information for 2008 and 2009.[25]

13.3.4 JEN

JEN noted in its revised proposal that it used actual 2009 opex and the AER's draft decision method to calculate a revised efficiency carryover amounts to add to its 2011–15 building block revenue requirements. These revised amounts totalled $40.7 million.[26]

JEN also provided the AER with additional information supporting the impact of the change in its capitalisation policy. This related to the implementation of a new cost allocation method which affected the allocation of corporate costs and the capitalisation of these costs for 2008 and 2009. JEN's revised proposal has reflected this capitalisation policy change in calculating its efficiency carryover amounts.[27]

13.3.5 SP AusNet

SP AusNet rejected the use of the growth adjustment formula, on the basis that this:

- leads to both intuitive and theoretically incorrect outcomes
- does not reflect the modelling approach adopted by the ESCV to derive the opex benchmarks included in the 2006 EDPR
- does not reflect the actual impact of growth on SP AusNet’s costs within the regulatory period.[28]

SP AusNet also submitted that it did not accept the AER's indirect corporate overheads adjustment in relation to the calculation of the efficiency carryover amounts for the 2006–10 regulatory period, on the basis that:

- the underlying definition of ‘indirect (corporate) overheads’ used by the AER in assessing this issue is materially different to the definition that underpinned the statement attributed to the ESCV in their final decision
- there has been no change in SP AusNet’s capitalisation policy since 2001
- the AER’s RIN did not seek to capture information that would in fact allow it to make a ‘like for like’ comparison for the purposes of calculating carryover amounts for the 2006–10 regulatory period, therefore, SP AusNet has not previously had the opportunity to provide any relevant information on this material issue.[29]

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24 ibid., p. 362.
25 ibid., p. 387.
26 JEN, *Revised regulatory proposal*, July 2010, p. 271
27 ibid., p. 274
28 SP AusNet, *Revised regulatory Proposal*: *Electricity Distribution Price Review 2011–2015*, July 2010, p. 290.
29 SP AusNet, *Revised regulatory proposal*, July 2010, p. 278.

13.3.6 United Energy

United Energy agreed with the AER's decision to apply its discretion to not apply any negative carryover amount associated with efficiencies arising from the current regulatory period to United Energy and for the purposes of this revised proposal United Energy proposed a carryover amount of zero.[30]

13.4 Submissions

No submissions were received on this matter.

13.5 Issues and AER considerations

In assessing the Victorian DNSPs' proposed carryover amounts from the current regulatory period, the AER has considered the following issues:

- application of efficiency carryover amounts to United Energy
- treatment of Powercor's accrued $22.9 million ($2004) negative carryover amount arising from the 2001–05 regulatory period
- proposed NPV approach for determining 2006–10 carryover amounts for CitiPower
- ex post adjustments to the benchmark allowance associated with network growth
- AER adjustments to the ESCV benchmark allowance and actual opex
- treatment of uncontrollable and non-recurrent costs

These issues are considered below.

13.5.1 Application of efficiency carryover amounts to United Energy

13.5.1.1 AER draft decision

The AER considered that United Energy's carryover amounts should be determined exclusive of margins, to ensure that the ESCV's benchmark allowance and actual expenditure are compared on a like for like basis.[31] The AER calculated United Energy's carryover amount to be negative $50 million on the basis that actual and benchmark expenditure are compared exclusive of related party margins. This negative carryover amount was based on the actual costs of United Energy's related party service provider, which incurred a loss in providing services to United Energy over the 2006–10 regulatory period. However, the AER in the draft decision considered this outcome to be anomalous, on the basis that United Energy would receive efficiency gains within the current regulatory period but register efficiency losses in its carryover amounts. The AER also noted the ESCV stated that while a negative carryover will be presumed to apply, this presumption will be based on the circumstances that have given rise to that negative carryover amount. Consequently,

30 United Energy, *Revised regulatory proposal for Distribution Prices and Services January 2011–December 2015*, July 2010, p. 225.
31 AER, *Vic Draft Decision*, June 2010, p. 561.

the AER decided to use its discretion to not apply the negative carryover amounts associated with efficiencies arising from the current regulatory period to United Energy. [32]

13.5.1.2 Victorian DNSP revised regulatory proposals

United Energy agreed with the AER's decision to apply its discretion to not apply any negative carryover amount associated with efficiencies arising from the current regulatory period. For the purposes of its revised proposal United Energy proposed a carryover amount of zero.[33]

13.5.1.3 Issues and AER considerations

The AER considers its decision needs to be distinguished from United Energy's revised regulatory proposal, which sough a zero amount. For the draft decision, the AER has not applied the ECM to United Energy rather than set a zero carryover amount. The AER maintains its decision to not apply the ECM associated with efficiencies arising from the current regulatory period to United Energy. In particular, the AER has set aside the application of the ECM to United Energy on the basis that this would be consistent with the NEO and 7A(3) of the NEL.

13.5.1.4 AER conclusion

In making this decision, the AER has had regard to the NEO and the revenue and pricing principles. In particular, the AER considers the non-application of the ECM to United Energy is in the long term interests of customers given that customers would not share in any 'efficiency benefits' received by United Energy in the 2006–10 regulatory period given United Energy's costs were unsustainable.[34] Alternatively where United Energy's carryover amounts are calculated exclusive of related party margins, this may not promote effective incentives for United Energy to pursue efficiencies given that it will receive unsustainable efficiency gains within the current regulatory period and unsustainable efficiency losses in 2011–15 regulatory control period.

The AER is using its discretion to not apply carryover amounts, has taken into account into the revenue and pricing principles of the NEL. The AER considers that this decision is consistent with promoting effective incentives in order to promote economic efficiency and the efficient provision of services consistent with the 7A(3) of the NEL and the NEO, given that not applying the negative carryover amounts will remove any detrimental impact on United Energy's incentive to pursue economic efficiencies.

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32 ibid. p. 561.

33 United Energy, *Revised Regulatory Proposal for Distribution Prices and Services January 2011–December 2015*, July 2010, p. 225.

34 This will be the case where United Energy's efficiency carryover amounts are calculated inclusive of related party margins. That is a carryover amount inclusive of margins reflects the loss JAM has incurred during the current regulatory period in servicing United Energy' network.

13.5.2 Treatment of Powercor's accrued negative carryover amounts arising from 2001–05 regulatory control period

13.5.2.1 AER draft decision

Powercor accrued a negative carryover amount of $22.9 million ($2004) under the ORG's ECM scheme in the 2001–05 regulatory control period. The ESCV did not apply this negative carryover amount as part of the ECM at the time of its 2006 EDPR.[35] In effect, this amount was not subtracted from Powercor's revenue requirement for the 2006–10 regulatory control period, given that the ESCV decided that no net negative carryover amounts would be applied when incorporating the efficiency carryover amount into the revenue requirement for the 2006–10 regulatory period (referred to as the NPV with a 'zero floor'[36]) on the basis that:

> The ORG (2000a, p. 117) stated that efficiency gains and losses would be treated symmetrically in calculating efficiency carryover amounts from the 2001-05 period as this was considered essential to preserving the incentive properties of the mechanism. However, it also accepted that, where negative carryovers were accrued and applied in the 2006-10 period, this might result in distributors receiving less than the building blocks revenue requirement that an efficiently operating distributor would require in that regulatory period.
>
> As a result, the ORG foreshadowed that no negative carryover would be applied when incorporating the efficiency carryover amount into the revenue requirement for the 2006-10 regulatory period (referred to as the 'zero floor').[37]

In other words, where in aggregate over the regulatory period a DNSP's efficiency losses outweighed efficiency gains (in NPV terms), the Victorian DNSP's carryover amounts for 2006–10 would be set to zero, with the accrued negative carryover amounts to be possibly offset against any future positive carryover amounts in the next regulatory period. The AER considered the following issues raised by Powercor and its advisors, NERA Consulting (NERA) in relation to the treatment of Powercor's accrued negative carryover amount arising from the 2001–05 regulatory control period:

- AER's authority to apply the EBSS and negative carryover amounts accrued in 2001–05 under the ECM
- prior expectations regarding the treatment of accrued negative carryover amounts
- consistency with NER and NEO and the NEL where the accrued negative carryover amount is applied to Powercor's building block revenue requirement

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35 ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 417–18.

36 The ESCV's adopted an NPV approach with a 'zero floor' in the 2006 EDPR. Under this approach, a negative carryover amount was not applied to the revenue requirement for the 2006–10 regulatory period, where the sum of the 2001–05 regulatory period was negative in NPV terms. Instead where the sum of the accrued negative carryover amounts for the 2001–05 regulatory period was negative in NPV terms, the efficiency carryover amount was set to zero for each year of the 2006–10 regulatory period. Conversely, where the sum of the accrued efficiency carryover amounts for the 2001–05 regulatory period was positive in NPV terms, the efficiency carryover amount was incorporated in the revenue requirement for the 2006–10 regulatory period.

37 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 424.

- effect on incentives of carrying forward the accrued negative carryover.

The AER decided to apply the negative carryover amount of $27.2 million ($2010) by deducting this amount from the positive amounts arising from the 2006–10 regulatory control period to determine Powercor's revenue requirements for the 2011–15 regulatory control period.

13.5.2.2 Victorian DNSP revised regulatory proposals

Powercor stated in its revised proposal that the AER's conclusion in its draft determination is incorrect and based on errors of law. Powercor considers that the AER has no power under the NER to address the 2001–05 accrued negative carryover in its final determination and that to do so would be contrary to the NEO and revenue and pricing principles.[38] Powercor submitted that the ESCV's 2006 EDPR and the AER's own final decision cannot confer any powers on the AER that are not provided under the NER.[39]

Powercor disagreed with the AER's draft determination which stated that the NEVA authorises the AER to deduct the 2001–05 negative carryover as part of enforcing the 2006 EDPR. Powercor provided the following reasons as to why it considered this to be an error of law:

> - The AER's powers under the NEVA in relation to the ESCV's 2006-10 EDPR only apply during the term of the ESCV's 2006-10 EDPR, ie 1 January 2006 to 31 December 2010. From 1 January 2011, the AER's powers in relation to the economic regulation of DNSPs are set out in the NEL and the Rules. The NEVA does not confer on the AER a power to effectively carry over parts of the ESCV's 2006 EDPR into 2011-15 and to disregard the limitations on its powers under the NEL and Rules.[40]

Powercor also disagreed with the AER's statement that section 25 of the NEVA authorises it to enforce the ESCV's 2006 EDPR and that carrying over the 2001–05 negative carryover is part of the exercise of that power. Powercor provided the following reasons as to why this was an error of law:

> - section 25 only applies *'if a relevant DNSP has contravened or is contravening, or in the opinion of the AER, likely to contravene'* the ESCV's 2006-10 EDPR or certain conditions of the distribution licence;
>
> - Powercor Australia has not contravened the ESCV's 2006-10 EDPR or its distribution licence, so section 25 does not apply and is simply not relevant to this issue;
>
> - in any event, the only enforcement action authorised under section 25 is to serve a provisional order or final order requiring compliance with the 2006 EDPR, and the NEVA does not authorise the AER to include a matter in its Final Determination as part of its enforcement powers.[41]

[38] Powercor, *Revised regulatory proposal 2011–15,* July 2010, p. 364.
[39] ibid., p. 364.
[40] ibid., p. 365.
[41] ibid.

Powercor also considered that the ESCV's 2006 EDPR does not set out a clear position on the treatment of the 2001–05 negative carryover amount after 2010 and does not require that it must be deducted in 2011–15. Powercor submitted that the 2006 EDPR only states the ESCV's expectation that the 2001–05 negative carryover amount could 'possibly' be deducted from any future positive carryover amount.[42]

In relation to the NER, Powercor also considered that the AER has no power to take the 2001–05 negative carryover into account for its 2011–15 determination because:

- The AER's only power under the NEL or NER in relation to carryover over efficiency gains or losses from prior regulatory control periods is to apply a building block revenue increment or decrement under NER clause 6.4.3(a)(6).
- NER clause 6.4.3(a)(6) only empowers the AER to apply revenue increments or decrements arising from the application of a control mechanism in the previous regulatory control period.
- The carrying over of the 2001–05 negative carryover is not a revenue increment or decrement arising from the application of a control mechanism in the previous regulatory control period.[43]

Powercor considered that the AER's reasoning in relation to the 2001–05 accrued negative carryover amount is inconsistent with its reasoning and conclusions applied to JEN's proposal. Specifically, JEN has proposed that it be compensated for financing costs associated with the over-spend of its capex allowance for 2006–10.[44] Powercor noted that the AER acknowledged the ESCV's provision for Victorian DNSPs to be able to recover financing costs due to capex overspend, by rolling any overspend into the its RAB in 2011. Powercor noted that the AER determined it was unable to give effect to this expectation as the relevant NER provisions do not allow it to make such adjustments to the opening RAB.[45]

Powercor also did not agree with the AER's view that Powercor is seeking to apply the requirements of the NEL and NER retrospectively to the ESCV's ECM. Powercor stated that the decision the AER is required to make is a decision under clause 6.4.3(a)(6) in relation to the amount of revenue increments or decrements that arise from the carryover of gains or losses into the 2011–15 regulatory control period.

Submissions on DNSP regulatory proposals

No submissions were received on this matter.

[42] ibid.
[43] ibid.
[44] ibid., p. 366.
[45] ibid.

13.5.2.3 Issues and AER considerations

AER requirement to apply the ECM under the NER

The AER does not agree with Powercor's view that the AER does not have the power under the NER to apply the 2001–05 accrued negative carryover amount of $27.2m ($, 2010).[46]

The AER maintains its position as discussed in the draft decision,[47] that the AER is required to apply the ECM as set out in the 2006 EDPR to determine the revenue increments or decrements to the DNSPs' building block revenue in accordance with clause 6.4.3(a)(6) of the NER . This is because the AER is responsible for approving Powercor's annual revenue requirement for each year of the 2011–15 regulatory control period. This is to be done using a building block approach, which includes the carryover amounts incurred as part of the EBSS under clause 6.4.3(a)(5) which states:

> the revenue increments or decrements (if any) for that year arising from the application of the *efficiency benefit sharing scheme*, the *service target performance incentive scheme* and the *demand management incentive scheme* - see paragraph (b)(5);[48]

The AER notes that as stated above, further details of clause 6.4.3(a)(5) are provided in clause 6.4.3(b)(5) which states:

> the revenue increments or decrements referred to in paragraph (a)(5) are those that arise as a result of the operation of an applicable efficiency benefit sharing scheme as referred to in clauses 6.5.8.[49]

The AER published the current EBSS that is to apply to the Victorian DNSPs in accordance with the requirements of clause 6.5.8 of the NER in June 2008. The EBSS final decision included the statement:

> The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.[50]

Accordingly, the EBSS made under clause 6.5.8 of the NER requires the AER to calculate the carryover amounts for the 2011–15 regulatory control period in accordance with the existing ECM scheme.[51] Specifically, as this is the first electricity distribution determination for Victorian DNSPs since the transition to the national regime, the AER must apply the ECM as set out in the 2006 EDPR in accordance with section 2.3.4 of the EBSS,[52] and the AER's EBSS final decision.

Further to this, the AER also notes that in response to the AER's EBSS draft decision, Powercor, along with CitiPower and ETSA Utilities sought clarification from the

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46 ibid., p. 364.
47 AER, *Vic Draft Decision*, June 2010, pp. 569–80
48 Clause 6.4.3(a)(5) of the National Electricity Rules.
49 Clause 6.4.3(b)(5) of the National Electricity Rules.
50 AER, *Electricity DNSPs EBSS*, June 2008, p. 13.
51 NER s.6.5.8–Efficiency benefit sharing scheme.
52 AER, *Electricity distribution network service providers–Efficiency benefit sharing scheme*, June 2008, p. 7.

AER that it would use jurisdictional arrangements to calculate carryovers for DNSPs currently operating under jurisdictional efficiency carryover schemes.[53] The AER also notes that Powercor, along with CitiPower and ETSA Utilities did not raise any objections with the AER applying existing jurisdictional efficiency carryover schemes, in this case the ECM, at the time of making its EBSS final decision.

As noted above, the AER is required to determine Powercor's revenue requirement for each year of the 2011–15 regulatory control period, using a building block approach. One of these building blocks is the revenue increments (decrements) from the application of the EBSS. The AER made its EBSS under clause 6.5.8 of the NER.

The AER also notes that the ESCV's 2006 EDPR stated:

> Powercor has an accrued negative carryover amount of $22.9 million to possibly be off-set against positive carryover amounts at the end of the 2006–10 regulatory period.[54]

As the accrued negative carryover amount of $22.9m ($2004) is set out in the 2006 EDPR, the AER is required to consider whether to apply the accrued negative carryover amount in calculating the increment or decrement to Powercor's building block revenue requirement in the 2011–15 regulatory control period. It follows that in the event that this accrued negative carryover amount is applied by the AER this must be applied in accordance with clause 6.4.3(a)(6) of the NER and the AER's EBSS.

In conclusion, the AER is making its 2011–15 revenue determination for Powercor under the regulatory framework of the NEL and the NER. In accordance with the EBSS final decision made under 6.5.8 of the NER, the AER is required to apply the EBSS to the Victorian DNSPs for the forthcoming regulatory control period. The EBSS allows the AER to calculate and apply carryover amounts for the forthcoming regulatory control period from, and in accordance with, existing jurisdictional schemes, in this case the ESCV's ECM.[55] Accordingly, the AER's authority to apply ESCV's ECM comes from the NER which has given effect through the AER's EBSS, which is being applied in this decision.

AER authority to apply negative carryover amounts accrued in 2001–05

The AER accepts Powercor's view that the AER's powers under the NEVA in relation to the ESCV's 2006–10 EDPR only apply during the term of the 2006 EDPR (1 January 2006 to 31 December 2010). The AER also on further review accepts that it cannot rely on the NEVA to apply the 2006 EDPR to the 2011–15 regulatory control period and that application of relevant aspects of the 2006–10 EDPR must be in accordance with the NEL and the NER. That said as set above, the AER considers that it does have authority to calculate and apply carryover amounts in accordance with efficiency carryover schemes that are currently operating in relevant jurisdictions. Section 2.3.4 of the EBSS states that: *'the AER will apply all carryovers, both positive and negative'*.[56]

Similarly, the AER's EBSS Final Decision (June 2008) states:

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53 AER, *Electricity DNSPs EBSS*, June 2008, p. 12.
54 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 418.
55 AER, *Electricity DNSPs EBSS*, June 2008, p. 13.
56 ibid., p. 7.

> The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.[57]

The EBSS and EBSS Final Decision (June 2008) were developed by the AER under clause 6.5.8 of the NER. The consultation requirements in making the EBSS decision were adhered to by the AER. Further, Powercor sought clarification that the AER would use these jurisdictional arrangements to calculate carryovers for its first revenue determination during this process.[58] Accordingly, the AER considers it is able to calculate and apply both positive and negative carryover amounts in accordance with its EBSS.

The AER also notes that the ESCV's 2006–10 EDPR states:

> Powercor has an accrued negative carryover amount of $22.9 million [from the 2001-05 period] to possibly be offset against positive carryover amounts at the end of the 2006-10 regulatory period [59]

On the basis of this statement, the AER considers that it has discretion to offset the negative carryover amount accrued by Powercor in the 2001–05 regulatory period against any positive carryover amounts arising in the 2006–10 regulatory period. The AER notes that this statement uses the term 'possibly' and considers that this term gives the AER discretion to offset the negative carryover amount accrued by Powercor in the 2001–05 period against positive carryover amounts accrued in the 2006–10 period.

AER discretion to offset Powercor's negative carryover amount from 2001–05

The AER considers that in applying Powercor's accrued negative carryover amounts for 2001–05 regulatory period, it is using its discretion in a manner consistent with the NEO, the revenue and pricing principles under the NEL and clause 6.5.8(c) of the NER.

Section 7A(3) requires the regulator to provide DNSPs with effective incentives in order to promote economic efficiency with respect to direct control network services. In applying the negative carryover amount, the AER does not consider that this will be inconsistent with the promotion of economic efficiency. This is because the negative carryover amount will be fully offset against positive carryover amounts accrued in the 2006–10 regulatory period. This will not affect Powercor's incentives to seek future efficiencies. In addition, the AER considers that all negative and positive carryover amounts are taken into account in order to provide Victorian DNSPs with effective incentives to promote efficiency consistent with 7A(3) of the NEL.

Further, the AER notes that the principle in section 7A(2) of the NEL requires the DNSPs to be provided with a reasonable opportunity to recover efficient costs. As demonstrated above, because the negative carryover amount is only being offset against positive carryover amounts in the 2006–10 regulatory period in accordance

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57 AER, *EBSS final decision*, June 2008, p. 13.

58 CitiPower and Powercor, *Proposed electricity distribution network service provider guidelines*, May 2008, p. 4 (in AER, EBSS *Final decision*, June 2008, p. 12.).

59 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 418.

with the ESCV's 2006 EDPR, Powercor will not be denied a reasonable opportunity to recover its efficient costs.[60]

That said the AER does not consider that negative carryover amounts to be inconsistent with the NEL and the NER because the efficiency carryover incentive mechanism applies only to the operating and maintenance expenditure component of the building block revenue allowance. This means that while DNSPs may incur a negative revenue assessment on this revenue component, they will still be receiving revenues from all other components of the building blocks. The AER's more detailed reasoning is contained in section 13.5.3.3.

Moreover, the AER rejects Powercor's argument that applying accrued negative carryover amount is inconsistent with clause 6.5.8(c) of the NER. As set out above, the AER considers that applying the negative carryover amount which is fully offset against positive carryover amounts in the current regulatory period, will not affect Powercor's continuous incentive to reduce opex, in accordance with clause 6.5.8(c)(2) of the NER.[61] Indeed, the desirability of both rewarding Victorian DNSPs for efficiency gains and penalising DNSPs for efficiency losses requires the accrued negative carryover amount to be offset against positive carryover amounts, in accordance with clause 6.5.8(c)(3) of the NER.

The AER confirms that it adhered to the consultation procedures in developing and publishing the EBSS, and had regard for each of the above requirements under clause 6.5.8(c) of the NER.[62] As noted above, the EBSS final decision and the NER also required the AER to apply existing jurisdictional incentive schemes when implementing the EBSS, such as the ECM. The AER accepted submissions from Powercor, along with CitiPower and ETSA Utilities, seeking clarification from the AER that the AER would use jurisdictional arrangements to calculate carryovers for the DNSPs currently operating under jurisdictional efficiency carryover schemes, and had regard to those submissions in making its decision.[63]

Further, the AER rejects Powercor's argument that applying accrued negative carryover amount is inconsistent with the NEO. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity. As set out above, the AER has applied the accrued negative carryover amount such that this amount is fully offset against positive carryover amounts in the 2006–10 regulatory period. This will not affect Powercor's incentives to seek future economic efficiencies, which is consistent with the NEO.

The AER also considers it is necessary to adopt a symmetrical treatment of gains and losses to ensure that Victorian DNSPs are provided with an incentive to make operational savings in each year of a regulatory period. In particular, the EBSS applies

60 ibid., p. 424.
61 cl 6.5.8 (c) (2) of NER
62 AER, *EBSS Final decision*, June 2008, pp. 19–20
63 ibid., p.12.

a symmetrical approach, where both, efficiency gains or losses are applied or carried over for the forthcoming regulatory control period.[64]

The AER notes that the ECM specified in chapter 10 of the 2006 EDPR also specified a symmetrical approach to the treatment of efficiency gains and losses to be applied in the 2011–15 regulatory control period, where the carryover amount may include a positive or negative amount. The ESCV stated that:

> The Commission considers that …….the symmetric application of efficiency gains and losses, will result in the operating and maintenance expenditure efficiency carryover mechanism providing greater benefits to customers than the potential costs of paying for the associated efficiency carryover rewards. Therefore the Commission continues to consider that the efficiency carryover mechanism is effective in providing incentives for operating and maintenance expenditure and the sharing of those benefits with customers.[65]

The ESCV further stated that:

> In addition to the inability of the efficiency carryover mechanism to achieve its objectives if it is not symmetrically applied within the regulatory period, the incentive powers of the mechanism are strengthened where it is symmetrically applied across regulatory periods and ensures distributors are not rewarded for unsustainable efficiencies. [66]

The AER considers the ESCV's statement that the accrued negative carryover amount could be possibly offset against future positive amounts is also consistent with the symmetric treatment of efficiency gains or losses.

AEMC's views on operating expenditure incentives

The AER is cognisant of the views expressed by the Australian Energy Market Commission (AEMC) regarding the issue of negative carryover amounts and the requirements of the revenue and pricing principles.[67]

The AER notes that the AEMC stated:

> The efficiency benefit-sharing mechanism for operational expenditure aims to provide continuous incentive for TNSPs to make operating expenditure savings in each year of a regulatory period. The Commission considers that providing anything other than a rule framework which provides for the symmetric treatment of expenditure efficiency gains and losses would prevent the incentive mechanism from achieving its objective of providing even incentives in each year.[68]

The AER agrees with this view that it is necessary to adopt a symmetrical treatment of gains and losses to ensure that Victorian DNSPs are provided with an incentive to make operational savings in each year of a regulatory period.

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64 Under the AER's EBSS the DNSPs there is no banking of negative carryover amounts such that any negative carryover amount is applied even if there are no positive carryover amounts to offset any negative amounts.

65 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 431.

66 ibid., p. 434.

67 AEMC, *Rule Determination–National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18*, November 2006, pp. 96–97.

68 AEMC, *Rule Determination–National Electricity Amendment*, November 2006, p. 96.

The AER also observes that:

> The Commission is cognisant of the requirement of section 35(3)(a) of the NEL which requires that rules in relation to economic regulation of transmission systems to 'provide a reasonable opportunity for a regulated transmission system operator to recover the efficient costs of complying with a regulatory obligation.' However it does not consider that this requires the Revenue Rule to prescribe a 'no negative carry-over' approach to economic regulation.[69]

The AER notes that section 35(3)(a) as referred to by the AEMC is now clause (2)(b) of the revenue and pricing principles under section 7(A) of the NEL. This supports the view that applying Powercor's accrued negative carryover amount is not inconsistent with the revenue and pricing principles. Indeed this suggests that where the accrued negative carryover amount is not applied that this would be inconsistent with the revenue and pricing principles in the NEL.

The AER also notes that the AEMC stated:

> The Commission considers that where the AER were not permitted to take into consideration a negative efficiency carry-over in the determination of the MAR [Maximum Allowed Revenue] for the ensuing regulatory period, the intent and benefit of the incentives scheme would be prevented.[70]

Further, the AEMC also goes on to state:

> In addition, the Commission does not consider that applying a negative carry-over is inconsistent with the NEL requirements. Specifically, the efficiency carry-over incentive mechanism applies only to the operating and maintenance expenditure component of the building block revenue allowance. This means that while TNSPs may incur a negative revenue assessment on this revenue component, they will still be receiving revenues from all other components of the building blocks.[71]

Finally, the AEMC noted:

> Furthermore, in some instances, TNSP's will also be receiving increased revenue through improved performance, via the service incentive arrangements. Therefore, in combination with other elements of the building block and incentive mechanism framework the TNSPs will likely be able to adequately fund their prescribed service requirements.[72]

The AER concurs with the views of the AEMC, and notes that these views apply equally to both TNSPs and DNSPs. In conclusion, consistent with the AEMC's views, the AER considers that:

- applying the accrued negative carryover amount from 2001–05 in Powercor's building block revenue for the 2011–15 regulatory control period is not inconsistent with the objectives of the EBSS, the NEO or the revenue and pricing principles in section 7A of the NEL

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69 ibid.
70 ibid.
71 ibid.
72 ibid.

- were it not allowed to apply Powercor's negative efficiency carryover in determining Powercor's revenue requirement for 2011–15, the intent and benefit of the EBSS would be prevented, where the ESCV's ECM is the applicable EBSS for the 2011–15 regulatory control period

- as the ECM only applies to the opex component of the building block model, Powercor (and in this case the accrued negative carryover is only being offset against positive carryover amounts) Powercor will still be receiving revenues from all other components of the building blocks even if it incurs a negative carryover on its opex

- the AER agrees with the AEMC's views that, combined with other elements of the building block approach and the incentive mechanism framework, Powercor will be able to adequately fund and meet their service obligations. In this regard, the AER notes that as Powercor's accrued negative carryover amounts from 2001–05 regulatory period has only been offset against the positive carryover amounts from the 2006–10 regulatory period.

Consistency with AER's application of the NER

In its draft decision the AER rejected JEN's proposal that it be compensated for financing costs associated with the overspend of its capex allowance for 2006–10. However, Powercor argued that this was inconsistent with its decision to apply the 2001–05 negative carryover amount from Powercor's revenue requirements.

The AER considers that these are two separate and unrelated issues The AER's decision to reject JEN's proposal for compensation in relation to its financing costs was made in accordance with the NER, which does not allow the AER to make such adjustments to JEN's opening RAB.[73] In contrast, the AER considers that its decision to deduct Powercor's 2001–05 accrued negative carryover amounts from Powercor's 2006–10 positive carryover amounts is fully in accordance with the NER, as well as the NEL as noted above.

AS noted above, the AER considers that, in accordance with clause 6.4.3 of the NER and the EBSS, the AER has the authority to apply carryover amounts that have arisen from existing efficiency carryover schemes currently operating in state or territory jurisdictions in its first revenue determination for the relevant DNSPs. As noted above, the AER considers that the ECM, being the existing efficiency carryover scheme currently operating in Victoria, provides the regulator with discretion to offset negative carryover amounts accrued by Powercor in the 2001–05 regulatory period against future positive carryover amounts. In contrast, in relation to compensation for JEN's financing costs, in its draft decision, the AER identified that there are no provisions in chapter 6 of the NER, nor schemes or guidelines made in accordance with chapter 6, which provide the AER with authority to address financing costs associated with capex overspends during the current regulatory period.[74] Accordingly, even though the AER recognises that the ESCV in its 2006 EDPR did suggest that the regulator in the 2011–15 regulatory period would perform an ex post assessment of actual capex spent by all Victorian DNSPs for the 2006–10 regulatory control period, the AER has no authority to do this under the NEL and NER.

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[73] AER, *Vic Draft Decision*, June 2010, p. 449.
[74] ibid.

The AER reiterates that its draft decision to reject JEN's proposal for compensation for financing costs associated with capex overspend does not relate to any existing carryover scheme. Rather, it was in relation to the RAB roll forward for the 2011 opening RAB. Despite the ESCV's expectations in its 2006 EDPR that the AER could roll these financing costs into the RAB, the AER considers that there are no provisions in the NER which give it authority to roll these costs into JEN's opening RAB.

13.5.2.4 AER conclusion

The AER maintains its decision to apply the 2001–05 negative carryover amounts to Powercor's revenue requirement for each year of the forthcoming regulatory control period, 2011–15.

13.5.3 CitiPower's Net Present Value approach

13.5.3.1 AER draft decision

The AER considered that it is required to calculate and apply the carryover amounts in its determinations for the Victorian DNSP's (this includes CitiPower) in accordance with the requirements of the NER, EBSS and the ESCV's ECM as set out in the 2006 EDPR.

13.5.3.2 Victorian DNSP revised regulatory proposals

CitiPower proposed a zero carryover amount to be included in the 2011–15 regulatory control period under the 'NPV approach'.[75]

CitiPower considered the AER's decision to reject its net present value (NPV) approach (that is, apply a zero floor) is unreasonable and inconsistent with:

- the ESCV's reasoning in its 2006 EDPR, where it adopts a NPV approach for reasons that are equally applicable to the AER's decision
- the NEO, the revenue and pricing principles and the objectives of the ECM and the EBSS.[76]

CitiPower argued that the ESCV's 2006 EDPR, the AER's EBSS nor the NEVA can authorise the AER to act in a way that is beyond its powers under the NEL and NER, and the enforcement powers under the NEVA do not apply.[77]

CitiPower contended that the AER is required to make a decision under clause 6.4.3(a)(6) of the NER, having regard to the NEO, the revenue and pricing principles and the objectives of the ECM and EBSS.[78]

CitiPower also argued that adopting the NPV with a zero floor approach is consistent with the objectives of the ECM and ensures that CitiPower's revenue requirement will not be less than is required by an efficient business. In addition, CitiPower argued that the NPV approach is consistent with the requirements of the revenue and pricing

75 CitiPower, *Revised regulatory proposal*, p. 371; p. 389.
76 ibid., p. 371; pp. 387–89.
77 ibid., p. 371; p. 388.
78 ibid., p. 388.

principle in clause 7A(2) of the NEL and with the objectives of the EBSS under clause 6.5.8(c).[79]

13.5.3.3 Issues and AER considerations

The AER does not agree with CitiPower that its decision to reject CitiPower's NPV approach is unreasonable and inconsistent with the reasoning in the ESCV's 2006 EDPR.[80]

AER's decision in accordance with its power under the NEL and NER

As noted in section 13.5.2.3 the AER agrees with CitiPower that the NEVA does not apply in considering the application of the ESCV's ECM to CitiPower for the 2011–15 regulatory control period. However, the AER does not agree with CitiPower that the draft decision's rejection of CitiPower's zero floor approach to calculate the carryover amounts is inconsistent with the NEO, the revenue and pricing principles and the objectives of the ECM and the EBSS.

As noted in section 13.5.2.3, the AER is authorised to apply efficiency carryover amounts as part of the building block determination in accordance with 6.4.3 of the NER. Clause 6.4.3(a)(5) and (b)(5) of the NER set out that revenue increments and decrements that arise as a result of an applicable EBSS as referred to in clause 6.5.8 are a component of the building block determination. The applicable EBSS was published in June 2008 under clause 6.5.8(a). Section 2.3.4 of the EBSS states:

> Subject to the adjustments noted in section 2.3.2 of this document, the AER will apply all carryovers both positive and negative. Carryover amounts will be included as a building block element in the calculation of a DNSP's allowed revenue for the regulatory control period following the regulatory control period in which the EBSS applied.[81]

In regard to the transition to new national regime, the EBSS final decision published with the EBSS states:

> The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.[82]

The prevailing jurisdictional arrangements that apply to the Victorian DNSPs are detailed in the ESCV's ECM which determines the efficiency carryover amounts for

79 ibid.

80 The ESCV adopted an NPV approach with a zero floor. Under the ESCV's zero floor approach, a negative carryover amount was not applied to the revenue requirement for the 2006–10 regulatory period, where the sum of the 2001–05 regulatory period was negative in NPV terms. Instead where the sum of the accrued negative carryover amounts for the 2001–05 regulatory period was negative in NPV terms, the efficiency carryover amount was set to zero for each year of the 2006–10 regulatory period. Conversely, where the sum of the accrued efficiency carryover amounts for the 2001–05 regulatory period was positive in NPV terms, the efficiency carryover amount was incorporated in the revenue requirement for the 2006–10 regulatory period.

81 AER, *Electricity DNSPs EBSS*, June 2008, p. 7.

82 AER, *Final decision, Electricity DNSPs' EBSS*, June 2008, p.13; AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, JEN, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, pp.105-112.

the forthcoming regulatory control period. Accordingly, the AER has calculated CitiPower's carryover amounts in accordance with the requirements of the NER, EBSS and the ESCV's ECM as set out chapter 10 of the 2006 EDPR and with regard to the NEO and revenue and pricing principles set out in the NEL. The AER considers this to be in accordance with its decision making authority under the NEL and the NER.

ESCV's reasoning in its 2006 EDPR

The AER notes that the ESCV in its 2006 EDPR considered the future treatment of efficiency losses. In particular, the ESCV stated that:

> The Commission has consulted on the treatment of negative carryover amounts during this price review and reaffirms that there will be **no zero floor** on negative carryover amounts in calculating the efficiency carryover amounts for the 2006-10 regulatory period that are to be applied in the 2011 regulatory period. [emphasis added][83]

Accordingly, the AER notes that the ESCV explicitly stated that the ECM will not include a zero floor approach (that is, an NPV approach), which is contrary to CitiPower's statement that ESCV adopted an NPV approach. The ESCV further stated that it removed the zero floor approach on the basis of the inability of the efficiency carryover mechanism to achieve its objectives.[84] These objectives included amongst other things to:

- encourage DNSPs to pursue efficiency gains throughout the regulatory control period

- reduce the incentive to defer the pursuit of efficiency gains that might otherwise exist immediately before a regulatory review.[85]

On this basis the AER consider that its decision to reject CitiPower's proposal to apply a zero floor is reasonable and consistent with the ESCV's reasoning in its 2006 EDPR.

Consistency with the NEO, the revenue and pricing principle and objectives of the ECM and EBSS

In making this decision, the AER has had regard to the National Electricity Objective and the revenue and pricing principles and the NER. The AER considers that the application of a symmetrical treatment of efficiency gains and losses within the regulatory control period, is consistent with clause 6.5.8 of the NER, the NEO and the revenue and pricing principles.

Firstly, the adoption of a zero floor approach would require any negative carryover that could not be offset against positive carryover amounts to be accrued and offset against future positive carryover amounts. However as noted by the ORG:

> ….carrying over an accrued negative carryover in full from one regulatory period to the next may dampen incentives to achieve efficiencies in the new

83 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 434
84 ibid,, p. 424
85 ibid., p. 415

> regulatory period, especially when the accrued negative carryover is significant.[86]

The AER also in its EBSS final decision stated that:

> The AER proposed that the EBSS would operate on a symmetric basis and all carryover, both positive and negative, would be applied and carried over for the duration of the carryover period. This would ensure constant and symmetric incentives.[87]

The AER's EBSS also states in section 2.3.4 of the EBSS, that the AER will apply all carryovers, both positive and negative.[88] The AER notes that the EBSS was published under clause 6.5.8 of the NER. The objectives under 6.5.8 of the NER include amongst other things:

- the need to provide DNSPs with a continuous incentive to reduce operating expenditure (clause 6.5.8(c)(2)

- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses (clause 6.5.8(c)(3).

Accordingly, the AER considers that where a zero floor approach is adopted, the Victorian DNSPs may not be provided with an incentive to achieve continuous incentives in accordance with cl. 6.5.8(c)(2) of the NER and this is not consistent with clause 6.5.8(c)(3) of the NER. The AER considers that any dampening of incentives to seek efficiencies is also not consistent with NEO, given that the NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long time interest of consumers of electricity.

In particular, where negative carryover amounts are only offset against positive carryover amounts, this will reduce the incentive for a DNSP to continuously pursue efficiency improvements as the penalty for any net inefficiency (that is, where efficiency losses are greater than efficiency gains) these losses are 'capped' at zero. This means that a DNSP will not be exposed to the full penalty associated with any efficiency losses. The AER in its explanatory statements that accompanied the EBSS did not consider it appropriate to cap net negative carryovers.[89] The AER considered that a DNSP approaching the cap, if this was in place, would no longer have a continuous incentive to reduce opex because any positive carryover achieved, if any, will be used to offset the deferred negative carryover (that is, a DNSP would not be exposed to the full penalty associated with the efficiency loss). Furthermore, DNSPs that have accrued a net negative amount as a result of incurring a greater amount of efficiency losses than gains within the regulatory control period would have a stronger incentive to shift costs into the penultimate year in order to increase future period opex forecasts (where the AER places significant weight on the penultimate year to assess A DNSP's opex forecast as is the case for this review).

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86 ORG, *Electricity Distribution Price Determination 2001–05 Volume. 1 Statement of Purpose and Reasons*, pp.89–90

87 AER, *Final decision, Electricity DNSPs' EBSS*, June 2008, p. 5.

88 AER, *Electricity DNSPs' EBSS*, June 2008, p. 7.

89 AER, *Explanatory statement, Proposed electricity DNSPs' EBSS,* April 2008, pp. 8–9.

The zero floor approach is also inconsistent with clause 6.5.8(c)(2) which requires that the AER considers the desirability of rewarding DNSPs for efficiency gains and penalising the DNSPs for efficiency losses. The AER considers that as a symmetrical approach will provide greater incentives for a DNSP to pursue efficiency savings over a regulatory control period. Accordingly, the AER considers under a symmetrical approach, the long term benefits to customers will outweigh any higher prices in the short term associated with the carryover of efficiency gains given that DNDP will have a greater incentive to pursue efficiency savings and not incur efficiency losses.

Further any dampening of incentives to seek future efficiencies on the basis of the AER's reasoning discussed above would also not be consistent with section 7A(3) of the NEL in terms of promoting incentives for the efficient operation and delivery of distribution services. The AER also notes that any dampening of incentives to pursue efficiency savings will not promote the NEO as this will result in customers experiencing higher network prices than necessary. Moreover, where the AER places significant weight on a DNSP's actual opex to establish a DNSP's forecast opex, given the incentive to defer or shift expenditure to the base year, customers will experience higher network prices than necessary over time.

The AER also considers that including negative carryover amounts in CitiPower's amounts for the 2011–15 regulatory control period is consistent with the 7A(2) of NEL. The AER in its explanatory statements accompanying the EBSS noted that:

> any carry-over amounts from one year are combined with others and the net amount is spread over several years in the following regulatory control period. The negative effect of a decrement in one year can be negated by a more efficient performance in later years. Where multiple decrements result in a net negative carry-over amount, operating expenditures are combined with four other building blocks. Thus, the overall revenue permitted may still be commensurate with, and provide a reasonable opportunity for a DNSP to recover, the efficient costs of complying with regulatory obligations.
>
> The AER notes that the revenue principle does not establish a floor under a DNSP’s revenue. Rather, it requires that the DNSP be provided a ‘reasonable opportunity’ to recover the efficient costs of complying with its regulatory obligations. In developing the EBSS the AER has sought to minimise the risk of negative carry-overs resulting from opex variations beyond the control of DNSPs. Consequently, the AER considers that the EBSS and revenue determination process will provide DNSPs with a ‘reasonable opportunity’ to recover its efficient costs.[90]

Accordingly, the AER considers that including negative carryover amounts in CitiPower's building block revenue for the 2011–15 regulatory control period is consistent with the 7A(2) of NEL, which requires the DNSPs to be provided with a reasonable opportunity to recover its efficient costs.

As discussed in section 13.5.2.3, the AER is also cognisant of the views expressed by the AEMC regarding the issue of negative carryover amounts and the requirements of the revenue and pricing principles.[91] The AER concurs with the views of the AEMC,

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[90] AER, *Explanatory statement, Proposed electricity DNSPs’ EBSS*, April 2008, p. 8.

[91] AEMC, *Rule Determination–National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18*, November 2006, pp. 96–97.

and notes that these views apply equally to both TNSPs and DNSPs in terms of the EBSS. In particular, the AEMC made no distinction between TNSPs and DNSPs in terms of the EBSS in its review of the electricity revenue and pricing principles. Therefore, the AER considers that the application of CitiPower's negative carryovers is consistent with the NEO, the revenue and pricing principles and the NER.

In conclusion, the AER considers non-application of the NPV approach and the adoption of a symmetrical treatment of efficiency gains and losses to determine CitiPower's carryover amounts is consistent with:

- the approach of the ESCV to determine the Victorian DNSPs carryover amounts for the 2011-15 regulatory control period as set out in chapter 10 of its 2006 EDPR
- the AER's EBS final decision published under clause 6.5.8 of the NER which adopted a symmetrical treatment of efficiency gains and losses
- achieving the objective of providing CitiPower with continuous incentives to seek efficiency savings consistent with the EBSS, under 6.5.8 (c) (2) of the NER
- achieving the objective of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses, consistent with EBSS, under 6.5.8 (c) (3)of the NER.
- promoting effective incentives for the delivery of standard control services consistent with the 7A(3) of the NEL.
- providing incentives to CitiPower to seek efficiencies, consistent with the NEO, to promote efficient investment in, and efficient operation and use of, electricity services for the long time interest of consumers of electricity.

13.5.3.4 AER conclusion

The AER maintains its draft decision to include CitiPower's negative carryover amounts in the 2011–15 regulatory control period.

13.5.4 Ex post adjustments to the benchmark allowance associated with network growth

13.5.4.1 AER draft decision

The Victorian DNSPs proposed to apply growth adjustments to the ESCV benchmark 2006–10 allowances. The AER identified some inconsistencies with the growth adjustments as specified by the ESCV in its 2006 EDPR. The AER corrected these errors and omissions and this has resulted in minor adjustments to the ECM calculations for each Victorian DNSP.

13.5.4.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor accepted that an adjustment should be made in relation to network growth. However, CitiPower and Powercor stated that they did not accept the

AER's estimated 2010 volume inputs for this adjustment because both DNSPs did not accept the AER's approach to scale escalation.[92]

SP AusNet rejected the AER's use of the growth adjustment formula, on the basis that this:

- leads to both intuitive and theoretically incorrect outcomes
- does not reflect the modelling approach adopted by the ESCV to derive the operating and maintenance expenditure benchmark allowances included in the 2006 Final Decision
- does not reflect the actual impact of growth on SP AusNet’s costs within the regulatory control period.[93]

SP AusNet contended that the AER’s growth adjustment calculation is invariant to the timing of growth as a result of the AER taking a simple average of the different growth rates over the entire period, which is inconsistent with the ESCV's approach.[94] SP AusNet stated that the AER’s methodology is inconsistent with methodology used by the ESCV when formulating the 2006 Final Decision, as it produces substantially different results than if the year on year growth rates were inputted into the ESCV’s own Final Decision model.[95] SP AusNet submitted that that the growth adjustment should instead be based on the difference between 2006 actual expenditure and 2005 forecast expenditure – not 2006 actual expenditure and 2005 actual expenditure. SP AusNet contended that the AER's approach to be incorrect for two reasons:

- ‘intuitively correct’ results, as it removes the scenario whereby a negative growth adjustment is applied to a business’ O&M benchmarks, despite 2006 actual outputs being greater than 2006 forecast outputs
- theoretically incorrect, given how the ESCV in fact calculated their growth adjustment. In particular, given that the 2005 actual figures were irrelevant in developing the 2006 benchmarks, they are also irrelevant for the derivation of the growth adjustment.[96]

SP AusNet submitted that the 2010 forecasts should be excluded from the derivation of the growth adjustments that are applied to the 2006–2009 period. In addition, SP AusNet submitted that the AER has made an error of fact in its assessment of the ESCV’s model and the AER’s methodology is inconsistent with the requirements outlined in Section 7A of the NEL.[97]

92 CitiPower, *Revised Regulatory Proposal*: *2011 to 2015*, 21 July 2010, p. 385; Powercor, *Revised Regulatory Proposal*: *2011 to 2015*, 21 July 2010, p. 384

93 SP AusNet, *Revised Regulatory Proposal*: *Electricity Distribution Price Review 2011–2015*, July 2010, p. 290.

94 ibid., pp. 284–85.

95 ibid., pp. 285–88.

96 ibid., pp. 288–89.

97 ibid., p. 290.

13.5.4.3 Issues and AER considerations

The AER considers in making adjustments to the benchmark allowance associated with network growth, the AER is calculating carryover amounts in accordance with the ESCV's ECM set out in chapter 10 of its 2006 EDPR. As discussed in 13.5.2.3, the AER is making its 2011–15 revenue determination for Victorian DNSPs under the regulatory framework of the NEL and the NER. In accordance with the EBSS final decision made under 6.5.8 of the NER, the AER is required to apply the EBSS to the Victorian DNSPs for the 2011–15 regulatory control period. The EBSS allows the AER to calculate and apply carryover amounts for the forthcoming regulatory control period from, and in accordance with, existing jurisdictional schemes, in this case the ESCV's ECM.[98]

CitiPower and Powercor

CitiPower and Powercor's submitted that they did not accept the AER's estimated 2010 volume inputs for this adjustment because both DNSPs did not accept the AER's approach to scale escalation. The AER notes that the ESCV growth formula includes three components- customer numbers, peak demand and energy. Whereas, the AER's approach for scale escalation for the 2011–15 regulatory control period has adopted customers numbers, capacity of zone substations, line length and the number of transformers as drivers (that is, components) of network growth. The AER notes that the customer number component is the only component that is common between these two approaches. In applying the ESCV's growth adjustment the AER has accepted CitiPower and Powercor's estimate of customer numbers for 2010 in this final decision such that 2010 volume inputs for the customer number component reflect CitiPower and Powercor's revised proposals.

In addition, the AER notes that the remaining components utilised in the ESCV growth formula do not align with the AER components used to determine the Victorian DNSPs scale escalation. Accordingly, the AER does not consider CitiPower and Powercor's statement is relevant for the remaining components (or volume inputs) to be applied to the growth adjustment to the ECM, given that the:

- scale adjustment is related to forecasts opex for the forthcoming regulatory control period, and
- growth adjustment to ECM is related to the adjustment to the benchmark opex allowance for the current regulatory period.

SP AusNet

In its 2006 EDPR, the ESCV proposed the establishment of a method for adjusting the expenditure benchmarks for differences between actual and forecast demand growth when calculating the efficiency carryover amounts for the 2011–15 regulatory control period.[99] The AER noted in the draft decision that the ESCV stated that establishing a method for future growth adjustments provides greater certainty to the Victorian DNSPs and other stakeholders on the calculation of the efficiency carryover amounts in the 2011–15 regulatory control period.[100] The AER also noted that all Victorian

98 AER, *Electricity DNSPs EBSS*, June 2008, p. 13.
99 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 435.
100 ibid.

DNSPs, including SP AusNet, stated that they applied a growth adjustment using the growth adjustment method determined by the ESCV over the 2006–10 regulatory period.[101]Accordingly, the AER adopted the same growth adjustment formula specified by the ESCV in its 2006 EDPR (as restated in section 13.5.3 of the draft decision) to calculate the carryover amounts for the 2011–15 regulatory control period.

The AER does not agree with SP AusNet that the AER has made an error of fact in its assessment of the ESCV's model, given that the AER has applied exactly the same growth adjustment methodology as determined by the ESCV's 2006 EDPR.

SP AusNet contended that AER's growth adjustment is intuitive and theoretically incorrect because the AER's model produces negative growth adjustments, even when actual outputs have been greater than forecast outputs for each year of the 2006–10 period. More specifically, SP AusNet contended that the AER's growth adjustment in fact leads to a negative growth adjustment for its customer number parameter, although actual customer numbers have exceeded the 2006 EDPR forecast in each year of the 2006–10 period.[102] In response the AER has applied the ESCV's growth adjustment formula, consistent with the growth adjustment formula applied to the benchmark allowance. The AER notes that ESCV's growth adjustment formula is determined by the following steps:

- first, this formula calculates an annual weighted average growth rate (natural log growth) of actual customer numbers, actual peak demand and actual energy consumption over 2005–10
- second, this formula calculates a simple average growth rate for 2006–10 of the annual weighted average of customer numbers, peak demand and energy consumption
- third, the incremental growth is calculated by comparing the benchmark allowance for growth and the actual growth as calculated in step two.

The AER notes that the customer number component is only one of the three components to be adjusted for network growth. This means that given the ESCV's growth adjustment calculation as explained above, actual positive customer number growth in each year exceeding the 2006 EDPR benchmark does not necessarily warrant a positive growth adjustment as the contribution of the other growth components will affect the outcome.

SP AusNet contended that the AER's growth adjustment calculation is invariant to the timing of growth as a result of the AER taking a simple average of the different growth rates over the entire period, which is inconsistent with the ESCV's approach.[103] The AER disagrees that the growth adjustment calculation applied in the draft decision is invariant to the timing of growth and that the AER's use of a simple

[101] CitiPower, *Regulatory proposal*, p. 250; Powercor, *Regulatory proposal*, p. 254; JEN *Regulatory proposal*, p. 208; SP AusNet, *Regulatory proposal*, p. 264; United Energy, *Regulatory proposal*, pp. 164–65.

[102] SP AusNet, *Revised Regulatory Proposal*: *Electricity Distribution Price Review 2011–2015*, July 2010, p. 283–84.

[103] SP AusNet, *Revised Regulatory Proposal*, pp. 284–85.

average is inconsistent with the ESCV's approach. As explained above, the AER has adopted a growth adjustment consistent with the 2006 EDPR, which calculates annual growth rate for 2006–10 and is variant to timing of growth.[104]

The AER also disagrees with SP AusNet's statement that the AER's application of the growth formula is inconsistent with the growth formula set out in the 2006 EDPR and the AER's growth adjustments provided substantially different results from the 2006 EDPR growth formula.[105]The AER has adopted the 2006 EDPR growth adjustment methodology that was applied by the ESCV to determine the benchmark allowance. The AER also noted in the draft decision that all Victorian DNSPs, including SP AusNet, applied an incorrect growth averaging formula as the impact of growth for each component was not compounded for each year of the current regulatory period.[106]

The AER disagrees with SP AusNet that the growth adjustment should instead be based on the difference between 2006 actual and 2005 forecasts (rather than the difference between 2005 and 2006 actual expenditure) given that SP AusNet's proposed approach does not reflect the ESCV's growth formula specified in its 2006 EDPR. On the same basis, the AER disagrees with SP AusNet that the 2010 forecasts should be excluded from the derivation of the growth adjustments that are applied to the 2006–2009 period, given that SP AusNet's proposed approach is not consistent with the 2006 EDPR.

In summary, the AER notes that under SP AusNet's preferred approach, the benchmark allowance and the actual operating expenditure adjustment for network growth can not be compared 'like for like' as the ESCV's benchmark allowance was set on the basis of the ESCV's growth adjustment method.[107]

The AER does not agree with SP AusNet that AER’s growth adjustment methodology is inconsistent with the requirements outlined in Section 7A of the NEL, in particular the clause 7A(2) of the NEL. The AER has adopted the growth adjustment methodology which reflects the growth formula set out in the 2006 EDPR so that the benchmark allowance and actual operating expenditure adjustment for network growth can be compared 'like for like' in calculating the efficiency carryover amounts. The AER notes that it has some discretion as to whether to apply the ESCV's growth

104 The AER has applied the ESCV's growth formula which is to calculate an annual weighted average growth over the period 2005–10.

105 The AER notes there is a discrepancy between the forecast customer numbers in the ESCV's 2006 EDPR and the ESCV's model used to forecast customer numbers in its 2006 EDPR for SP AusNet. The AER also notes that based on the approach as described in the ESCV's 2006 EDPR, the ESCV's model applies an incorrect averaging of customer numbers, energy consumption and peak demand to determine the annualised weighted average growth. The AER has applied the forecast customer numbers in the ESCV's 2006 EDPR and the correct growth averaging method as described in the 206 EDPR to determine SP AusNet's adjustments to the ESCV benchmark allowance for growth.

106 AER, *Vic Draft Decision*, June 2010, p. 582.

107 ESCV in its 2006 EDPR (p. 419) stated that to determine the carryover amounts to be included in the revenue requirement, the ESCV must ensure reported costs are compared to the expenditure benchmarks in order to measure efficiencies over the regulatory period. For the rewards implicit in the efficiency carryover to reflect the cost of providing the distribution services, it is important that the reported expenditure information is calculated on the same basis as the expenditure forecasts against which it is compared, which is like for like.

adjustment formula if the adjustment leads to a negative carryover, as discussed in 13.5.1. However the AER does not consider that applying a negative growth adjustment to the benchmark allowance which contributes to any negative efficiency carryover amounts is inconsistent with the 7A(2) of the NEL, which requires the DNSPs to be provided with a reasonable opportunity to recover efficient costs. The AER's reasoning is detailed in sections 13.5.2.3 and 13.5.3.3 regarding the consistency between negative carryover amounts and section 7A(2) of the NEL. In this context the AER notes that the:

- impact of the growth adjustment on the efficiency carryover amounts only accounts for small proportion of the total ECM and
- ECM applies only to the operating and maintenance expenditure component of the building block revenue allowance
- Victorian DNSPs will still be receiving revenues from all other components of the building blocks even if it incurs a negative carryover on its opex.

In making the decision to apply the ESCV's growth adjustment to the ECM consistent with the 2006 EDPR, the AER has had regard to the National Electricity Objective and the revenue and pricing principles. The AER by applying the ESCV's growth adjustment to the ESCV benchmark allowance is maintaining comparability between the ESCV benchmark allowances and actual opex. The AER considers that this ensures that the Victorian DNSPs will only be rewarded for underlying efficiencies achieved over the 2006–10 regulatory period. That is the Victorian DNSPs will not receive an efficiency gain or loss as a result of external network growth. The AER considers that this is in the long term interests of customers given that customers will only share with the Victorian DNSPs, the internal efficiencies that have been achieved. The AER also considers that this is consistent with the section 7A(3) as this ensures that the Victorian DNSP's will not have a disincentive from efficiently utilising or expanding its network in the delivery of standard control services, where there may be differences between actual and assumed network growth. The AER considers applying the growth adjustments to the ECM as specified in the 2006 EDPR will also promote regulatory certainty which is in the long term interests of customers consistent with the NEO.

That said the AER notes that it has applied the growth formula in the ESCV's ECM as specified in its 2006 EDPR and as previously discussed the AER is implementing the ECM in accordance with the AER's EBSS final decision. The AER also notes that the EBSS final decision was developed and published under clause 6.5.8 of the NER and the AER did not receive any comments from CitiPower, Powercor and SP AusNet on any aspect of the ESM during this consultation process.

13.5.4.4 AER conclusion

The AER maintains it draft decision to apply the ESCV's growth adjustment formula to calculate the efficiency carryover amount for the Victorian DNSPs. The AER has updated the growth adjustment calculations used to calculate the carryover amounts in the draft decision using the 2009 actual expenditure for customer numbers, energy consumption and peak demand for the final determination. The AER's growth adjustment for the Victorian DNSP's is provided in table 13.3.

Table 13.3 AER conclusion on impact of growth on annual benchmark opex, 2006-10 ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower	–0.23	–0.45	–0.68	–0.90	–1.13
Powercor	0.61	1.22	1.83	2.45	3.07
JEN	0.10	0.21	0.31	0.41	0.52
SP AusNet	–0.18	–0.36	–0.54	–0.72	–0.90

Source: AER analysis.

13.5.5 AER adjustments to ESCV benchmark allowance and actual opex

13.5.5.1 AER draft decision

The AER identified a number of adjustments that it considered to be necessary to ensure a ‘like for like’ comparison between the benchmark allowance and actual expenditure in calculating the efficiency carryover amounts for 2006–10. These adjustments and the AER's conclusions are set out below.

Capitalisation of overheads

The Victorian DNSPs (with the exception of JEN) stated that there had been no change in their capitalisation policies over the regulatory period.

The AER included JEN's proposed reduction in capitalised indirect overheads of $4.34 million ($2010) for 2008 and 2009 as a placeholder in the draft decision, as JEN did not provide information to substantiate its proposed reduction to indirect overheads.

The ESCV in establishing the benchmark allowance for SP AusNet assumed that there is no capitalisation of indirect (corporate) overheads. The AER noted, however, that in SP AusNet’s regulatory accounts and RIN that SP AusNet had capitalised some of its indirect overheads. The AER adjusted the ESCV benchmark allowance for SP AusNet to ensure that the actual expenditure and the ESCV benchmark allowances are compared on a ‘like for like’ basis in measuring the carryover amounts for the 2006–10 regulatory period.

The AER stated that it would review the Victorian DNSPs’ regulatory accounts for 2009 in its final decision regarding any changes to capitalisation of indirect overheads.

Movement in provisions

The Victorian DNSPs (with the exception of CitiPower and Powercor) did not propose to remove the impact of the movement in provisions in their proposed carryover amounts. The AER made minor amendments to CitiPower and Powercor's reported expenditure for the movement in provisions for 2006–09. The AER also adjusted SP AusNet's movement in provisions for an assumed allocation of costs between its gas and electricity businesses and JEN's expenditure for miscellaneous provisions. The AER also required SP AusNet to verify the AER's assumed allocation of costs related to its movement in provisions for 2006–09.

The AER stated that it would review the Victorian DNSPs' regulatory accounts for 2009 in its final decision and update if necessary for any movement in provisions.

Treatment of related party margins

The AER noted that the ESCV in deriving its benchmark allowances for the 2006–10 regulatory period excluded related party margins (referred to as contractual arrangements). The AER therefore excluded the related party margins in 2006 in the carryover amounts for the Victorian DNSPs to ensure that actual expenditure and the ESCV benchmark allowance was compared 'like for like'.

Other adjustments

The AER also considered a number of adjustments proposed by the Victorian DNSPs including the licence fees, AMI reclassification (CitiPower and Powercor only) and for non-network activities (JEN only).

The AER made some adjustments to JEN and SP AusNet proposed carryover amounts to exclude the costs of licence fees from actual expenditure where appropriate.

CitiPower and Powercor proposed further adjustments to their audited regulatory accounts to confirm the AMI expenditure and revenues proposed to the AER for 2006–08. The AER did not accept these further amendments to its regulatory accounts on the basis it would only accept the audited regulatory accounts (in this case the re-audited regulatory accounts). Accordingly, the AER adjusted CitiPower and Powercor's carryover amounts where the allocation of costs related to AMI was inconsistent with CitiPower and Powercor's re-audited regulatory accounts.

JEN proposed to exclude expenditure related to avoided distribution use of system costs paid to embedded generators in the calculation of carryover amounts. However, as the ESCV benchmark allowance included these costs, the AER dos not accept the exclusion of these costs from actual expenditure as proposed by JEN.

13.5.5.2 Victorian DNSP revised regulatory proposals

Capitalisation of overheads

SP AusNet submitted that it did not agree with the AER's indirect corporate overheads adjustments in relation to the calculation of the efficiency carryover amounts for the 2006–10 regulatory period, on the basis that:

- the underlying definition of 'indirect (corporate) overheads' used by the AER in assessing this issue is materially different to the definition that underpinned the statement attributed to the ESCV in their final decision
- there has been no change in SP AusNet's capitalisation policy since 2001
- the AER's regulatory information notice (RIN) did not seek to capture information that would in fact allow it to make a 'like for like' comparison for the purposes of calculating carryover amounts for the 2006–10 regulatory period, therefore, SP

AusNet has not previously had the opportunity to provide any relevant information on this material issue.[108]

The AER's draft decision adjusted for JEN's change in capitalisation policy during the current regulatory period. It also requested that JEN provide further information explaining this change.[109] JEN has provided additional information regarding its 2008 change in capitalisation policy in its revised regulatory proposal.[110]

Movement in provisions

CitiPower and Powercor did not agree with the amount of the AER's adjustments in the draft decision in relation to provisions.[111] CitiPower and Powercor submitted that the provisions relating to customer refunds (2008) and employee entitlements (2006–09) were incorrect, on the basis that:

- the provision statement for customer refunds in the 2008 regulatory accounts is incorrect
- the draft decision used the unaudited 2009 regulatory accounts to calculate the provision movement, which differed the final 2009 regulatory accounts employee entitlement provision statement
- the draft decision allocated the employee entitlement provisions based on the labour costs of for the licensee whereas it should be based on the labour costs of the organisation
- the draft decision allocated the entire employee entitlement provision movement between capex and opex. However the long service leave provision for 2008–2009 should remain allocated to opex as per the income statement.[112]

In addition, Powercor submitted that the provisions in the draft decision relating to stock written down (2008) and vegetation management (2006–07) were also incorrect, on the basis that:

- the provision statement for stock written down contained in the 2008 was incorrect
- vegetation management adjustment (2006–07) was excluded in the draft decision.[113]

Both CitiPower and Powercor have provided their provision adjustments with an audit sign off.

108 SP AusNet, *Revised regulatory proposal*, p. 278.
109 AER, *Vic Draft Decision*, June 2010, p. 585.
110 JEN, *Revised regulatory proposal*, pp. 272–74.
111 CitiPower, *Revised* r*egulatory proposal*, pp. 385–87; Powercor, *Revised* regulatory *p*roposal, pp. 385–87.
112 CitiPower, *Revised* r*egulatory proposal*, pp. 385–87; Powercor, *Revised regulatory proposal*, pp. 385–87.
113 Powercor, *Revised regulatory proposal*, p. 386.

The other Victorian DNSPs did not raise an issue with the AER's draft decision regarding the adjustments to provisions.

Related party margins

CitiPower and Powercor accepted the AER's adjustments to the 2006–10 carryover amounts in relation to related party margins and AMI reclassification.[114] No other Victorian DNSPs commented on the AER's draft decision to remove related party margins in the calculation of the efficiency carryover amounts.

Other adjustments

CitiPower and Powercor accepted the AER's adjustments to the 2006–10 carryover amounts in relation to AMI reclassification.[115]

CitiPower and Powercor accepted an adjustment should be made in relation to licence fees, but neither of the DNSPs accepted the amount of the AER's proposed adjustment.[116]

No other Victorian DNSPs raised an issue on the AER's adjustments to the 2006–10 carryover amounts in relation to licence fees.

13.5.5.3 Issues and AER considerations

The AER considers in making the following adjustments to the ESCV benchmark allowances or actual opex, the AER is calculating carryover amounts in accordance with the ESCV's ECM's 'like for like' principle as discussed in chapter 10 of its 2006 EDPR. As discussed in 13.5.2.3, the AER is making its 2011–15 revenue determination for Victorian DNSPs under the regulatory framework of the NEL and the NER. In accordance with the EBSS final decision made under 6.5.8 of the NER, the AER is required to apply the EBSS to the Victorian DNSPs` for the 2011–15 regulatory control period. The EBSS allows the AER to calculate and apply carryover amounts for the forthcoming regulatory control period from, and in accordance with, existing jurisdictional schemes, in this case the ESCV's ECM.[117]

Capitalisation of indirect overheads

The AER in the draft decision included JEN's proposed reduction in capitalised indirect overheads of $4.34 million ($2010) as a placeholder in the draft decision as JEN did not substantiate its proposed adjustment of $4.34 million for 2008.[118] The AER also noted in its draft decision that the reduction of the amount of corporate indirect overheads of $4.34 million for 2009 was an estimate and would need to be updated based on 2009 audited actual expenditure.[119]

In response to the AER's draft decision, JEN provided further information regarding JEN's capitalised indirect overheads in relation to is original capitalisation policy before the adoption of its new capitalisation policy introduced in 2008.[120] JEN also

114 CitiPower, *Revised* r*egulatory proposal*, p. 389; Powercor, *Revised regulatory proposal*, p. 387.
115 CitiPower, *Revised* r*egulatory proposal*, p. 389; Powercor, *Revised regulatory proposal*, p. 387.
116 CitiPower, *Revised* r*egulatory proposal*, p. 385; Powercor, *Revised regulatory proposal*, p. 385.
117 AER, *Electricity DNSPs EBSS,* June 2008, p. 13.
118 AER, *Vic Draft Decision,* June 2010, pp. 584–85.
119 ibid., p. 585.
120 JEN, *Revised regulatory proposal - Appendix 13.2,* July 2010.

submitted that it has adopted the 2008 change in capitalised indirect overheads escalated for CPI as the proxy for the impact of its changed capitalisation policy for 2009. JEN stated this was necessary as JEN did not have information for 2009 to determine the amount of indirect overheads capitalised in 2009 under its original policy.[121]

The AER has reviewed the further information provided by JEN which confirms JEN's capitalised indirect overhead under its original capitalisation policy was $6.89 million (nominal) for 2008, consistent with its proposed ECM adjustment of $4.34m. The AER acknowledges JEN's position that it is unable to determine the precise adjustment for 2009 given the lack of information available for 2009. Accordingly the AER accepts JEN's capitalisation policy adjustments to the calculation of efficiency carryover amounts for 2008 and 2009.

The AER made adjustments to the ESCV benchmark allowance to take into account a change in SP AusNet's capitalisation of indirect (corporate) overheads over the regulatory period on the basis that:

- the 2006 EDPR indicated that all of SP AusNet's indirect overheads would be expensed (that is, there would be no capitalisation of indirect (corporate) overheads for the 2006–10 regulatory period

- SP AusNet's regulatory accounts and response to the AER's RIN accompanying SP AusNet's initial regulatory proposal indicated that SP AusNet did capitalise some of its indirect (corporate) overheads, whereas in contrast the ESCV benchmark allowance assumed that all indirect overheads will be expensed (i.e. there would be no capitalisation of indirect overheads).[122]

SP AusNet advised that the capitalised indirect overheads in the regulatory accounts and the information in the RIN reflected both direct and indirect overheads.[123] In the absence of information from SP AusNet, the AER assumed that 50 per cent of the total amount of 'indirect overheads' reported over the 2006–10 regulatory period is attributable to indirect overheads. The AER considered this adjustment was necessary to ensure a ‘like for like’ comparison between actual operating and maintenance expenditure and the ESCV benchmark allowance.[124]

In response to the draft decision, SP AusNet submitted that:

- the AER assumed 'indirect overheads' is same as 'indirect (corporate) overheads' by switching between using these terms

- the 2006 EDPR definition of 'indirect (corporate) overheads' was a reference to non network corporate costs, which at the time was TXU’s Australian Head Office costs

[121] JEN, *Revised regulatory proposal*, pp. 273–74.
[122] AER, *Vic Draft Decision*, June 2010, pp. 585–86.
[123] SP AusNet, *Response to AER information requested 29 March 2010*, 30 March 2010.
[124] AER, *Vic Draft Decision*, June 2010, p. 585.

- In the 2004 regulatory accounts, SP AusNet capitalised $26.8million of 'indirect overheads', which included directly related to construction activities.[125]

SP AusNet also submitted that there has been no change in its capitalisation policy in either the 2001–05 or the 2006–10 regulatory period. In addition, SP AusNet stated that SP AusNet has continued to capitalise indirect costs from the network's business that were not directly related to construction activities.[126]

The AER has also further reviewed SP AusNet's revised proposal on the 2006 EDPR's definition of indirect (corporate) overheads and acknowledges that the definition of 'indirect (corporate) overheads' for SP AusNet may not be the same as the indirect overheads which established the ESCV benchmark allowance.[127] The AER notes SP AusNet's statement that it capitalises indirect costs that are not directly related to construction activities. This is consistent with the observation that SP AusNet has capitalised a proportion of its indirect costs in the past and that it has not changed its capitalisation policy. In reviewing SP AusNet's regulatory accounting statements, the AER also accepts that SP AusNet appears to have consistently capitalised indirect overheads for 2001–05 and 2006–10 regulatory periods. Accordingly the AER accepts that SP AusNet has not changed its capitalisation policy for the 2006–10 regulatory period. The AER has not applied an adjustment to the ESCV benchmark allowance for SP AusNet for the final decision.

Movement in provisions

The AER has reviewed CitiPower and Powercor's proposed adjustments for movements in provisions in their revised proposals and accepts that the audited changes are consistent with CitiPower and Powercor's regulatory accounting statements.[128] The AER has also excluded from JEN's 2009 actual opex a movement in a 'doubtful debts provision' in the calculation of carryover amounts, consistent with JEN's regulatory accounting statement. JEN also proposed provision adjustments in relation to a redundant provision write-off. [129] The AER notes that these adjustments are related to a share of costs related to a one-off credit adjustment to write back redundant provisions from Jemena Limited’s balance sheet. The AER has accepted these costs on the basis of the information provided in JEN's revised regulatory proposal.

The AER noted in the draft decision that although SP AusNet provided some information regarding provisions prior to the draft decision, the AER was unable to fully reconcile this information to the 2006–2008 regulatory accounting statements. [130] The AER sought further information regarding movement in provisions for the period 2006–09 as SP AusNet did not provide any information in its revised regulatory proposal.[131] In reviewing SP AusNet's further information that was subsequently requested, the AER noted that some of SP AusNet's provision adjustments did not

125 SP AusNet, *Revised regulatory proposal*, pp. 278–79.
126 ibid., p. 279.
127 The AER has reviewed the ESCV's 2006 EDPR and the ESCV's Electricity Industry Guideline No.3 and has not been able to identify a definition of 'indirect (corporate) overheads'.
128 CitiPower, *Revised* r*egulatory proposal*, pp. 385–87; Powercor, *Revised regulatory p*roposal, pp. 385–87.
129 JEN, *Revised regulatory proposal*, p. 106.
130 AER, *Vic Draft Decision*, June 2010, p. 587.
131 AER, *Information request to SP AusNet - provisions 2005–2009*, 13 August 2010.

appear to be consistent with adjustments disclosed in SP AusNet's regulatory accounting statements[132] SP AusNet subsequently advised the AER that its proposed adjustments are consistent with its regulatory accounting statements and that it has complied with the regulatory accounting guidelines.[133]

The AER notes that clause 11.14.3(a) of the NER provides that reporting, monitoring and other compliance requirements continue under the existing regulatory regime until the end of the transitional regulatory period and (subject to this Part) are unaffected by the new regulatory provisions. This means that SP AusNet is required to comply with the ESCV's Guideline 3- electricity industry regulatory information requirements (Guideline 3).

The AER does not consider that SP AusNet has complied with Guideline 3, in relation to the provision's reporting requirements. In particular the AER notes that SP AusNet did not comply with the requirements to provide amongst other things a written explanation of the need for the provision adjustments and a written explanation of the movements in the provision under Guideline 3.[134] This means the AER is not able to establish whether SP AusNet's proposed provision adjustments are consistent with its regulatory accounting statements and so has accepted SP AusNet's proposed adjustments in calculating SP AusNet's carryover amounts. The AER will more closely scrutinise the Victorian DNSP's regulatory information in terms of compliance with any regulatory information instruments going forward.

Related party margin

The AER has reviewed ECM calculations proposed by all Victorian DNSPs and notes that related margins have been excluded in their revised ECM calculations.[135]

Other adjustments

Licence fees

The AER in the draft decision excluded licence fees from the calculation of the carryover amounts. However, AER excluded the Victorian DNSPs estimated licence fees for 2009 as the actual licence fees for 2009 were not available.[136] The Victorian DNSPs have subsequently provided the AER with their actual licence fees for 2009 included in their revised RIN or in response to the AER's information request.[137] The AER has accepted the actual licence fees for 2009 and excluded the 2009 actual licence fees from the calculation of the carryover amounts for the Victorian DNSPs.

AMI related adjustments

CitiPower and Powercor agreed with the draft decision to only apply AMI related adjustments consistent with their regulatory accounts in calculating their respective

[132] These provision adjustments related to 'current provision - uninsured losses'; 'current liabilities - provision - customer rebates'; 'non-current assets - superannuation'. These provisions appeared to be balance sheet items and not items related to SP AusNet's profit and loss account, such that no adjustments to opex would be necessary for these provision movements.

[133] SP AusNet, *SP management fee, provisions and other issues*, 8 September 2010.

[134] ESCV, *Templates for regulatory accounting statements-provisions*, 14 December 2006.

[135] JEN, *Revised* r*egulatory proposal,* A18.3 - JEN forecast data model; SP AusNet, *Revised regulatory proposal*, SP AusNet EBSS.

[136] AER, *Vic Draft Decision,* June 2010, pp. 588–89.

[137] CitiPower, Powercor, and JEN, revised RIN. SP AusNet, UED provided its actual licence fee in February 2010.

efficiency carryover amount.[138] The AER has therefore applied the adjustments in the draft decision for these costs in determining CitiPower and Powercor's efficiency carryover amounts.

Non-network activities

JEN did not comment on the AER's draft decision to not accept JEN's proposed adjustment to remove the costs of avoided distribution costs paid to embedded generators. The AER did not accept this adjustment on the basis that the ESCV benchmark allowance includes these costs.[139] The AER has maintained its draft decision and has not removed the costs of these activities in calculating JEN's efficiency carryover amounts.

Corporate costs

JEN accepted the AER's draft decision that its management fee paid to SPIAA is not sufficiently connected to the provision of JEN's distribution services.[140] The AER notes that in its revised proposal JEN also excluded this management fee from its 2009 costs for the purpose of calculating its efficiency carryover amounts. The AER accepts this adjustment for 2009 on the basis that these costs are not sufficiently connected to the provision of distribution services and would not have been included in the ESCV's benchmark allowance. However, the AER notes that JEN did not propose a corresponding adjustment to its efficiency carryover amounts for the fee incurred in 2008 and also for 2007 when these arrangements were established. The AER has therefore also removed the impact of these fees for 2007 and 2008 in calculating JEN's efficiency carryover amounts.[141] These adjustments are necessary to ensure a 'like for like' comparison between the ESCV benchmark and actual opex.

The AER also considers that JEN's corporate strategy costs are not sufficiently connected to JEN's provision of distribution services (refer to chapter 6 for the AER consideration of this issue). The AER for the same reasons as discussed has removed the impact of these costs from 2007–09 provided by JEN in calculating JEN's efficiency carryover amounts.[142]

Alternative control services

JEN proposed to include an amount on $0.2m from its carryover amount for costs associated with alternative control services in 2009. The AER has not accepted this adjustment to the carryover amount given this represents an update to JEN's costs associated with alternative control services. However, this proposed adjustment by JEN has been accepted in its base year amount (refer to chapter 7).

13.5.5.4 AER conclusion

The AER has reviewed the Victorian DNSPs' proposed carryover amounts and where necessary has adjusted the original ESCV benchmark allowance and the DNSPs' actual expenditure to ensure a ‘like for like’ comparison for the factors identified above. The AER considers that these adjustments are consistent with the NEO and section 7A(3) of the NEL and 6.5.8(c) of the NER. In particular the AER considers

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[138] CitiPower, *Revised regulatory proposal*, p. 385; Powercor, *Revised regulatory proposal*, p. 386.
[139] AER, *Vic Draft Decision*, June 2010, p. 589.
[140] JEN, *Revised regulatory proposal - A18.3 JEN forecast data model*, opex input sheet.
[141] JEN, *Response to AER information requested 8 September 2010*, 17 September 2010.
[142] ibid.

that these adjustments provide incentives for the Victorian DNSPs to pursue future cost reductions which is in the long term interests of customers and provides for a continuous incentive for the Victorian DNSP's to seek future efficiencies. The AER also considers that its adjustment to the ESCV benchmark for JEN's changed capitalisation policy takes into account the incentives to capitalise expenditure under the ESCV's ECM (6.5.8(c)(4)).

13.5.6 Treatment of uncontrollable and non-recurrent costs

13.5.6.1 AER draft decision

The AER did not accept adjustments to the ESCV's benchmark allowance for uncontrollable costs or adjustments to actual opex for non-recurrent expenditure and actual opex on the basis that:

- the ESCV did not explicitly allow for these adjustments in its ECM to apply to the Victorian DNSPs for the 2011–15 regulatory control period
- the Victorian DNSPs did not raise the issue of uncontrollable costs in the ECM in the 2006 EDPR and have previously criticised any attempts to distinguish between management induced efficiencies and windfall gains
- any adjustment for windfall losses would require a consideration of windfall gains (however, given the information asymmetry, the DNSPs may not identify windfall gains).[143]

The AER in the draft decision also did not exclude the impact of non recurrent expenditure (where this does not occur in the base year) on the basis that the ECM is designed to reward the Victorian DNSPs for efficiencies that are sustainable.[144] The AER noted and agrees with the ESCV that where a DNSP incurs substantial one off expenditure increase in any year (other than in the base year), this negative carryover amount would be offset by a positive carryover amount associated with the relative efficiency improvement when opex returns to normal levels in the following year.[145]

In summary, the AER decided not to apply negative a carryover amounts, where this negative carryover amount arose due to the occurrence of a *non-recurrent cost* in the base year.[146] The AER made this decision to use its discretion not to apply a negative carryover amount in these circumstances on the basis that the inclusion of non-recurrent costs that occur in the base year in determining the carryover amounts may reduce the Victorian DNSPs' incentives to reveal their efficient costs over the forthcoming regulatory control period, contrary to clause 6.5.8(c) of the NER.[147] In particular, the AER removed the impact of non-recurrent costs in 2009 associated with and an ATO audit ($0.6m) for CitiPower, costs related to superannuation and an

[143] AER, *Vic Draft Decision,* June 2010, p. 594.
[144] ibid., p. 593.
[145] ESCV, *EDPR 2006–10,* Volume 1, October 2006, p. 424.
[146] ibid., p. 435.
[147] AER, *Vic Draft Decision*, June 2010, p. 594.

ATO audit ($7.3m) for Powercor and costs related to superannuation and bushfire related operating costs of $16.9m for SP AusNet.[148]

13.5.6.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor CitiPower agreed with the AER's draft decision to exclude non-recurrent expenditure from the ECM calculation where this expenditure occurred in the base year (2009). In addition CitiPower and Powercor stated that it should apply to all uncontrollable non-recurrent expenditure that was incurred in 2006–09.[149] CitiPower and Powercor stated that the AER's adjustment only addresses expenditure in 2009 and does not address non-recurrent and uncontrollable expenditure in relation to superannuation and GSL payments in the 2006–08 period.[150]

CitiPower and Powercor submitted that whether the ESCV explicitly allowed for these adjustments in the ECM is not determinative of whether the AER should make these adjustments in the final distribution determination. CitiPower and Powercor also stated the AER's draft determination on these adjustments does not refer to the NEO or revenue and pricing principles or consider whether its decision is consistent with those matters and the AER cannot ignore those matters and simply base its decision on whether the ESCV referred to a matter in the ESCV's 2006 EDPR.[151]

CitiPower and Powercor submitted that the AER's draft decision to reject adjustments to the ESCV benchmark allowances for uncontrollable costs is incorrect, based in part on errors of law, inconsistency with the NEL and NER and inconsistency with the AER's decisions and reasons in other parts of the Draft Determination.[152]

CitiPower and Powercor submitted that the ESCV adopted a general principle that adjustments must be made so that actual opex can be compared with the ESCV benchmark opex allowances on a 'like for like' basis. In this regard, the proposed adjustments to the ESCV's benchmark allowances are allowed for and are consistent with the ESCV's ECM.[153]CitiPower and Powercor further submitted that the AER is required accept the adjustments to actual opex for identified uncontrollable costs to ensure that the ESCV benchmark and actual expenditure is compared on a 'like for like' basis. CitiPower and Powercor provided the following reasons in support of this view:

- the approach taken in the ESCV's 2006 EDPR to enable a 'like-for-like comparison between the ex post opex benchmarks and actual opex
- the ORG Appeal Panel Decision in relation to the ORG's 2001 EDPR, which required ex post adjustments in calculating the carryover amounts arising from the previous regulatory period so that the benchmarks and actual opex expenditure were comparable and an accurate measure of efficiency

148 AER, *Vic Draft Decision*, June 2010, p.597
149 CitiPower, *Revised regulatory proposal*, p. 385; Powercor, *Revised regulatory proposal*, p. 385.
150 ibid.
151 CitiPower, *Revised regulatory proposal*, p. 377; Powercor, *Revised regulatory proposal*, p. 372.
152 CitiPower, *Revised regulatory proposal*, p. 375; Powercor, *Revised regulatory proposal*, p. 371.
153 CitiPower, *Revised regulatory proposal*, p. 376; Powercor, *Revised regulatory proposal*, p. 371.

- the AER's EBSS Guideline, which provides for adjustments for uncontrollable costs and pass through events
- the NEO and the revenue and pricing principles.[154]

CitiPower and Powercor also submitted that it is unreasonable and incorrect for the AER to fail to apply the 'like for like' principle to CitiPower and Powercor's proposed adjustments and to reject those adjustments because they were not explicitly provided for by the ESCV. It is further stated that this is particularly so when AER has accepted the principle and applied it to justify its own adjustments, including adjustments it acknowledges were not provided for by the ESCV.[155]

CitiPower and Powercor also argued that:

- the proposed adjustments to uncontrollable do not involve revisiting the design of the ESCV's ECM
- ex post adjustments to the ECM for uncontrollable and non recurrent costs does not involve retrospective application of the NER to the ESCV's ECM
- the AER cannot reject the proposed adjustments without expressly considering the NEO and revenue and pricing principles simply because the ESCV took a particular view based on different albeit perhaps 'similar' requirements
- there is an inconsistency between the AER's rejection of these adjustments and the AER's decision to make its own adjustments to the ESCV benchmark allowance.[156]

SP AusNet also submitted that its carryover calculation in the final decision should be updated to reflect SP AusNet's most up to date information on its non recurrent opex in the base year (2009), which should be deducted from 2009 actual costs to determine the efficiency carryover amount.[157]

Powercor's vegetation management costs

Powercor submitted that it incurred additional expenditure in 2008 and 2009 in relation to vegetation management that was caused by an uncontrollable change in the scale and scope of its activities. [158] Powercor contended that the AER is required to adjust Powercor's opex to exclude those costs when calculating the 2006–10 carryover amounts because this expenditure was not included in the ESCV's 2006–10 expenditure benchmarks.[159]

Powercor contended that the proposed adjustment is consistent with:

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[154] CitiPower, *Revised* r*egulatory proposal*, pp. 375–76; Powercor, *Revised regulatory proposal*, p. 371.
[155] CitiPower, *Revised regulatory proposal*, p. 384; Powercor, *Revised regulatory proposal*, pp. 379–380.
[156] CitiPower, *Revised* r*egulatory proposal*, pp. 372–84; Powercor, *Revised regulatory proposal*, pp. 367–84.
[157] SP AusNet, *Revised regulatory proposal*, p. 290.
[158] Powercor, *Revised regulatory proposal*, p. 380.
[159] ibid.

- the ORG Appeal Panel Decision

- the ESCV's 'like for like' principle

- Powercor's resultant legitimate expectation, at the time of incurring the additional vegetation management expenditure in 2008 and 2009, that any adjustments required by the 'like for like' principle would be made at the end of the 2006–10 regulatory period

- the AER's acceptance and application of the 'like for like' principle in section 13.5.4 of the draft determination

- the NEO and revenue and pricing principles, including providing DNSPs with effective incentives in order to promote economic efficiency and the efficient provision of electricity network services

- the EBSS principles set out in clause 6.5.8 of the Rules, including providing for a fair sharing of efficiency gains/losses and providing DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex.[160]

13.5.6.3 Issues and AER considerations

AER's Application of the ECM

The AER does not agree with CitiPower and Powercor that whether the ESCV explicitly allowed for adjustments related to uncontrollable costs and non recurrent costs in the ECM is not determinative of whether the AER should make these adjustments in the final decision. As previously stated the Electricity DNSPs' EBSS final decision, requires the AER to implement jurisdictional schemes, in this case the ECM for the Victorian DNSP's.[161] That said, the AER acknowledges that where a negative carryover amount arises it has some discretion as to whether to apply this negative carryover amount (refer to section 'Future treatment of efficiency losses' in the 2006 EDPR).[162] Both CitiPower and Powercor have a negative carryover amount arising from the 2006–10 regulatory period. In applying this discretion made available to the AER under the ECM, the AER notes that it must consider the NEO and the revenue and pricing principles.[163] The AER in exercising its discretion has considered both CitiPower and Powercor's proposed adjustments to their respective carryover amounts against the NEO and the revenue and pricing principles. The AER considerations are detailed below.

In response to CitiPower and Powercor's view that the ESCV adopted a general 'like for like' principle the AER agrees with the ESCV's statement that for the rewards implicit in the ECM to reflect the cost of providing the distribution services, it is important that the reported expenditure information is calculated on the same basis as

160 Powercor, *Revised regulatory proposal*, 21 July 2010, pp. 380–84.
161 AER, *Final decision, Electricity DNSPs' EBSS,* June 2008, p. 13.
162 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 435.
163 It follows that the AER agrees with CitiPower and Powercor that the AER is required to apply the NER to ESCV's ECM.

the expenditure forecasts against which it is compared (referred to as the 'like for like' principle).[164] The AER also notes that in ESCV commented that

> This highlights the importance of clearly establishing the basis for the estimated expenditure for the 2006-10 regulatory period. It is also consistent with the Commission requiring adequate disclosure so that adjustments can be made to compare information on a ‘like for like’ basis over time, across businesses and with benchmarks.[165]

The AER noted in the draft decision that the ESCV identified a number of adjustments that it considered necessary to ensure a 'like for like' comparison between the benchmark allowance and actual opex. The AER noted that these adjustments were limited to:

- growth adjustments
- capitalisation of overheads and
- movements in provisions (that is, non cash items). [166]

The AER also noted that the ESCV excluded related party margins (referred to as contractual arrangements) from the Victorian DNSPs' forecast opex allowance. The AER has, therefore excluded related party margins in determining the Victorian DNSPs carryover amounts to maintain a 'like for like' comparison between the ESCV benchmark allowance and actual opex. This adjustment has been accepted by the Victorian DNSPs (refer to section 13.5.5). The AER considers that the adjustments made in the draft decision are consistent with past ORG/ESCV (and intended ESCV practice in relation to related party margins given that the ESCV excluded related party margins from the Victorian DNSPs benchmark allowances for 2006–10).[167] It follows that the AER does not consider that it has been inconsistent in applying these adjustments by not accepting CitiPower and Powercor's proposed adjustments. That said the AER also, for the reasons discussed below, does not consider that CitiPower and Powercor have demonstrated that these adjustments are consistent with the 'like for like' principle.

The AER in the draft decision reviewed the Appeal Panel Decision for the 2001–05 EDPR and maintains that the Appeal Panel rejected the ORG's 2000 decision not to make provision for ex post adjustments to Powercor's benchmark allowances for the 1995–99 period associated with network growth.[168] As discussed above the AER has adjusted CitiPower and Powercor's ESCV benchmark allowances for network growth (refer to section 13.5.4.).

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164 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 435.

165 ibid., p. 164.

166 ibid., pp. 167–68. The AER notes that the ESCV in its 2006 EDPR also reallocated costs between services during the regulatory control period.

167 The AER in the draft decision also adjusted the Victorian DNSP's actual opex for licence fees and the movement in provisions given that these costs were not reflected in the ESCV benchmark allowance. The AER notes that in applying the ECM to the 2006-10 regulatory control period, the ESCV also excluded these costs from 2001–05 actual opex. Further, the ESCV indicated that it would adjust the benchmark allowance for any changes in a DNSPs capitalisation policy for the purposes of calculating efficiency carryover amounts.

168 AER, *Victorian Draft Decision*, June 2010, p. 592.

In response to CitiPower and Powercor's view that an adjustment to the ECM is consistent with the AER's EBSS Guideline, the AER states in its EBSS Final Decision[169] that the AER will permit a DNSP to propose a range of additional cost categories (this includes uncontrollable costs) and pass through events for exclusion from the operation of the EBSS which are:

- specific to a DNSP, and
- do not involve an ongoing business activity.[170]

However, a DNSP must propose cost categories for exclusion from the EBSS in their regulatory proposal prior to the commencement of the regulatory control period during which the EBSS will be applied. That is, the AER will not accept ex post adjustments to either the benchmark allowance or actual expenditure to account for cost categories that have not been identified ex ante in the EBSS. The AER also notes CitiPower and Powercor commented that the ESCV never sought to define adjustments upfront and always allowed adjustments at the end of the regulatory period on the basis of the 'like for like' principle. The AER notes that the ESCV indicated upfront as part of the 2006 EDPR that ex post adjustments would be made to account for network growth and for any changes in the DNSP's capitalisation policies over the regulatory period to ensure a 'like for like' comparison between the benchmark allowances and actual opex. [171]

The AER also noted in the draft decision that the ESCV discussed the impact of non recurrent expenditure on the ECM. [172] In particular, the ESCV also noted under the ECM a substantial one off (non recurrent) expenditure increase in any year would be offset by the positive carryover associated with the relative efficiency improvement when expenditure returns to normal levels in the following year.[173] The AER notes that under the ECM the impact of non recurrent costs will also be offset when expenditure returns to normal levels in the following year. This treatment of non recurrent costs is also the same as for the AER's EBSS. As a result, the Victorian DNSP's will only be exposed to a one off penalty arising from an unsustainable inefficiency where a non recurrent cost is incurred under both the ECM and EBSS.

In relation to uncontrollable costs as noted in the draft decision, the treatment of uncontrollable costs were not identified in the 2006 EDPR as a relevant consideration for determining the carryover amounts for 2011–15.[174] The AER also notes, as stated in the draft decision, that the ESCV's predecessor, the ORG, previously recognised that the efficiency carryover amounts may include both management induced efficiencies and windfall gains and losses. However, the ORG concluded that given the difficulties of separately identifying management (in) efficiencies from windfall gains and losses, no attempt was made to distinguish the two.[175] Most importantly, the AER noted that the DNSPs’ carryover calculation may have included some 'efficiency

169 AER, *Final Decision Electricity DNSPs EBSS*, June 2008, appendix E, p. 6.
170 ibid.
171 ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 419–21.
172 AER, *Victorian Draft Decision*, June 2010, pp. 593–94.
173 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 435.
174 AER, *Victorian Draft Decision*, June 2010, p. 592.
175 ibid., p. 577.

gains' that may not have been the result of management effort.[176] It was in this sense that the AER considered that CitiPower and Powercor were revisiting the design of the ESCV's ECM. That said the AER has considered CitiPower and Powercor proposed adjustments for uncontrollable costs on the basis that the AER has discretion to apply the negative carryover amount based on the circumstances that have given rise to those amounts, the AER has taken into account into the NEO and revenue and pricing principles of the NEL.

The AER's consideration of the specific adjustments proposed by CitiPower and Powercor are detailed below.

AER's consideration of CitiPower and Powercor's proposed adjustments to the ECM

Superannuation and GSL payments

CitiPower and Powercor in their initial and revised proposals have sought an adjustment to the ESCV benchmark allowance for superannuation costs and GSL payments.[177] The AER notes that the Victorian DNSPs will be exposed to uncontrollable costs associated with defined benefits scheme employees. This category of cost has been excluded from the AER's EBSS. These costs have been excluded from the EBSS because these costs are uncontrollable given that defined benefit scheme liabilities are affected by stock market volatility.

The AER notes that the ESCV had regard to CitiPower and Powercor's actual costs based on the 2004 regulatory accounts in establishing CitiPower and Powercor' benchmark allowances. Accordingly, to assess whether actual opex is being compared 'like for like' with the ESCV benchmark allowance requires information on the basis on which the ESCV benchmark was established. The AER notes that the ESCV had regard to actual opex in 2004 (that is, the base year for determining the 2006–10 benchmark allowances). The AER therefore expects that superannuation costs would be reflected in the ESCV benchmark allowances for 2006–10. CitiPower and Powercor have not demonstrated that actual superannuation payments (only related to defined benefit scheme employees) incurred over the 2006–10 period are not comparable to the ESCV benchmark allowances. Accordingly, the AER cannot be satisfied that any adjustment would be consistent with providing a 'like for like' comparison of the ESCV benchmark allowance and actual expenditure. In contrast, the AER notes that under its EBBS, defined benefit scheme costs have been separately identified which will allow the AER to undertake an ex-post adjustment in determining CitiPower and Powercor's carryover amounts under the EBSS for 2016–20.

In relation to GSL payments, CitiPower and Powercor have proposed adjustments based on climate change.[178] The AER notes that CitiPower and Powercor have not provided evidence to substantiate this view that directly links GSL payments to the affects of climate change. As noted elsewhere in this final decision the AER expects that the impact of climate change is likely to be gradual such that the impact of climate change on the DNSPs costs will be progressive over time. Accordingly, the

[176] AER, *Victorian Draft Decision*, June 2010, p. 577.
[177] CitiPower, *Revised regulatory proposal*, July 2010, p. 371; Powercor, *Revised regulatory proposal*, July 2010, p. 362.
[178] CitiPower, *Regulatory proposal*, p. 253; Powercor, *Regulatory proposal*, p. 258.

AER does not consider this adjustment is consistent with maintaining a 'like for like' comparison between the ESCV benchmark allowance and actual opex.

JEN also adjusted actual opex to exclude GSL payments in its supporting EBSS model. The AER as discussed above notes that GSL payments are already included in the ESCV benchmark allowance. Accordingly, the AER has not accepted this adjustment consistent with the 'like for like' principle.

ESCV base year adjustment and efficiency factor adjustment
Powercor also argued that the ESCV's efficiency adjustment to the base year of $5.5m ($2004) in establishing its 2006–10 benchmark allowances for 2006–10 should be removed in calculating the efficiency carryover amounts. CitiPower and Powercor also argued that the ESCV's economy wide efficiency factor of 0.39 per cent per annum used to establish the ESCV benchmark allowances for 2006–10 should be removed from the efficiency carryover calculation. CitiPower and Powercor argued that their proposed adjustments to remove the 'base year efficiency adjustment' (Powercor only) and the efficiency factor is necessary so that the efficiency calculation is consistent with the principles set out in the AER's EBSS and with the clause 6.5.8(c) of the NER and 7A(3) of the NEL.

The AER as previously discussed has applied the ECM in accordance with the EBSS final decision and as previously discussed, the EBSS final decision was developed and published under clause 6.5.8(c) of the NER. Moreover as previously discussed the AER accepted submissions from Powercor, along with CitiPower, seeking clarification from the AER that the AER would use jurisdictional arrangements to calculate carryovers for the DNSPs currently operating under jurisdictional efficiency carryover schemes, and had regard to those submissions in making its decision.[179] That said the AER does not agree with CitiPower and Powercor that the ESCV application of a downwards adjustment of $5.5m to establishing Powercor's base year opex and the application of the ESCV's forecast partial productivity improvement of -0.39 per cent per annum is inconsistent with the AER's EBSS. In finalising the EBSS the AER stated that:

> The AER considers that it is not appropriate, when determining the efficiency opex allowance for future regulatory control periods, to relate future targets to past outcomes on a purely mechanistic basis. That is, the AER will not require forecast opex for the following regulatory control period to be equal to actual opex in a single year of the current regulatory control period during which the EBSS is applied. In this EBSS a single regulatory year in the current regulatory control period used as a basis for the forecasts in the following regulatory control period is referred to as the base year.[180]

The AER also notes that in assessing a DNSP's opex forecast it must address the matter set out in clause 6.5.6 of the NER. In particular, the AER noted that in assessing a DNSP's opex forecast that while it would place significant weight on the actual opex in the base year, the AER must have regard to the operating expenditure criteria and factors as set out in clause 6.5.6 of the NER.[181] Accordingly, the AER

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179 AER, *EBSS Final decision*, June 2008, p. 12.
180 AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008, p. 4.
181 ibid., p. 4.

does not agree with Powercor that the ESCV's approach to establishing its base year level of opex in the 2006 EDPR is inconsistent with the EBSS and the 6.5.8(c) of the NER. It follows that this approach is also not inconsistent with the 7A(3) of the NEL.

The AER also considers that the ESCV’s efficiency factor of 0.39 per cent per annum would not dampen the Victorian DNSPs incentives to continuously seek cost reductions over the regulatory period from in accordance with objectives of clause 6.5.8 of the NER. The ESCV’s 0.39 per cent efficiency factor represented an economy wide efficiency factor such that the DNSPs would be rewarded where their actual costs are lower than the efficiencies available across all businesses in the economy, which is consistent with objectives of 6.5.8 of the NER to provide the Victorian DNSPs incentives to continuously seek cost reductions. To the extent that the Victorian DNSP's have achieved greater efficiencies than assumed by the ESCV, the DNSP will retain these efficiencies for a period of five years under the ECM. Accordingly, the ESCV's partial productivity factor is consistent with providing incentives for the DNSP to pursue efficiencies consistent with the objectives of the EBSS under clause 6.5.8(c) of the NER and with providing effective incentives to operate the network efficiently in accordance with section 7A(3) of the NEL.

Powercor's vegetation management costs

Powercor also proposes to exclude vegetation management costs incurred in 2008 and 2009 on the basis that these costs reflected an uncontrollable change in the scope of Powercor’s activities. In particular, Powercor argued that it has incurred more costs than was assumed in the ESCV's benchmark allowance. Powercor stated that these costs have been incurred on the expectation that an exemption from its obligations under these regulations that was issued by the ESCV was expected to expire.[182]

In considering this issue the AER notes that this expenditure is not non-recurrent expenditure as CitiPower and Powercor has sought increased opex in the forthcoming regulatory control period (the AER' assessment of this opex is discussed in chapter 7). The AER has accepted that non-recurrent expenditure in the base year should be excluded from the efficiency carryover calculation (refer to section 13.5.6.4). The AER notes in this circumstance the additional costs incurred by Powercor are reflected in its base year cost such that the AER's concerns regarding the incentives to pursue efficiencies does not arise in relation to Powercor's vegetation management costs.

The AER notes that Powercor considers this expenditure to be an uncontrollable cost associated with a change in the scope of its activities. The AER further notes that CitiPower and Powercor have provided evidence that these additional costs were not included in the ESCV benchmark allowance.[183] While the AER accepts that these additional cost have not been included in the ESCV benchmark allowance, the AER does not consider that an adjustment to remove these costs from actual opex in the efficiency carryover calculation is consistent with the ORG's Appeal Panel Decision nor the ESCV's 'like for like principle'. As discussed above, the ORG Appeal Panel decision considered that an adjustment should be made for network growth to ensure a

182 The AER notes this exemption was in place until June 2010 which corresponds to the sunset date for the 2005 Line Clearance Regulations.

183 ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 223–24; Powercor, *Revised regulatory proposal, attachment 243*.

'like for like' comparison between the benchmark allowances and actual opex. In respect of the ESCV's approach to ensuring a 'like for like' comparison, as discussed previously the AER has applied the adjustments to the Victorian DNSPs:

- consistent with past ORG/ESCV practice
- the ORG considered that it was not appropriate to adjust the ECM for uncontrollable costs and this issues was not identified by the ESCV in its 2006 EDPR
- the decision by the AER not to make this adjustment is not inconsistent with its approach to apply adjustments elsewhere and with the ORG/ESCV's past practice.

The AER notes that while there may be sound business reasons for Powercor to have incurred these costs, the AER does not consider that an adjustment to remove the costs incurred by Powercor in 2008 and 2009 for vegetation management costs is consistent with the 'like for like' principle. That is the AER notes that Powercor has incurred costs in anticipation that its exemption would cease after the expiry of this exemption in June 2010. However, the AER notes that the ESV advised the Victorian DNSPs that this exemption would expire on 13 October 2009.[184] Accordingly, the AER notes that Powercor has made a business decision independent of its legislative obligations to incur additional expenditure in 2008 and 2009. The AER therefore does not consider it appropriate for Powercor's efficiency carryover amounts to be adjusted for this additional expenditure in 2008 and 2009. The AER has, however, included these costs in Powercor's forecast opex for the forthcoming regulatory control period. This means that Powercor will incur a negative efficiency amount but this will be will be offset by a higher forecast allowance over the 2006–10 regulatory control period.

The AER does not consider that Powercor's proposed adjustment is consistent with the NEO and 7A (2)(3) of the NEL as contended by Powercor. The AER considers that Powercor should share the efficiency losses of this additional expenditure with customers on the basis that Powercor has incurred additional costs over the regulatory period, Specifically, the AER does not accept that Powercor has incurred additional costs related to meeting any legislative requirements in the 2006–10 regulatory period and therefore some of these efficiency losses should be borne by Powercor before these additional costs are passed back to customers. This maintains a symmetrical treatment to efficiencies under the ECM by recognising both efficiency gains and losses which the AER regards as being consistent with the NEO section 7(A)(3) of the NEL and 6.5.8(c) of the NER for the reasons outlined in section 13.5.3.3.

The AER also notes that the principle in section 7A (2) of the NEL requires the DNSPs to be provided with a reasonable opportunity to recover efficient costs. Because Powercor will be compensated for the costs it incurred in the base year (2009) as these cost are reflected in Powercor' opex forecast for the 2011–15 regulatory control period, Powercor will not be denied a reasonable opportunity to recover its efficient costs by including Powercor's vegetation cost in the calculation of efficiency carryover amounts.

184 ESV letter to Powercor, Electricity Safety (Electric Line Clearance) Regulations, exemptions associated with the Code of Practice, 7 December 2009. Note the 2009 Regulations have now been replaced with the 2010 Line Clearance Regulations.

In conclusion, the AER, in calculating the efficiency carryover amounts from the ESCV's ECM, has not adjusted the benchmark allowance for uncontrollable costs for CitiPower and Powercor.

Treatment of non-recurrent costs in the base year

The AER maintains its draft decision that where a non-recurrent cost is incurred in the base year, the AER has decided to override the ESCV's presumption to apply negative carryovers by not applying the negative carryover amounts associated with non recurrent costs that are incurred in the base year. The AER considers this will remove the efficiency loss to be carried forward for five years thereby resulting in the loss of incentives for DNSPs to reveal their efficient level of costs over the forthcoming regulatory control period contrary to clause 6.5.8(c) of the NER. [185] Accordingly, the AER has applied the updated efficiency carryover amounts for the non-recurrent costs provided by SP AusNet that occurred in the base year.

13.5.6.4 AER conclusion

The AER, in calculating the efficiency carryover amounts from the ESCV's ECM, has not adjusted the benchmark allowance for uncontrollable costs incurred in 2006–09 and non recurrent costs incurred in 2006–08 on the basis that:

- the AER does not consider that Powercor and CitiPower's uncontrollable costs and non recurrent costs will maintain a 'like for like' comparison between the ESCV benchmark allowance and actual opex

- CitiPower and Powercor's proposed adjustments for the ESCV's $5.5m efficiency factor (Powercor only) and partial productivity factor of 0.39 per cent per annum used to establish CitiPower and Powercor's opex forecast is consistent with the NEL and the NER (including 6.5.8(c)) of the NER for the reasons explained in this decision. The Victorian DNSPs did not raise the issue of uncontrollable costs in the ECM in the 2006 EDPR and have previously criticised any attempts to distinguish between management induced efficiencies and windfall gains

- The AER also does not consider that Powercor's proposed exclusion of vegetation management costs is appropriate given that this represents additional opex incurred that was not the result of an external obligation requiring a change in scopes of its business activities, and noting that the inclusion of these costs in the base year establishes a higher base for forecast opex.

The AER has decided not to apply the presumption in the ECM to apply negative carryover amounts [186] where this negative carryover amount arises due to the occurrence of a non-recurrent cost in the base year on the basis that the inclusion of non-recurrent costs in determining the carryover amounts may reduce the Victorian DNSPs' incentives to reveal their efficient costs over the forthcoming regulatory control period, contrary to clause 6.5.8(c) of the NER.

The AER's adjustments to the Victorian DNSPs' 2006–10 benchmark allowances and their reported expenditure for the purposes of calculating the carryover amounts for

[185] AER, *Victorian Draft Decision*, June 2010, pp. 593–94.
[186] ibid., p. 435.

the forthcoming regulatory control period are outlined in table 13.4 and table 13.5 respectively.

Table 13.4 AER conclusion on adjustments to 2006–10 opex benchmark ($’m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Original benchmark opex	40.4	41.7	41.8	42.7	43.5
Capitalisation policy	0.0	0.0	0.0	0.0	0.0
Growth adjustment	–0.2	–0.5	–0.7	–0.9	–1.1
Revised benchmark opex	40.1	41.2	41.2	41.8	42.4
Powercor					
Original benchmark opex	135.3	138.4	141.0	144.1	147.8
Capitalisation policy	0.0	0.0	0.0	0.0	0.0
Growth adjustment	0.6	1.2	1.8	2.5	3.1
Revised benchmark opex	135.9	139.6	142.9	146.6	150.9
JEN					
Original benchmark opex	59.4	60.4	61.6	62.9	64.4
Capitalisation policy	0.0	0.0	4.6	4.6	4.6
Growth adjustment	0.1	0.2	0.3	0.4	0.5
Revised benchmark opex	59.5	60.6	66.5	67.9	69.5
SP AusNet					
Original benchmark opex	126.6	129.8	133.2	136.6	140.3
Capitalisation policy	0.0	0.0	0.0	0.0	0.0
Growth adjustment	–0.2	–0.4	–0.5	–0.7	–0.9
Revised benchmark opex	126.4	129.4	132.7	135.9	139.4

Source: AER analysis.

Table 13.5 AER conclusion on adjustments to 2006–10 reported opex ($’m, 2010)

	2006	2007	2008	2009
CitiPower				
Reported opex	[c-i-c]	34.9	33.7	36.6
Provisions	0.1	–2.1	–1.4	1.0
AMI adjustment	0.7	–1.1	–	–
Licence fees	–0.8	–0.6	–0.5	–0.2
Related party margins	[c-i-c]	–	–	–
Non-recurrent expenditure	–	–	–	–
Revised opex	27.8	31.1	31.8	37.4
Powercor				
Reported opex	[c-i-c]	113.7	119.3	126.6
Provisions	2.0	0.8	–6.2	4.9
AMI adjustment	0.7	–1.2	–	–
Licence fees	–1.7	–0.8	–0.8	–0.3
Related party margins	[c-i-c]	–	–	–
Non-recurrent expenditure	–	–	–	–2.0
Revised opex	129.5	112.6	112.4	129.2
JEN				
Reported opex	54.4	57.4	48.3	51.1
Provisions	–0.2	–0.1	0.4	–0.2
Licence fees	–0.8	0.0	–0.4	0.1
ACS adjustment	–	–	–	0.2
SP management fee	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Corporate strategy costs	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Related party margins	–	–	–	–
Non-recurrent expenditure	–	–	–	[c-i-c][a]
Revised opex	53.5	56.3	46.0	48.1

SP AusNet				
Reported opex	92.9	113.2	124.8	141.0
Provisions	–0.7	–2.5	–0.8	1.0
Licence fees	–0.6	–1.0	–0.6	–0.3
Related party margins	–	–	–	–
Non-recurrent expenditure	–	–	–	–16.9
Revised opex	91.7	109.7	123.4	124.8

Source: AER analysis.
[a]:JEN's positive provision write-back adjustment.

13.6 AER conclusion

The Victorian DNSPs' revised carryover amounts are detailed in table 13.2. The AER notes that this is a decision in relation to other inputs, values and amounts in the building block model, in accordance with clause 6.12.1(9)(10) of the NER. The AER has reviewed the Victorian DNSPs' revised ECM and has not applied the ECM to United Energy (as noted in section 13.5.1). The AER has also made adjustments to the Victorian DNSPs' proposed carryover amounts in relation to:

- inclusion of the accrued negative carryover amounts arising from the 2001–05 regulatory period (Powercor only as noted in section 13.5.2)
- no application of NPV approach to CitiPower, where CitiPower will receive a net negative carryover amount (given that CitiPower's efficiency losses outweighed efficiency gains arising in the 2006–10 regulatory period) (as noted in section 13.5.3)
- ex post adjustments to the benchmark allowance associated with network growth (as noted in section 13.5.4)
- adjustments to the benchmark allowance and actual expenditure to ensure comparability between the benchmark allowance and actual expenditure (as noted in section 13.5.5)
- other adjustments (as noted in section 13.5.5)
- non-recurrent costs that occur in the base year (as noted in section 13.5.6).

In accordance with clauses 6.4.3(a)(6) and 6.12.1(9)(10) of the NER, and the AER's EBSS for this final decision, the AER has applied the ECM for Victorian DNSPs as set out in table 13.6. This value is used as an input to the Post Tax Revenue Model (PTRM) for the purposes of determining the Victorian DNSPs' annual building block revenue requirement during the 2011–15 regulatory control period.

Table 13.6 AER conclusion on the Victorian DNSPs' carryover amounts 2011–15 ($’m, 2010)

	2011	2012	2013	2014	Total
CitiPower	4.4	–8.0	–5.7	–4.9	**–14.3**
Powercor	0.0	1.2	–9.7	–13.1	**–21.7**
JEN	19.9	13.9	15.6	–0.6	**48.7**
SP AusNet	11.1	–23.6	–8.6	1.8	**–19.4**

Source: AER analysis.

14 Efficiency benefit sharing scheme

This chapter sets out the AER's final decision on application of the efficiency benefit sharing scheme (EBSS) to the Victorian DNSPs during the forthcoming regulatory control period.

The EBSS is a key feature of the regulatory regime applying to standard control services. Any gains or losses achieved by a DNSP as a result of actual opex diverging from forecast benchmark opex in one regulatory period are shared with customers in the following regulatory period.[1]

The AER published the *Electricity distribution network service providers, Efficiency benefit sharing scheme* (national distribution EBSS) in June 2008.[2] In its Framework and approach paper for the Victorian distribution determination, the AER stated that its likely approach would be to apply the national distribution EBSS in Victoria during 2011–15.[3]

Under the scheme, efficiency gains (losses) achieved by Victorian DNSPs during 2011–15 will be carried over as an addition to (subtraction from) their revenue requirement established for the 2016–20 regulatory control period.

14.1 Regulatory requirements

Clause 6.3.2(a)(3) of the NER requires that a building block determination is to specify for a regulatory control period how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme are to apply to the DNSP.

Clause 6.4.3(a)(5) states that the annual revenue requirement for a DNSP for each regulatory year of a regulatory control period must be determined using the building blocks, which include the revenue increment or decrements that may arise as a result of the operation of the applicable EBSS.

As set out above the applicable EBSS is the national distribution EBSS published by the AER in June 2008. The AER developed and published this scheme in accordance with clause 6.5.8(a) of the NER, which requires the AER to establish a scheme that shares between DNSPs and network users the efficiency benefits or efficiency losses that result from a DNSP's actual opex diverging from its forecast opex for a regulatory control period.

In developing and implementing an EBSS, clause 6.5.8(c) requires the AER to have regard to:

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1 As an input into derivation of the building block determination, the EBSS only applies to standard control services opex.

2 AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008. (Available at: http://www.aer.gov.au/content/index.phtml/itemId/720374)

3 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, regulatory control period commencing 1 January 2011*, May 2009, pp. 112–113.

(1) the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers; and

(2) the need to provide Distribution Network Service Providers with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure and, if the scheme extends to capital expenditure, capital expenditure; and

(3) the desirability of both rewarding Distribution Network Service Providers for efficiency gains and penalising Distribution Network Service Providers for efficiency losses; and

(4) any incentives that Distribution Network Service Providers may have to capitalise expenditure; and

(5) the possible effects of the scheme on incentives for the implementation of non-network alternatives.

In accordance with these regulatory requirements, the AER published a national EBSS that will apply to the Victorian DNSPs from 1 January 2011 to 31 December 2015.[4]

14.2 AER draft decision

The AER's draft decision:

- applied the national distribution EBSS in Victoria for the forthcoming regulatory control period
- established that where the Victorian DNSPs changed their capitalisation policies during 2011–15, the AER would adjust their forecast and actual opex when calculating carryover amounts to apply in 2016–20, to ensure integrity of the EBSS
- included a growth adjustment to ensure DNSPs were not penalised or rewarded for changes in the actual level of network growth beyond their control. This would ensure that the AER could compare forecast and actual opex on a like-for-like basis thereby providing a more accurate measure of efficiencies achieved by a DNSP.

The AER noted the growth adjustment to be applied should be consistent with the method adopted by the AER to escalate opex for forecast network growth, which was set out in appendix J of the draft decision.

Consequently, to calculate EBSS carryover amounts, the draft decision determined that the Victorian DNSPs' forecast opex will be adjusted for:

- the actual growth in line length

4 AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008.

- the number of distribution transformers and zone substation capacity
- customer numbers experienced over the forthcoming regulatory control period.

The draft decision considered that superannuation costs for defined benefits and retirement schemes should be excluded from calculation of EBSS carryover amounts, on the basis that they were outside DNSPs' control.[5]

To provide the Victorian DNSPs with a continuous incentive to reduce opex as required by clause 6.5.8(c)(2) of the NER, the AER's draft decision determined to also exclude the following expenditure categories from calculation of EBSS carryover amounts during 2011–15:

- equity raising costs–these are not part of the Victorian DNSPs' opex allowance and instead are recovered through the regulatory asset base[6]
- self insurance costs–these are based on independent expert analysis and not historical costs in the base year and therefore do not directly influence future opex forecasts[7]
- GSL payments–Victorian DNSPs allowance for GSL payments are forecast based on an average of historic payments, consequently the Victorian DNPSs already have a constant incentive to reduce these GSL payments. This incentive would be distorted if GSL payments were included in the EBSS.[8]

Further, the AER considered that it has encouraged the Victorian DNSPs through the DMIA to incur opex on non-network alternatives and therefore considers these costs should be excluded from the EBSS for the forthcoming regulatory period.[9] This is consistent with application of the EBSS, which requires opex spent on non-network alternatives to be excluded.

All other costs (referred to as 'controllable opex') were considered within the Victorian DNSPs' control and therefore included in the EBSS for the purposes of calculating carryover amounts applicable in 2016–20.

Table 14.1 sets out the AER's draft decision on the Victorian DNSPs' controllable opex forecasts used to calculate efficiency gains and losses for the forthcoming regulatory control period.

The draft decision also set out the EBSS formula to apply during 2011–15 as follows:

5 AER, *Draft decision*, p. 608.
6 ibid.
7 ibid.
8 ibid.
9 Ibid.

First year formula

The EBSS states that the AER will calculate an efficiency gain or loss in the first year of the regulatory control period using the following formula:

$$E_1 = F_1 - A_1$$

where:

E_1 = the efficiency gain/loss in year 1

A_1 = actual opex incurred by the DNSP for year 1 of the regulatory control period

F_1 = forecast opex accepted or substituted by the AER in the distribution determination for year 1 of the regulatory control period.

Subsequent years' formula

Gains or losses that arise in the second and subsequent years of the regulatory control period will be calculated as:

$$E_t = (F_t - A_t) - (F_{t-1} - A_{t-1})$$

where:

E_t = the efficiency gain/loss in year t

A_t, A_{t-1} = the actual, or adjusted actual, opex incurred in years t and t–1 respectively

F_t, F_{t-1} = the forecast, or adjusted forecast, opex accepted or substituted by the AER for years t and t–1 respectively.

The AER will use this formula to calculate efficiency gains for the years 2012 to 2015.

Final year formula

As the distribution determination for the 2016–20 regulatory control period will be made prior to the completion of the forthcoming regulatory control period, the AER will estimate the actual opex required to calculate gains or losses for the final year of the forthcoming regulatory control period (2015), as follows:

$$A_5 = F_5 - (F_4 - A_4)$$

Where differences arise between this estimate and the actual expenditure in the final year, the efficiency gain or loss in the first year of the 2016–20 regulatory control period (E_6) will be adjusted as follows:

$$E_6 = (F_6 - A_6) - (F_5 - A_5) + (F_4 - A_4)$$

Given that the Victorian DNSPs have been operating under an efficiency carryover mechanism that is substantially similar to EBSS, the AER will use this formula to calculate efficiency gains or losses under the EBSS for 2011, rather than the first year formula above.

Table 14.1 AER draft decision, forecast EBSS controllable opex, ($m, 2010).

Distributor	2011	2012	2013	2014	2015	Total
CitiPower	34.88	34.88	35.60	36.94	37.22	**179.53**
Powercor	116.97	118.18	120.31	125.14	126.47	**607.07**
JEN	46.94	47.17	47.59	50.74	50.25	**242.69**
SP AusNet	124.34	125.52	127.89	130.77	132.62	**641.14**
United Energy	89.09	89.62	90.89	93.93	94.40	**457.92**

Source: AER, draft decision, pp. 613-615.

14.3 Victorian DNSP revised regulatory proposals

CitiPower and Powercor did not agree with the AER's rejection of their respective proposals. Their initial proposals requested that pass through events nominated by them but not accepted by the AER should still be treated as excluded cost categories for the purposes of the EBSS. CitiPower and Powercor both argued that the AER's decision to reject this proposal was unreasonable, incorrect and based on errors of fact.[10]

CitiPower's and Powercor's revised proposals submitted a number of additional uncontrollable expenditure categories that they considered should be excluded from calculation of the EBSS. These are outlined in section 14.5.3.

JEN generally concurred with the AER's draft decision proposed EBSS specification for the forthcoming regulatory control period, however considered that the following should be excluded from the scheme:

- new tariff assignment dispute resolution costs
- Energy Safe Victoria fees
- Ombudsman scheme costs
- high voltage (HV) injection claims.[11]

[10] CitiPower, *Revised Regulatory Proposal 2011-15*, July 2010, p. 390; Powercor, *Revised Regulatory Proposal 2011-15*, July 2010, p. 388.
[11] JEN, *Revised Regulatory Proposal*, July 2010, pp. 275-276.

SP AusNet agreed with the AER's draft decision, subject to the AER updating the growth adjustment algorithm for the scale escalator factor that is accepted by the AER in the final decision.[12]

United Energy proposed that:

- the opex efficiency carryover amounts from 2006–2010 should be incorporated into the building block revenue requirement for 2011–2015, without merging the ECM and EBSS
- the first year formula (shown on page 600 of the AER's draft decision) should be used to calculate efficiency gains for 2011, not the final year formula (shown on page 600 of the draft decision)
- there are sound reasons for removing from the EBSS events that qualify as pass-throughs but which do not satisfy the materiality threshold[13]
- the demand growth adjustment should be consistent with that used under the efficiency carryover mechanism developed by the ESCV.[14]

14.4 Submissions

The Energy Users Association of Australia (EUAA) stated that if the AER affirmed its draft decision as the final this would likely provide for the efficient provision of network services in Victoria. It would ensure any efficiency benefits are shared with end users.[15]

EnergyAustralia was concerned that the AER might adjust the base opex by removing non-recurrent costs but fail to also remove them from calculation of EBSS carryover amounts.[16]

No other submissions were received regarding the EBSS.

14.5 Issues and AER considerations

14.5.1 Growth adjustments

A.1.1.1 AER draft decision

The draft decision stated that the calculation of the EBSS would include an adjustment for network growth outside the control of the DNSPs, consistent with the algorithm set out in chapter 14 of the draft decision.

12 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 292.
13 The AER has determined that the materiality threshold is 1 per cent of maximum allowable revenue in any single year
14 United Energy, *Revised Regulatory Proposal 2011-2015*, July 2010, p. 297.
15 EUAA, *Submission to the AER on its Draft Decision on the Revenue and Price Proposals by the Victorian Electricity Distributors for the Period 2011-2015*, August 2010, p. iii.
16 EnergyAustralia, *EnergyAustralia's submission on the AER's draft regulatory determination for Victorian distributors*, August 2010, pp. 8-10.

14.5.1.1 Victorian DNSP revised regulatory proposals

Only SP AusNet and United Energy disputed the growth adjustment algorithm. SP AusNet recommended opex benchmarks did not need to be adjusted because actual lagged line length was a known input and would not change during the forthcoming regulatory control period, therefore actual lagged line length would equal forecast line length.

United Energy proposed that the demand growth adjustment should be consistent with that used under the efficiency carryover mechanism developed by the ESCV.

14.5.1.2 Issues and AER considerations

The integrity of the EBSS and the carryover amounts rely on distributors being given a continuous incentive to reduce opex (required by clause 6.5.8(c)(2) of the NER) and on symmetry between the opex allowances approved by the AER and applied using the methodology in section 2.3.2 of the EBSS.[17]

The AER sets out in appendix J of this final decision how it compensates for growth in the size of the DNSPs' distributions networks.

The AER considers that any ex-post adjustment to forecast opex for the purposes of calculating efficiency carryover amounts should use the same method as used to account for growth in the original opex forecasts where practical. This ensures that the forecast opex amounts used to calculate carryover amounts are the same as those that would have been provided to the Victorian DNSPs in their regulatory allowances had the level of network growth that would occur been known with certainty.

Consistent with the methodology in appendix J, when assessing EBSS carryover amounts to apply in 2016–20, the AER will substitute actual values for customer numbers, the number of distribution transformers, zone substation capacity and line length for the years 2011–14 and a revised forecast for 2015, for the forecasts of these metrics used in this final decision. The approach to calculating the allowance for scale escalation is set out in appendix J of this final decision.

The AER will apply the methodology for adjusting the EBSS over the forthcoming regulatory control period as set out in appendix J of this final decision.

14.5.1.3 AER conclusion

The AER does not accept SP AusNet's positions on the growth adjustment algorithm because they are inconsistent with clause 6.5.8(c)(2) of the NER.

Further the AER does not accept United Energy's proposal to use the demand growth adjustment used under the efficiency carryover mechanism developed by the ESCV. The AER considers that the EBSS should be adjusted for actual network growth using the same method as used to adjust their opex allowance for network growth as set out in appendix J.

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17 AER, *Electricity distribution network service providers efficiency benefit sharing scheme, appendix E*, June 2008, pp.6-7.

In accordance with section 2.3.2 of the EBSS guideline, to calculate EBSS carryover amounts during the forthcoming regulatory control period, the AER will substitute actual values for customer numbers, the number of distribution transformers and zone substation capacity MVA and line length for the years 2011–14 and a revised forecast for 2015, for the forecasts of these metrics used in this final decision.

14.5.2 Cost categories rejected as pass through events

14.5.2.1 AER draft decision

The AER's draft decision included in the calculation of EBSS carryover amounts the costs incurred by the Victorian DNSPs which the AER does not consider to be pass through costs.[18] The costs of recognised pass through events are excluded from the EBSS.

The draft decision concluded that costs associated with the following should be excluded from the calculation of EBSS carryover amounts:

- debt raising
- self insurance
- defined benefits superannuation and retirement schemes
- the DMIA
- GSL payments
- non-network alternatives
- recognised pass through events.

14.5.2.2 Victorian DNSP revised regulatory proposals

All Victorian DNSPs submitted that the AER needed to explicitly identify which cost categories would be pass-through events and therefore excluded from EBSS calculations during 2011–15. The DNSPs considered that this would provide them with certainty regarding cost recovery during the 2011–15 regulatory control period.

Furthermore, the DNSPs advised that events that would qualify as regulatory change events or service standard events as defined in the NER glossary also needed to be specified by the AER in advance.

14.5.2.3 Issues and AER considerations

Chapter 16 of this final decision sets out the pass through framework and nominates the following pass-through categories to apply for the forthcoming regulatory control period. These nominated pass through events are:

- the insurer credit risk event

[18] AER, *Draft decision*, p. 609.

- the natural disaster event
- the insurance cap event
- the (declared) retailer of last resort event.
- the networks charges event.

Costs associated with these events will be excluded from the EBSS.

In addition, events that the AER considers are regulatory change events or service standard events under the pass through framework will be automatically excluded from the EBSS.

As noted in chapter 16, the AER will assess separately the merits of any DNSP's application to pass-through to customers the costs of a regulatory change event or a service standard event. There are several pass through events proposed by the DNSP have not been accepted as nominated pass through events, but which the AER considers will fall within the NER defined pass through events (particularly, a service standard event or a regulatory change event, subject to the materiality threshold in the NER). These are:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework/a transfer of customer regulation to national regulatory framework event
- changes to safety regulations introduced by the ESV/changes to bushfire mitigation framework
- changes to exposure limits
- an emissions trading scheme event/ a CPRS event
- an ESMS event
- an AEMO fees and charges event.[19]

Events which appear to be regulatory change events or service standard events, but do not meet the pass through materiality threshold in the NER will not be excluded from the reported opex when calculating EBSS carryover amounts.

In regard to United Energy's position that events which qualify as pass-throughs but do not satisfy the materiality threshold should be excluded from the EBSS, the AER notes that it has not amended the materiality threshold in the draft decision (set at 1 per cent of maximum allowable revenue). If a pass-through event fails to meet the materiality threshold a DNSP will bear the costs of those events. However, because those costs will be included in the EBSS those costs will be shared between the DNSP and network users according to the sharing ratio. That is, regardless of the nature and

19 This would likely be a tax change event.

timing of the event the cost will be shared approximately 30:70 between the DNSP and network consumers.

If the costs of event are included in the EBSS how those costs are shared between a DNSP and network users will depend on the nature and timing of the event. If a non-recurrent event occurs and the cost of that event was included in the EBSS, the DNSP would incur the entire cost of that event. If the costs of that event are recurrent, how those costs are shared depends on the timing of the event. The earlier in the regulatory control period the event occurs the greater is the proportion of costs borne by the DNSP. That is, the DNSP has to wait longer before the costs are rolled into their base year costs used to forecast opex for the following regulatory control period.

14.5.2.4 AER conclusion

The AER's final decision is to exclude the costs associated with pass- through categories nominated by the AER (as set out in chapter 16 and in section 1.5.2.3) from the calculation of EBSS carryover amounts. If such an event occurs, and is accepted by the AER as a pass-through event, the costs of that event will be excluded from the EBSS.

If a regulatory change event or service standard event occurs but it does not satisfy the materiality threshold, the costs of that event will be included as opex when calculating EBSS carryover amounts. This ensures that the costs of the event are shared between the DNSP and network users according to the sharing ratio in the EBSS.

14.5.3 Additional proposed excluded cost categories

14.5.3.1 AER draft decision

Cost categories that were excluded from the EBSS in the draft decision are set out in section 1.2 of this chapter.

14.5.3.2 Victorian DNSP revised regulatory proposals

CitiPower's and Powercor's revised proposals submitted that the following costs could not be forecast and should be excluded from calculation of carryover amounts under the EBSS:

- costs arising from the transfer of non-price distribution regulatory arrangements to a national regulatory framework
- costs arising from changes to safety regulations introduced by Energy Safe Victoria (ESV)
- costs arising from the financial failure of a retailer event
- costs arising from changes in exposure limits introduced as part the radiation protection standard for exposure limits to magnetic fields 0Hz, by the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA)
- fees or charges payable to the Australian Energy Market Operator (AEMO)

- costs arising from recommendation of the Victorian Bushfires Royal Commission (VBRC)[20]
- costs arising from an emissions trading scheme
- a natural disaster event
- an insurance event/legal liability above insurance cap event
- an insurer credit risk event.[21]

JEN agreed with the AER's excluded cost categories in the draft decision however considered that the following should also be excluded from the scheme as uncontrollable expenditure:

- new tariff assignment dispute resolution costs
- ESV fees
- Ombudsman scheme costs
- high voltage (HV) injection claims.[22]

14.5.3.3 Submissions

EnergyAustralia was concerned that the AER's might adjust the base opex by removing non-recurrent costs but fail to also remove them from calculation of EBSS carryover amounts.[23]

14.5.3.4 Issues and AER considerations

The AER notes that the natural disaster event, and insurance event/legal liability above insurance cap event and an insurer credit risk event listed by CitiPower and Powercor have been nominated by the AER as pass through events for 2011–15. If the events occur, and they meet the materiality threshold, the costs of the events will be excluded from the EBSS.

The AER has recognised that the remaining events listed by CitiPower and Powercor will be regulatory change events (AEMO fees event are classified as a tax change event) or service standard events under the NER.[24] This is discussed in chapter 16 of this final decision. When or if regulatory change events or service standard events occur, the Victorian DNSPs can apply to the AER to have them assessed under the pass through framework.

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20 Applicable only to Powercor.

21 CitiPower, *Revised Proposal*, p. 394; Powercor, *Revised Proposal*, pp. 392-93.

22 JEN, *Revised Proposal*, pp. 275-276.

23 EnergyAustralia, *Submission on the AER's draft regulatory determination*, August 2010, pp. 8-10.

24 Note that regulatory change events must substantially affect the manner in which direct control services are provided and must materially increase or decrease the costs of providing direct control services. See chapter 16 for further explanation.

As noted above, regulatory change events or service standard events which are rejected (accepted) by the AER as pass through events will be included (excluded) as opex when calculating EBSS carryover amounts. Events which qualify as pass through events but do not satisfy the materiality threshold will be included as opex when calculating EBSS carryover amounts.

In respect of superannuation schemes, CitiPower and Powercor sought clarification of what the AER's draft decision meant by excluding from the EBSS 'superannuation for defined benefit and retirement schemes'. They considered that it was more appropriately titled 'superannuation costs for defined benefit and accumulation schemes'.

The AER has reviewed the operation of accumulation and defined benefit superannuation schemes in an effort to clarify its draft decision. In accumulation schemes, employers pay a set percentage of total remuneration as superannuation on behalf of employees. This amount is paid into a superannuation scheme of an employee's choice, or the default scheme adopted by the company. Those schemes invest the contributions in assets, such as fixed interest bonds and equities in local and international markets. The number of employees hired, together with their overall remuneration package, therefore directly affects the total value of superannuation contributions paid by the employer. DNSP opex forecasts for labour include their employees' total remuneration package. That is, the opex forecasts for labour include superannuation costs.

In the AER's view, these labour costs are controllable by DNSPs and could go up or down depending on a DNSP's hiring policies. Furthermore, it is noted that for accumulation superannuation schemes, employees bear the risk of fluctuating returns in their superannuation funds due to market volatility, not the employer. Therefore, having regard to the nature of costs arising from superannuation accumulation schemes, the AER considers that the Victorian DNSP can control these costs. The AER will therefore include the costs of these schemes in the calculation of EBSS carryover amounts.

In contrast, defined benefit schemes operated by a contributing employer involve paying contributions that vary based on an actuarial assessment of likely returns, discount rate and funding required to cover liabilities. In this case, the company bears the risk of market fluctuations.

During the recent global financial crisis, employer contributions to defined benefit schemes increased to offset the reduction in returns caused by the collapse of financial markets. The recovery in these markets from the second half of 2009 has seen employer contributions diminish as returns increased. The funds into which contributions are paid have therefore had sufficient capital to cover the payouts to retiring employees. Accordingly, in the draft decision the AER excluded these costs in the calculation of EBSS carryover amounts.

For this final decision, the AER considers that the Victorian DNSPs' defined benefit superannuation schemes are uncontrollable costs and are therefore excluded from calculation of EBSS carryover amounts, consistent with section 2.3.2 of the EBSS guideline.[25]

JEN proposed to exclude from the calculation of EBSS carryover amounts the costs associated with new tariff assignment dispute resolution, ESV fees and Ombudsman scheme costs.

The AER notes that it has amended its tariff reassignment procedures such that the procedures are now akin to those currently in place and will not give rise to new costs for DNSPs. This is discussed in chapter 4 of this final decision. Therefore, the AER concludes that the Victorian DNSPs will not bear additional tariff reassignment costs and therefore there is no need to exclude them from the EBSS.

With respect to dispute resolution costs and Ombudsman fees, the arrangements in place under the tariff reassignment procedures are also akin to those currently in place and will not give rise to new costs for DNSPs. This is also discussed in chapter 4 of this final decision. Notably, the Victorian DNSPs have a clear incentive to minimise disputes with retailers and customers to avoid them progressing to the Ombudsman and therefore avoid the associated Ombudsman costs. Consequently, the AER considers that through their actions, the Victorian DNSPs can control these expenditures. Therefore the AER will include dispute resolution costs and Ombudsman fees in EBSS calculations.

In respect of Energy Safe Victoria fees and charges, these will be considered a regulatory change event or service standard event and when, or if, they occur the Victorian DNSPs can apply to the AER to have them assessed under the pass through framework. If expenditure on these items is approved by the AER, they will be excluded from calculation of EBSS carryover amounts, as per section 2.3.2 of the EBSS guideline.[26]

Regarding HV injection claims[27], the AER concurs with JEN that these can occur for technical reasons and therefore may be the responsibility of the DNSP or be caused by a third party. In the case of third party faults, some of these can be mitigated by a DNSP through design, maintenance and protection systems. Clause 2.3.2 of the EBSS guideline requires a DNSP to justify a proposal to exclude costs categories from the EBSS and must not seek to exclude costs categories that would otherwise be regarded as controllable costs.[28]

In respect of HV injection incidents, the AER has reviewed evidence from the Victorian Bushfire Royal Commission (VBRC) file repository.[29]

The file contains a significant amount of information provided by SP AusNet and Powercor to Energy Safe Victoria and details causes of major incidents between 2006

25 AER, *Efficiency benefit sharing scheme, appendix E,* June 2008, p. 6.
26 AER, *Efficiency benefit sharing scheme, appendix E,* June 2008, p. 7.
27 A HV injection is a fault condition where a higher voltage comes into contact with low voltage equipment. The high voltage fault current is transferred through the low voltage equipment until it grounds to an earth point (or points) This effect can cause significant damage to assets.
28 AER, *Efficiency benefit sharing scheme, appendix E,* June 2008, p. 6.
29 Accessible at http://www.royalcommission.vic.gov.au/Documents/Document-files/Exhibits/ESV-001-002-0005

and 2009. Where a HV injection occurred, over three quarters of the incidents (20 of the 26) in the VBRC file were the direct responsibility of the DNSP. Pole and cross arm fires are the most common reason, as well as broken ties and insulators. Of the remainder of incidents, it is not clear if vegetation related faults were caused by vegetation inside or outside clearance zones. It is noted that vegetation inside a clearance zone is the responsibility of the DNSP.

Having regard to the above information, the AER considers that it is reasonable to conclude that a high proportion of HV injection incidents are the responsibility of the DNSP. On this basis, the AER considers that HV injection claims are controllable costs[30] and therefore will be included in calculating carryover amounts under the EBSS.

In respect of CitiPower and Powercor's contention that the financial failure of a retailer event be treated as an uncontrollable costs, AER considers that failure of a retailer equates to a bad debt for the Victorian DNSPs, however DNSPs' opex is not affected by the occurrence of such an event and therefore will not impact on the operation of the EBSS. Therefore, the AER will not exclude the financial failure of a retailer event from the calculation of EBSS carryover amounts.

The AER notes that EnergyAustralia's concerns relating to the operation and application of the EBSS largely concern the application of the EBSS in the NSW distribution determination. The AER notes that it will take into account DNSPs actual opex during 2011–15 when establishing the base forecast opex for the 2016–20 regulatory control period. This same approach will apply in NSW.

14.5.3.5 AER conclusion

Accumulation superannuation schemes costs, dispute resolution costs and Ombudsman fees and costs associated with HV injection claims will be included as controllable costs in the EBSS.

14.5.4 Application of EBSS formula

14.5.4.1 AER draft decision

The AER's draft decision set out the formulae (reproduced in section 1.2 above) to calculate efficiency gains or losses under the EBSS, to be applied to the revenue requirement in the 2016–20 regulatory control period.

14.5.4.2 Victorian DNSP revised regulatory proposals

United Energy considered that:

- the opex efficiency carryover amounts from 2006–2010 should be incorporated into the building block revenue requirement for 2011–2015, without merging the ECM and EBSS

[30] AER, *Efficiency benefit sharing scheme, appendix E*, June 2008, p. 6.

- the EBSS should start anew in 2011, with the first year formula, as shown on page 600 of the AER's draft decision, taking effect. That is, the final year formula adopted in the draft decision should not be applied in 2011.

14.5.4.3 Issues and AER considerations

Regarding the opex efficiency carryover amounts from 2006–2010 and the close out of United Energy's ECM, the AER's final decision is to not apply the ECM associated with efficiencies arising from the current regulatory period (2006–10) to United Energy. The reasoning is set out in chapter 13.

Regarding United Energy's position on the application of the EBSS' first and sixth year formulae, the AER notes that using the first year formula fails to recognise efficiency gains made in 2010.

It measures the efficiency gain made between the base year, 2009, and the first year, 2011, but assumes that no efficiency gains or losses are made in 2010. Thus the first year formula will carry over efficiency gains made in 2010 for six years rather than five. The year six formula subtracts the efficiency gains made in 2010 to ensure that only the efficiency gains made in 2011 are measured. This ensures that efficiency gains or losses made in the current regulatory control period are not included in the EBSS for the forthcoming regulatory control period.

AER conclusion

The AER considers that the year six formula should be used to measure efficiency gains made in 2011 as set out in section 14.5.4.1. The AER considers that this ensures that efficiency gains or losses made in the current (2006–10) regulatory control period are not included in the EBSS for the forthcoming regulatory control period.

14.6 AER conclusion

In accordance with cl. 6.12.1(9) of the NER, the AER's final decision on how the EBSS will apply is as follows. The AER's final decision on the application of the EBSS can also be found in the determination documents for CitiPower, Powercor, JEN, SP AusNet and United Energy.

The AER will apply the EBSS to the five Victorian DNSPs in accordance with its Framework and approach paper published in May 2009 and the EBDSS guideline published in June 2008. The AER notes that none of the five Victorian DNSPs have proposed any changes to their capitalisation policies for the 2011–2015 regulatory control period. If any of the Victorian DNSPs change their capitalisation policies during the forthcoming regulatory control period the AER will adjust the forecast opex amounts used to calculate carryovers to ensure consistency with the capitalisation policy used to calculate actual opex amounts.

The AER will also allow adjustments to EBSS calculations for the consequences of changes in growth for these DNSPs for the forthcoming regulatory control period. The AER considers that the growth adjustment should be consistent with the method used to escalate opex for forecast network growth in this final decision in appendix J.

In accordance with section 2.3.2 of the EBSS and this final decision, the AER concludes that the following will be excluded from calculation of EBSS carryover amount for the forthcoming regulatory period:

- superannuation costs for defined benefits schemes
- DMIA expenditure
- expenditure on non-network alternatives
- recognised pass through events and recognised regulatory change events or service standard events. However the AER clarifies that regulatory change events or service standard events which are rejected by the AER as pass through events will be included as opex when calculating EBSS carryover amounts. Events which qualify as pass through events but do not satisfy the materiality threshold will be included as opex when calculating EBSS carryover amounts.

In addition, in order to meet the requirements set out in clause 6.5.8(c)(2) of the NER in implementing the EBSS, the AER will exclude the following cost categories from the operation of the EBSS in the forthcoming regulatory control period. Specifically, the exclusion of these cost categories will provide the Victorian DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure:

- debt raising costs
- self insurance costs
- GSL payments.

All other costs categories relating to standard control services opex will be included by the AER in the calculation of carryover amounts under the EBSS. Events which qualify as pass-throughs but do not satisfy the materiality threshold will be included as opex when calculating EBSS carryover amounts.

The AER's controllable opex forecasts for the Victorian DNSPs are outlined in the tables below and will be used to calculate efficiency gains and losses for the forthcoming regulatory control period, subject to adjustments required by the EBSS.[31]

The derivations of the AER's controllable opex forecasts for the Victorian DNSPs are discussed further in chapter 7 of this final decision.

[31] ibid., pp. 5–7.

Table 14.2 AER conclusion on CitiPower's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	45.17	45.20	46.40	45.87	46.97	229.60
Adjustment for debt raising costs	-0.69	-0.74	-0.78	-0.83	-0.87	-3.91
Adjustment for self insurance	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for defined benefit superannuation	-0.70	-0.54	-0.39	-0.24	-0.11	-1.98
Adjustment for non-network alternatives	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for DMIA	-0.20	-0.20	-0.20	-0.20	-0.20	-1.00
Adjustment for GSL payments	-0.02	-0.01	-0.01	-0.01	-0.01	-0.07
Forecast opex for EBSS purposes	**43.55**	**43.71**	**45.02**	**44.58**	**45.77**	**222.64**

Note: Totals may not add up due to rounding.

Table 14.3 AER conclusion on Powercor's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	156.90	159.44	157.40	161.98	165.70	801.42
Adjustment for debt raising costs	-1.16	-1.24	-1.32	-1.39	-1.46	-6.57
Adjustment for self insurance	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for defined benefit superannuation	-2.0	-1.4	-0.8	-0.2	0.3	-4.11
Adjustment for non-network alternatives	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for DMIA	-0.60	-0.60	-0.60	-0.60	-0.60	-3.00
Adjustment for GSL payments	-1.15	-1.12	-1.09	-1.06	-1.04	-5.45
Forecast opex for EBSS purposes	**151.98**	**155.10**	**153.60**	**158.70**	**162.91**	**782.29**

Note: Totals may not add up due to rounding.

Table 14.4 AER conclusion on JEN's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	56.04	54.90	55.08	60.01	59.00	285.02
Adjustment for debt raising costs	-0.44	-0.46	-0.48	-0.50	-0.52	-2.41
Adjustment for self insurance	-0.10	-0.10	-0.10	-0.10	-0.10	-0.52
Adjustment for defined benefit superannuation	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for non-network alternatives	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for DMIA	-0.20	-0.20	-0.20	-0.20	-0.20	-1.00
Adjustment for GSL payments	-0.02	-0.02	-0.02	-0.02	-0.02	-0.09
Forecast opex for EBSS purposes	**55.28**	**54.12**	**54.28**	**59.18**	**58.15**	**281.01**

Note: Totals may not add up due to rounding.

Table 14.5 AER conclusion on SP AusNet's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	158.82	165.58	171.31	179.95	182.40	858.07
Adjustment for debt raising costs	-1.12	-1.20	-1.30	-1.40	-1.49	-6.50
Adjustment for self insurance	-1.30	-1.30	-1.30	-1.30	-1.30	-6.50
Adjustment for defined benefit superannuation	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for non-network alternatives	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for DMIA	-0.60	-0.60	-0.60	-0.60	-0.60	-3.00
Adjustment for GSL payments	-4.23	-4.12	-4.02	-3.92	-3.82	-20.12
Forecast opex for EBSS purposes	**151.58**	**158.36**	**164.10**	**172.73**	**175.19**	**821.95**

Note: Totals may not add up due to rounding.

Table 14.6 AER conclusion on United Energy's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	**2012**	**2013**	**2014**	**2015**	**Total**
Total forecast opex	105.84	107.99	108.56	112.78	114.28	549.46
Adjustment for debt raising costs	-0.74	-0.80	-0.85	-0.88	-0.90	-4.16
Adjustment for self insurance	-0.02	-0.02	-0.02	-0.02	-0.02	-0.12
Adjustment for defined benefit superannuation	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for non-network alternatives	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for DMIA	-0.40	-0.40	-0.40	-0.40	-0.40	-2.00
Adjustment for GSL payments	-0.26	-0.26	-0.25	-0.24	-0.24	-1.26
Forecast opex for EBSS purposes	**104.41**	**106.51**	**107.04**	**111.24**	**112.73**	**541.93**

Note: Totals may not add up due to rounding.

15 Service target performance incentive scheme (STPIS)

15.1 Introduction

This chapter outlines the application of the AER's service target performance incentive scheme (STPIS) to the Victorian DNSPs in the 2011–15 regulatory control period.[1]

The STPIS provides financial incentives for DNSPs to maintain and improve service performance. This balances the incentive in the regulatory framework for DNSPs to reduce costs at the expense of service quality. Cost reductions are beneficial to both DNSPs and their customers when service performance is maintained or improved. However, cost efficiencies achieved at the expense of service performance are not desirable.

The STPIS establishes targets based on historical performance, and provides financial rewards for DNSPs exceeding performance targets and financial penalties for DNSPs failing to meet targets. The STPIS has two components, the S factor and the GSL scheme. The S factor component adjusts the revenue that a DNSP earns depending on reliability of supply and customer service performance. The GSL scheme sets threshold levels of service for DNSPs to achieve, and requires direct payments to customers who experience service worse than the predetermined level. The national GSL scheme does not apply in a jurisdiction if a jurisdictional GSL scheme is in existence.

15.2 Regulatory requirements

Clause 6.6.2(a) of the National Electricity Rules (the NER) requires that the AER publish an incentive scheme (the STPIS) to provide incentives for DNSPs to maintain and improve performance.

In developing the STPIS, clause 6.6.2 of the NER requires the AER to consult with authorities responsible for the administration of jurisdictional legislation and to ensure that service standards and targets do not put at risk a DNSP's ability to comply with jurisdictional service standards and targets.

Further, under clause 6.6.2(b)(3) of the NER, in developing and implementing the STPIS, the AER must take into account:

> (i) the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs; and

[1] The AER published its national distribution STPIS on 26 June 2008 (Version 01.0). On 8 May 2009, the AER published an amended STPIS (Version 01.1) to address issues regarding the interaction between the cap on revenue at risk and the equation for the calculation of the S factor, and to clarify the operation of the scheme. On 25 November 2009, the AER published a further amended STPIS (Version 01.2) which primarily addressed how the Major Event Day (MED) boundary is calculated. Details of the STPIS are available from www.aer.gov.au.

(ii) any regulatory obligation or requirement to which the DNSP is subject; and

(iii) the past performance of the distribution network; and

(iv) any other incentives available to the DNSP under the Rules or a relevant distribution determination; and

(v) the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels; and

(vi) the willingness of the customer or end user to pay for improved performance in the delivery of services; and

(vii) the possible effects of the scheme on incentives for the implementation of non-network alternatives.

The NER states that the STPIS is to operate concurrently with any average or minimum service standards and GSL scheme that applies to a DNSP under jurisdictional electricity legislation.

Under clause 2.1(d) of the STPIS, the AER is required to determine the following in accordance with the implementation of this scheme in a revenue determination:

(1) each applicable component and parameter to apply to a DNSP including the method of network segmentation for the reliability of supply component

(2) the revenue at risk to apply to each applicable component and parameter

(3) the incentive rate to apply to each applicable parameter including the value of customer reliability (VCR) to be applied in accordance with clause 3.2.2(d) and appendix B

(4) the performance target to apply to each applicable parameter in each regulatory year of the regulatory control period

(5) any decision with respect to the transitional arrangements set out in clause 2.6

(6) the threshold to apply to each applicable GSL parameter

(7) the payment amount to apply to the applicable GSL parameter

(8) the major event day boundary to apply to a DNSP:

  (i) where the DNSP has proposed a major event day boundary that is greater than 2.5 standard deviations from the mean; or

  (ii) where the major event day boundary that applied to the DNSP in previous distribution determinations was greater than 2.5 standard deviations from the mean; or

  (iii) where the DNSP has proposed a major event day boundary that is greater than 2.5 standard deviations from the mean and where in previous distribution determinations the major event day boundary that has applied to the DNSP was greater than 2.5 standard deviations from the mean.

The AER has also taken into account the National Electricity Objective set out in section 7 of the National Electricity Law (NEL), and the revenue and pricing principles in section 7A of the NEL as required by section 16 of the NEL when exercising its discretion.

The AER's conclusions addressing the requirements of clause 2.1(d) of the STPIS for each of the Victorian DNSPs are outlined in section 15.7 of this chapter.

15.3 AER draft decision

In making its draft decision pursuant to clause 6.12.1(9) of the NER, the AER had regard to the requirements under clause 6.6.2(b) of the NER and considered all submissions made on the STPIS pursuant to clause 6.10.1 of the NER. The AER’s draft decision on how the STPIS is to apply to the Victorian DNSPs can also be found in the draft determination documents for CitiPower, Powercor, Jemena Electricity Networks (JEN), SP AusNet and United Energy. The AER concluded that:

- it would apply the SAIDI, SAIFI and MAIFI reliability parameters to the Victorian DNSPs, as set out in the STPIS. For transitional reasons, the AER will apply the ESCV's definition of MAIFI
- it would apply the caps on revenue at risk as set out in table 15.1
- it would apply the incentive rates in table 15.2 to the reliability and customer service parameters consistent with methodology set out in sections 3.2.2 and 5.3.2(a)(1) of the STPIS respectively
- it would segment the reliability parameters by network type in accordance with the STPIS and apply the targets to these parameters as set out table 15.3
- it would close out the ESCV S factor scheme by applying the methodology set out in section 15.7.12 of the draft decision. The adjustments to the building blocks are set out in table 15.4
- it is bound to apply the existing Victorian GSL scheme under the Electricity Distribution Code and the Public Lighting Code, while this scheme remains in place
- it will allow the forecast GSL opex allowance pursuant to clause 6.5.6(a)(2) of the NER as set out in table 15.5
- the Major Event Day (MED) threshold is to be calculated in accordance with section 3.3 of the STPIS and is to be based on the beta values set out in table 15.6
- for the purpose of the distribution tariff calculation, the S_t factor applied to the weighted average price cap (WAPC) formula for 2011 and 2012 would be zero.

Table 15.1 AER draft decision on cap on revenue at risk (per cent)

	Cap on revenue at risk
CitiPower	±5
Powercor	±5
JEN	±5
SP AusNet	±7
United Energy	±5

Source: AER analysis.

Table 15.2 AER draft decision on incentive rates for SAIDI, SAIFI, MAIFI and the telephone answering parameter (per cent per unit)

	CitiPower	JEN	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI	0.1731	–	–	–	–
SAIFI	9.2794	–	–	–	–
MAIFI	0.7424	–	–	–	–
Urban	–	–	–	–	–
SAIDI	0.0660	0.1299	0.0577	0.0444	0.1432
SAIFI	3.2702	7.8702	3.7592	3.0734	8.7494
MAIFI	0.2616	0.6296	0.3007	0.2459	0.6999
Rural short	–	–	–	–	–
SAIDI	–	0.0054	0.0323	0.0350	0.0152
SAIFI	–	0.3497	2.5761	3.0267	0.9385
MAIFI	–	0.0280	0.2061	0.2421	0.0751
Rural long	–	–	–	–	–
SAIDI	–	–	0.0280	0.0157	–
SAIFI	–	–	2.8058	1.3457	–
MAIFI	–	–	0.2245	0.1077	–
Telephone answering parameter	–0.040	–0.040	–0.040	–0.040	–0.040

Source: AER analysis.

Table 15.3 AER draft decision—performance targets for SAIDI, SAIFI, MAIFI and the telephone answering parameter

	CitiPower	JEN	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI (average minutes)	11.27	–	–	–	–
SAIFI (average interruptions)	0.186	–	–	–	–
MAIFI (average interruptions)	0.026	–	–	–	–
Urban	–	–	–	–	–
SAIDI (average minutes)	22.36	68.50	82.47	105.62	55.09
SAIFI (average interruptions)	0.450	1.127	1.263	1.520	0.899
MAIFI (average interruptions)	0.175	0.776	1.412	2.519	1.074
Rural short	–	–	–	–	–
SAIDI (average minutes)	–	153.15	114.81	214.73	99.15
SAIFI (average interruptions)	–	2.588	1.565	2.697	1.742
MAIFI (average interruptions)	–	1.940	2.881	5.421	2.122
Rural long	–	–	–	–	–
SAIDI (average minutes)	–	–	233.76	267.10	–
SAIFI (average interruptions)	–	–	2.540	3.378	–
MAIFI (average interruptions)	–	–	6.535	8.996	–
Telephone answering parameter (per cent)	68.94	57.46	62.62	76.62	58.14

Source: AER analysis.

Table 15.4 AER draft decision on the building blocks resulting from the ESCV S factor close out ($, million)

	2011	2012	2013	2014	2015
CitiPower	0.15	–2.82	–3.32	–0.22	–6.89
Powercor	16.25	–7.57	–4.49	0.78	–28.71
JEN	–2.17	0.27	0.74	0.76	0.40
SP AusNet	19.97	2.33	–5.11	0.83	–46.80
United Energy	–4.95	–18.81	–17.76	–18.15	–41.96

Source: AER analysis.

Table 15.5 AER draft decision on annual total GSL payments ($, nominal)

DNSP	AER draft decision
CitiPower	15 470
Powercor	1 176 156
JEN	18 892
SP AusNet	4 339 295
United Energy	266 810

Source: AER analysis.

Table 15.6 AER draft decision on MED threshold to be set X beta from the mean

MED thresholds	AER draft decision
CitiPower	2.5
Powercor	2.8
JEN	2.5
SP AusNet	2.8
United Energy	2.5

Source: AER analysis.

15.4 Victorian DNSP revised regulatory proposals

All Victorian DNSPs accepted that the SAIDI, SAIFI and MAIFI reliability parameters would apply for the 2011–15 regulatory control period and that the telephone answering customer service parameter would apply. For transitional reasons, the ESCV's existing definition of MAIFI will continue to apply. All Victorian DNSPs accepted the AER's decision regarding the caps on revenue at risk under the STPIS. The following sections set out the key points of each Victorian DNSP's revised regulatory proposal.

15.4.1 CitiPower

- CitiPower adopted the position in the AER's draft determination for the STPIS except for the ESCV S factor close out.[2]
- CitiPower submitted that the S factor close out term should be added to the control mechanism. CitiPower proposed that its estimated performance for the purpose of the S factor close out be the 2005–09 average performance.[3]
- CitiPower adopted the AER's draft decision regarding the customer service parameter. It noted that the change in definition of this parameter means that the target set in this determination cannot be compared to the targets set by the ESCV, or to the targets of DNSPs in other jurisdictions.[4]

15.4.2 Powercor

- Powercor adopted the position in the AER's draft determination for the STPIS except for the ESCV S factor close out.[5]
- Powercor submitted that the S factor close out term should be added to the control mechanism. Powercor proposed that its estimated performance for the purpose of the S factor close out be the 2005–09 average performance.[6]
- Powercor adopted the AER's draft decision to apply a MED threshold based on 2.8 beta from the mean.[7]
- Powercor adopted the AER's draft decision regarding the customer service parameter. It noted that the change in definition of this parameter means that the target set in this determination cannot be compared to the targets set by the ESCV, or to the targets of DNSPs in other jurisdictions.[8]

15.4.3 JEN

- JEN adopted the AER's customer service target in the draft decision.[9]

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2 CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 397.
3 CitiPower, *Revised regulatory proposal*, p. 398.
4 ibid.
5 Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 396.
6 Powercor, *Revised regulatory proposal*, p. 396.
7 ibid.
8 ibid, p. 396, 397.
9 JEN, *Revised Regulatory Proposal 2011–15*, 20 July 2010 p. 287.

- JEN incorporated the AER's draft decision on climate change in its revised regulatory proposal. However, it expressed concerns about the impact of climate change and sought further capex over the 2011–15 regulatory control period.[10]

- JEN adopted the AER's draft decision to apply the ESCV's MAIFI definition. JEN proposed that the AER modify the definition of MAIFI from a one minute period to a five minute period in its initial regulatory proposal. JEN noted its disappointment that its reasoning for a change in the definition was ignored in the AER draft decision and, by implication, rejected.[11]

- JEN requested that the AER provide specification of how the 'St' parameter in the price control for standard control services will be calculated during the 2011–15 regulatory control period.[12]

- JEN adopted the AER's draft decision that the MED threshold not be fixed for the regulatory control period.[13]

- JEN believed that the AER’s proposal for a final true up adjustment to the 2016–20 building block revenue requirement at the 2015 price review does not adequately address its concerns regarding fair and accurate true up for the transition to the STPIS. JEN proposed that the best solution is an adjustment to 2013 tariffs.[14]

- JEN generally supported the AER's interpretation of the double application of the MED threshold and requested that the AER amend the STPIS to more clearly reflect this interpretation. Otherwise, JEN proposed that its interpretation should be adopted.[15]

- JEN adopted the AER’s GSL draft decision and noted its preference for a national scheme.[16]

15.4.4 SP AusNet

- SP AusNet adopted the AER's draft decision to cap the STPIS revenue at risk at 7 per cent.[17]

- SP AusNet welcomed the AER's draft decision to change the MED threshold from 2.5 beta to 2.8 beta, but again proposed a threshold of 3.2 beta from the mean. SP AusNet submitted that:

  - a beta lower than 3.2 will make inappropriate distinctions between similar outage events

[10] JEN, *Revised regulatory proposal*, p. 281.
[11] ibid., p. 283.
[12] ibid., p. 285.
[13] ibid., p. 286.
[14] ibid., p. 23.
[15] ibid, p. 283, 284.
[16] ibid, p. 284, 289.
[17] SP AusNet, *Electricity Distribution Price Review Revised Regulatory Proposal*, July 2010, p. 33.

    - at 2.8 beta there will be events within SP AusNet's control, hence there will be a perverse incentive to not respond to such events
    - a higher beta will reduce volatility in performance as action will be taken to reduce infrequent, large events.[18]

- SP AusNet disagreed with the draft decision to not exclude supply interruptions due to demand management schemes. It again proposed that load shedding or load interruptions due to failures of non network solutions be excluded from the STPIS.[19]
- SP AusNet adopted the AER's draft decision on the close out and true up of the ESCV S factor scheme.[20]
- SP AusNet proposed a variation to clause 3.3 of the STPIS to include an additional exclusion event for supply interruption due to the suppression of auto reclose devices in high bushfire risk areas.[21]
- SP AusNet proposed that the STPIS formally states that the targets for future regulatory control periods will be set based on DNSPs' capped performance rather than actual performance. This would ensure that the benefits, or penalties, from performance outside the cap are eventually paid out to the DNSP or end users.[22]
- SP AusNet proposed to allow the STPIS voluntary banking mechanism to operate before the revenue cap.[23]
- SP AusNet adopted the customer service parameter draft decision as calculated by the AER using previously supplied monthly data.[24]
- SP AusNet adopted the AER's draft GSL forecasts on the basis that the Victorian GSL scheme continues to apply.[25]
- SP AusNet adopted the AER's draft decision to apply the ESCV's MAIFI definition in the 2011–15 regulatory control period.[26]
- SP AusNet submitted that the AER misunderstood its climate change analysis. It re-submitted a revised climate change adjustment model.

15.4.5 United Energy

- United Energy submitted that there was no objectively correct mechanism for closing out the ESCV S factor scheme. Therefore, it proposed that the scheme not proceed from 31 December 2010 and that no close out amount be included in the

18 SP AusNet, *Revised regulatory proposal*, p. 35–43.
19 ibid., pp. 43–44.
20 ibid., pp. 51–52.
21 ibid., p. 48.
22 ibid., p. 34.
23 ibid., pp. 33–34.
24 ibid., p. 44.
25 ibid., pp. 50–265.
26 ibid., p. 44.

building blocks for the 2011–15 regulatory control period. United Energy also contended that the AER's draft decision was inconsistent with the National Electricity Objective. This is because efficient investment to improve network reliability cannot be achieved if random or arbitrary penalties are imposed unexpectedly on businesses. United Energy considers that the appropriate way to close out the ESCV S factor scheme is through the price control formula.[27]

- United Energy adopted the AER's draft decision regarding the customer service parameter and noted that it provided the AER with the data necessary for the AER to remove the effects of excluded events from the parameter.[28] United Energy noted that there would not have been such confusion over the calculation of the telephone answering measure if the AER had provided a formal definition in the STPIS.[29]

- United Energy changed its GSL payment method in 2008 from paying for both late re-connections and delayed new connections, to only paying for late new connections. United Energy submitted that in the draft decision, the AER used the reported series for the sum of new connections and re-energisation connections from 2004 to 2008, but then inappropriately added the 2009 results where GSLs only applied to new connections.[30] It submitted that the allowance using a forecast of GSL payments only incorporating new connections should be $262 072.

- United Energy contended that the AER failed to maintain a consistent approach to its determination of the standards for reliability performance measurement and of the calculation of the MED threshold.[31]

- United Energy adopted the AER's draft SAIDI, SAIFI and MAIFI targets. However, it submitted that the AER changed the monthly figures United Energy had submitted for planned SAIDI and aggregate customer numbers. However, United Energy noted that the correct customer numbers were used in the calculation of supply reliability targets.[32]

- United Energy adopted the AER's draft decision to cap revenue at risk under the STPIS to 5 per cent.[33]

- United Energy agreed with the overall approach to the calculation of incentive rates but believed that inaccurate component data may have been used.[34]

- United Energy submitted that a constant MED threshold be applied for the duration of the 2011–15 regulatory control period.[35]

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27 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, pp. 217–221.
28 United Energy, *Revised regulatory proposal*, p. 292.
29 ibid., p. 291.
30 ibid., p. 293.
31 ibid., pp. 287–288.
32 ibid., p. 289.
33 ibid., p. 290.
34 ibid., p. 290.
35 ibid., pp. 286–287.

15.5 Summary of submissions

The AER received 12 submissions relating to the STPIS in response to its draft decision and the Victorian DNSPs' revised regulatory proposals. A summary of the submissions are provided below, based on the nature of the issue.

15.5.1 Revenue at risk

TRUenergy stated that it supports the AER's STPIS, which caps total regulated revenue. It noted that under the ESCV S factor scheme there is no cap on revenue, which could lead to large S factor revenue being achieved in any one year.[36]

The Energy Users Coalition Victoria (EUCV) noted the asymmetry that would exist in allowing SP AusNet's draft proposal for unlimited revenue at risk. It also contended that the AER's draft decision revenue cap of 7 per cent imposes a higher financial risk to consumers than is warranted. It stated that this aspect of consumer risk was not considered by the AER's draft decision.[37]

15.5.2 Guaranteed service levels

The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria (the Minister) noted that the AER should include a comparison of historical performance based on the existing exclusion criteria and the new exclusion criteria so it is possible to ascertain whether the interests of the worst served consumers will be compromised by reducing the number of events for which GSLs are paid.[38]

15.5.3 STPIS targets

EUCV contended that the AER did not assess whether the targets it set for the 2011–15 regulatory control period would result in a net zero outcome if the targets had been applied to the actual performance in the previous five years.[39] It stated that in the AER's draft determination, some of the proposed inputs and targets are different to those provided in SP AusNet's initial regulatory proposal, and that there is no consistency in the apparent approach. EUCV also commented that it was difficult to assess how the AER arrived at some of its performance targets.[40]

EUCV submitted that the capex set by the ESCV for the 2006–10 regulatory period was set with the expectation that service performance would improve.[41] EUCV was concerned that the AER did not require the DNSPs to have service targets which reflect the 2006–10 allowances.[42] EUCV noted that consumers have paid for consistent increases in capex and opex and there has been little performance

36 TRU Energy, *Submission to the AER - Victorian electricity distribution network service providers distribution determination 2011-2015: Draft decision*, 16 August 2010, p. 5.

37 Energy Users Coalition of Victoria (EUCV), *Submission to the AER - 2010 AER review of Victorian Electricity DBs, EUCV response to AER Draft Decision*, August 2010, p. 45.

38 Minister for Energy and Resources, Submission on the Victorian Electricity Distribution Network Service Providers' regulatory proposals for 2011-2015, 20 August 2010, pp. 9–10.

39 EUCV, *Submission to the AER*, 19 August 2010, p. 45.

40 ibid., p. 45.

41 ibid., p. 46.

42 ibid., p. 46.

improvement in the current period. Also, the AER has set targets that do not increase performance, the EUCV expressed disappointment at this.[43]

EUCV submitted that the STPIS targets should be less than the performance achieved in the past, but that some targets set in the AER's draft decision provide a worse service performance outcome for consumers, especially in the case of JEN's and United Energy's targets.[44]

15.5.4 Transitional issues

The Minister submitted that the specific circumstances of the Victorian DNSPs had not been taken into account in moving from the ESCV S factor scheme to the AER's STPIS. Particularly, in the 2006–10 regulatory period, reliability improvements are funded through the S factor scheme rather than through the expenditure building blocks.[45] The Minister stated that, as a result, customers have been paying for reliability improvements and that the improvements have not effectively been factored into setting the 2011–15 targets, which will result in windfall gains or losses.[46] In addition, the Minister stated that the windfall gains or losses will be magnified by an increase in the value of customer reliability, which provides a perverse incentive for a deterioration in performance during the latter stages of the 2006–10 regulatory period.[47] The Minister submitted that the AER must carefully consider this transitional issue to minimise potential windfall gains and losses, and perverse incentives.[48] The Minister outlined his assertion that if the STPIS targets are based on the average performance of 2006–10, then there will be windfall gains or losses to DNSPs and customers.[49]

The Energy Users Association of Australia (EUAA) noted that it was disappointed that there was no inclusion of a quality of supply parameter in the STPIS because quality of supply has an impact on users which have invested in power quality sensitive capital equipment.[50] The EUAA noted that Victorian DNSPs were required to install quality of supply monitoring equipment as a result of the 2006–10 Electricity Distribution Price Review (EDPR) and that quality of supply incentives were foreshadowed by the ESCV.[51]

15.5.4.1 ESCV S factor close out—calculation methodology

CitiPower engaged PricewaterhouseCoopers (PWC) to review the AER's draft decision for the Victorian DNSPs to ensure consistency during the transition from the ESCV S factor scheme.

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43 EUCV, *Submission to the AER*, 19 August 2010, p. 47.
44 ibid., p. 46.
45 Minister for Energy and Resources, *Submission to the AER*, 20 August 2010, p. 6.
46 ibid., p. 7.
47 ibid., p. 7.
48 ibid., p. 7.
49 ibid., pp. 8–9.
50 Energy Users Association of Australia (EUAA), *Submission to the AER - AER Draft Determination on Victorian electricity distribution prices for the period 2011-2015 and distributors revised proposals*, 19 August 2010, p. 36.
51 EUAA, *Submission to the AER*, 19 August 2010, p. 36.

The PWC report suggested that the AER had ‘not correctly quantified the value of the future increment or decrement to revenue for performance in 2010 that would have resulted from (the) continuation of the ESCV scheme’.[52]

The submission noted that if the S factor scheme was to continue, the payoff for service performance in 2010 would comprise two components:

1. the decrement, or increment, in respect of 2010 performance incurred annually from 2010 to 2015 inclusive
2. an offsetting decrement, or increment, incurred annually from 2011 to 2015 inclusive to the extent that the 2010 performance was ‘randomly bad’ or ‘randomly good’.[53]

The submission added that ‘the combination of the AER’s method for quantifying the value of the future increment or decrement to revenue for performance in 2010 together with its approach for setting the new performance targets means that only the first of these components (will be) taken into (account)'. The PWC report stated that this implies:

> if 2010 turns out to be a ‘randomly bad’ year, then the penalty for 2010 performance will be much larger than intended under the ESCV scheme; whereas if 2010 turns out to be a ‘randomly good’ year, then the reward for 2010 performance will be much larger than intended under the ESCV scheme.[54]

The PWC report examined three potential remedies to appropriately close out the ESCV S factor scheme. The report recommended the second remedy. The potential remedies were to:

1. Set the new performance targets under the AER's scheme at the level of outturn performance in 2010.
2. Reapply the ESCV scheme again for 2011 on the assumption that performance in 2011 returns to the new target, whilst applying the AER's scheme simultaneously to reward, or penalise, any difference between the new target performance and the actual level.[55]
3. Apply the penalty or reward in respect of 2010 performance that would be calculated under the ESCV scheme for a single year rather than applying it for the 6 years that would be the case under the ESCV scheme. However, this remedy is only approximately correct if performance in 2009 was at the underlying level, which cannot be assumed.[56] This option was disregarded.

The PWC report further stated that with the exception of the AER's assumption regarding ongoing performance, it agreed with the AER’s quantification of the value of future increments or decrements to DNSPs' revenue that would have occurred as a result of service performance in the 2006–10 regulatory period.[57]

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52 CitiPower, Powercor, *Submission to the AER – PWC S factor close out report*, 6 August 2010, p. 2.
53 ibid., pp. 2–3.
54 ibid., p. 3.
55 ibid., p. 4.
56 ibid., p. 4.
57 ibid., p. 3.

SP AusNet submitted that it 'accepted and would continue to support, the manner of the payout of the S factor scheme as proposed by the AER in the draft decision'.[58] According to SP AusNet, the major positive of the draft decision approach is that the negative effects of the 2009 bushfires on the reliability payments to SP AusNet are muted under this approach regardless of the 2010 reliability outcomes.[59]

SP AusNet did not believe that the close out approach proposed by CitiPower and Powercor is correct as it does not capture all the ongoing effects of the 2010 performance and therefore does not return the scheme to a neutral position.
SP AusNet noted that the appropriate method to close out the ESCV S factor scheme is to use the S factor payout for 2011 (first year of 2009 performance paid out) and 2012 (first year of estimated 2010 performance paid out) and zeroed out all S factor payouts in subsequent years.[60]

United Energy contended that the ESCV S factor scheme should cease operation from 31 December 2010. United Energy recognised that ceasing the ESCV S factor scheme on 31 December 2010 would result in the scheme not rewarding or penalising network performance for 2009 and 2010 (because the rewards and penalties of the ESCV S factor scheme are applied 2 years in arrears).[61]

15.5.4.2 Final adjustment for 2010 actual performance

CitiPower and Powercor did not agree with the AER's decision not to address the S factor true up in the WAPC formula and to instead leave it for the 2016–20 distribution determination. CitiPower and Powercor submitted that the AER should include a new term in each of the WAPC formula and the side constraint formula to address the S factor true up.[62]

JEN also did not accept the AER's draft decision and stated that 'the AER’s proposal for a true-up adjustment to the 2016–20 building block revenue requirement at the 2015 price review does not adequately address JEN’s concerns regarding fair and accurate true-up for the transition to the AER’s proposed STPIS. JEN is concerned that the AER cannot bind itself, or any future regulator, to give effect to statements of intent at the next price review.'[63]

JEN noted that one of the reasons the AER rejected its S factor true up proposal was that the NER constrains the AER to follow the WAPC formula in the Framework and approach paper. JEN believed that this reasoning is at odds with the AER's introduction of a new ‘pass through’ term into the WAPC formula.[64]

15.5.5 Other issues

EUCV stated that the service performance incentives have provided Victorian users with improved service. It supported the continuation and expansion of the service

58 SP AusNet, *email*,10 September 2010.
59 ibid.
60 ibid.
61 United Energy, *Further comments on Citipower S-factor submission*, p. 6.
62 CitiPower, *Revised proposal*, p. 20; Powercor, *Revised proposal*, p. 20.
63 JEN, *Revised regulatory proposal*, p. 23.
64 ibid., p. 23.

incentives. EUCV noted that poor performing feeders should be targeted by the AER in future reviews.[65]

The Consumer Action Law Centre (CALC) submitted that the AER should not approve SP AusNet's proposal to turn off auto reclose devices during the fire season in high risk areas as recommended by the Victorian Bushfire Royal Commission until a decision by the Victorian Government is taken.[66]

Energy Response contended that the STPIS may act as a disincentive to DNSPs' considerations of non network demand management solutions. Energy Response noted that an exclusion for DNSPs from the STPIS, or a relaxation from the conditions on DNSPs in relation to demand management, would assist in its uptake. Energy Response further contended that flexibility will hasten the implementation of a spectrum of non network options and not only demand side response services.[67]

EUCV noted that in the draft decision, the AER varied the way in which extreme events are excluded and the cap on revenue for different DNSPs. The EUCV contended that the loss of consistency across all DNSPs is unwarranted. It recommended that the AER impose the same approach for all DNSPs. It also expressed concern that a DNSP will seek a change only when there is a benefit, for example gaining a financial reward or minimising penalties.[68]

15.6 Issues and AER considerations

15.6.1 Major Event Day (MED) threshold

This section sets out the consideration of SP AusNet's proposal to increase the MED threshold to 3.2 beta from the mean.

15.6.1.1 AER draft decision

In the draft decision, the AER considered it appropriate to increase SP AusNet's MED threshold from the default of 2.5 to 2.8 beta from the mean, rather than the 3.2 beta proposed by SP AusNet. The AER considered that setting the MED threshold at 2.8 beta from the mean would strengthen the incentives on SP AusNet to improve supply reliability and does not unreasonably increase the volatility of the scheme.[69] Further, at this MED threshold the AER was satisfied that the performance targets would not be unduly influenced by a few very large unusual events. The AER considered that a MED threshold as high as 3.2 beta from the mean was not in accordance with the objectives of the STPIS, in that consumers would not necessarily receive a commensurate benefit.[70]

Additionally, the AER noted that its STPIS replaces the scheme previously administered by the ESCV and that the experience of both customers and SP AusNet

65 EUCV, *Submission to the AER*, 19 August 2010, p. 44.
66 Consumer Action Law Centre, *Submission to the AER's Victorian Draft Distribution Determination 2011- 2015*, 19 August 2010. pp. 5–6.
67 Energy Response, *Submission to the AER - Draft decision and draft determinations for the Victorian DBs*, 17 August 2010, p. 2.
68 EUCV, *Submission to the AER*, 19 August 2010, pp. 45–46.
69 AER, *Draft decision*, 2010, p. 653.
70 ibid., p. 653.

under the new scheme is at this time untested. As such, the AER considered it prudent to only allow a measured change in the MED.[71]

15.6.1.2 Victorian DNSP revised regulatory proposals

SP AusNet presented additional analysis to support its proposal for an increase in its MED threshold to 3.2 beta from the mean.

> SP AusNet welcomes the AER's decision to relax the MED threshold from 2.5 beta, but it is disappointing that the AER has adopted a threshold of 2.8 beta rather than the 3.2 beta proposed by SP AusNet. In this Revised Proposal, SP AusNet explains why it remains convinced that the 3.2 beta threshold would deliver a better overall outcome compared with the AER's 2.8 beta in its Draft Determination.
>
> SP AusNet accepts the AER's view that a tension exists between providing incentives to improve reliability of supply and the size of the potential rewards and penalties offered under the STPIS. In addition, SP AusNet acknowledges the AER's concern that increasing the beta threshold may have the following adverse outcomes for the STPIS:
>
> - payouts may be more volatile; and
> - the target performance may be incorrectly set.[72]

While accepting that these tensions exist, SP AusNet contended that the volatility of payouts is dealt with appropriately by the 7 per cent cap on the revenue at risk and the banking mechanism. As such, SP AusNet contended that the AER's concerns regarding this volatility have been addressed. SP AusNet also believed that the AER's concerns that the performance targets may be incorrectly set at higher betas, does not arise until the MED threshold is set greater than 3.2 beta.[73]

A summary of SP AusNet's additional arguments in favour of a MED threshold set 3.2 beta from the mean follows:

> - SP AusNet has analysed its historic performance data to understand which types of events are within the company's control. The analysis, whilst imperfect, indicates that very similar events can be observed at thresholds of 2.5 beta and 3.2 beta. Consequently, SP AusNet considers that a beta threshold lower than 3.2 will make inappropriate distinctions between outage events that are essentially very similar. Such an outcome is contrary to a well designed threshold which should distinguish between events that are within the company's control and those that are not.
> - Setting thresholds creates the potential for perverse outcomes at or near the boundary. In SP AusNet's case, a 2.8 beta threshold will cause some events that are potentially within the company's control to be excluded from the STPIS. Any action by SP AusNet to reduce the impact of excluded events can only have a negative financial impact on SP AusNet. This perverse incentive arises because an improvement in performance may cause an excluded event to cross the threshold with the effect of worsening SP AusNet's actual performance under the STPIS. This outcome would be contrary to the purpose of the STPIS

[71] AER, *Draft decision*, 2010, p. 653.
[72] SP AusNet, *Revised regulatory proposal*, p. 37.
[73] ibid., p. 43.

objectives and attainment of the National Electricity Objective, and not in the interests of customers.

- Customers will be concerned about both STPIS payments and network performance, including the impact of events that fall outside the threshold. Excluding events from the STPIS does not remove the impact of these events on customers. The AER is correct that increasing the beta will increase the volatility of bonuses and penalties under the scheme, subject to the overall cap of 7%. However, the AER should also recognise that a higher beta will encourage reduced volatility in network performance as action is taken to reduce the impact of infrequent, large impact events.

- SP AusNet accepts that a judgment is necessary to ensure that the beta threshold is appropriate for each DNSP. In SP AusNet's case, the data indicates that a 3.2 beta is appropriate.[74]

15.6.1.3 Submissions

EUCV noted that, in the draft decision, the AER agreed to vary the way in which extreme events are excluded and the cap on revenue for different DNSPs. EUCV recommended that the AER impose the same approach for all DNSPs. It expressed concern that a DNSP will seek a change only when there is a benefit, for example, gaining a financial reward or minimising penalties.[75]

15.6.1.4 Issues and AER considerations

Accuracy of targets

In its revised proposal, SP AusNet did not agree with the AER's draft decision that the accuracy of SP AusNet's STPIS targets would be adversely affected at 3.2 beta.[76] The AER has considered SP AusNet's comments and concludes that the concerns expressed in the draft decision by the AER with respect to the accuracy of targets remain valid. Particularly, the AER cannot be confident that the STPIS targets, calculated including a small number of very large outage events, accurately represent the underlying reliability of SP AusNet's network.[77] Having regard to clause 6.6.2(b)(3)(i) of the NER, the AER considers that the STPIS targets must be set accurately. This clause requires that the benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs.

As expressed in the draft decision, the AER is concerned of the impact of applying a much higher beta value on performance target accuracy—because the targets increase in discrete steps at higher MED thresholds, rather than in a progressive manner. The following section explains this issue.

The effect of random events on the accuracy of the target

To demonstrate the degree of uncertainty in the accuracy of the targets the AER:

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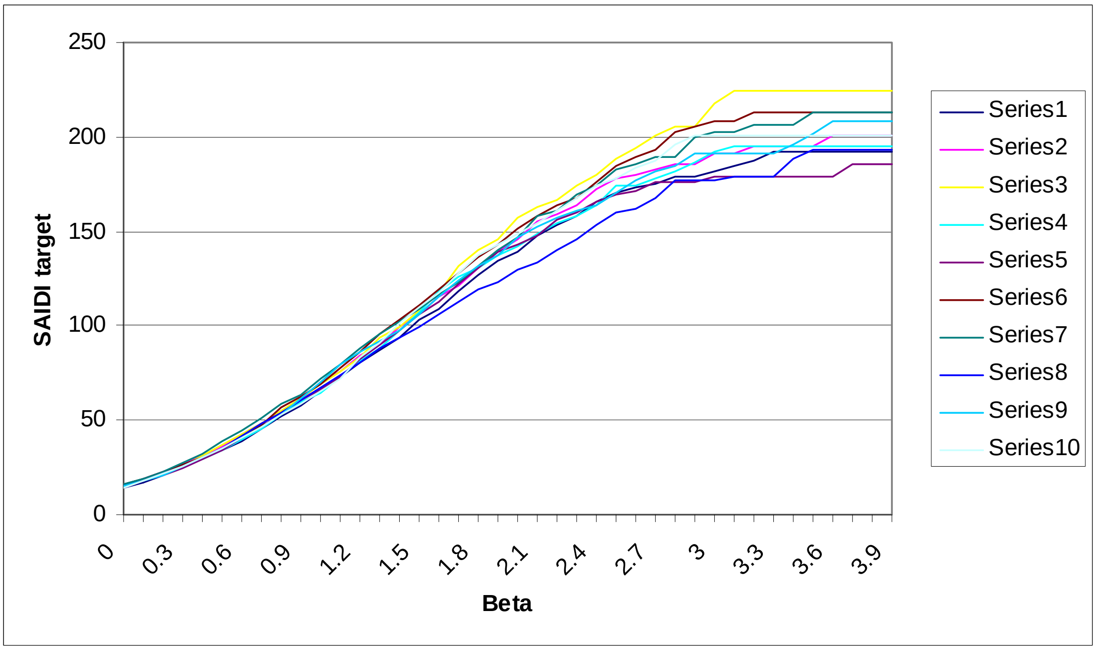
74 SP AusNet, *Revised regulatory proposal*, p. 37, 38.
75 EUCV, *Submission to the AER*, 19 August 2010, p. 45, 46.
76 SP AusNet, *Revised regulatory proposal*, p. 43.
77 At 3.2 beta SP AusNet's exclusion criteria would exclude events that are greater than approximately 20 SAIDI minutes. As such the inclusion of a large outage event, which is one day out of a five year period in the calculation of the performance target could increase the performance targets by approximately 2 per cent.

- generated five year's of SAIDI data (generated from a lognormal distribution)
- calculated all MED thresholds (in 0.1 beta increments) based on this data
- excluded events greater than the respective MED thresholds
- finally calculated the SAIDI target at each of these MED thresholds

The AER repeated this process 10 times.

As can be seen in figure 15.1, STPIS targets calculated from data generated from the same underlying distribution will vary and that the size of the variation increases at higher MED thresholds. As all series of targets are generated from the same distribution, the variations between series do not represent an underlying increase or decrease in supply reliability, but rather are indicative of the degree of variation that may be expected in a DNSP's reliability.[78] It is clear that as the MED threshold increases, the potential size of a windfall gain or loss also increases due to setting the STPIS targets including large infrequent events. The AER considers that the potential for inaccuracy in setting the targets when using high beta values is inconsistent with clause 6.6.2(b)(3)(i) of the NER, which requires that the benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs.

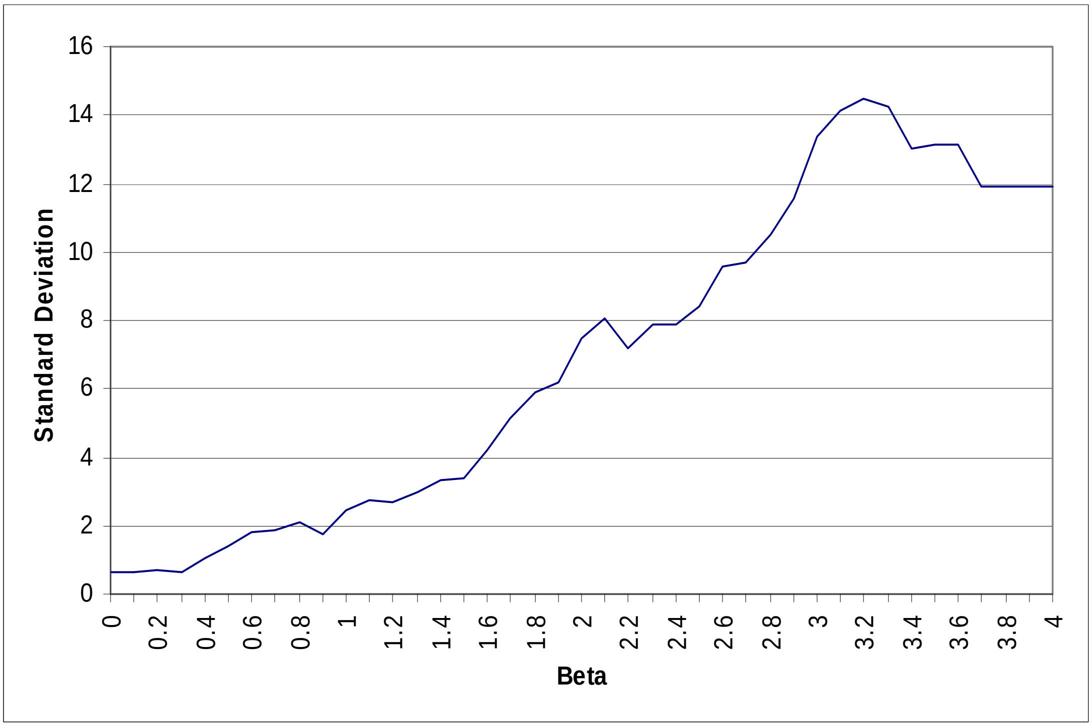
Figure 15.1 Generated SAIDI target from a lognormal distribution



[78] This is analogous to holding a DNSP's network in a roughly consistent condition and only observing the reliability differences cause by random events.

Figure 15.2 shows the standard deviation of the 10 series presented in figure 15.1. These two figures reinforce the AER's view that the accuracy of the target decreases at higher MED thresholds.[79]

Figure 15.2 Standard deviation of SAIDI targets under different beta values



Relationship between STPIS target and MED threshold

SP AusNet contended that its targets do not begin increasing in step changes until around 3.2 beta, which implies that there are enough data points at 3.2 beta to discount this as an issue.[80]

The earlier analysis indicates that the accuracy of the targets decreases as the MED threshold increases. Once the targets start increasing in discrete steps, this would indicate that the lack of data points has reached a critical level. The targets may not increase in discrete steps before 3.2 beta, however, this does not mean that the lack of data points is not adversely effecting the accuracy of the targets. The AER does not consider that setting the MED threshold close to this critical point at 3.2 beta is appropriate; rather, it should be set where the AER has reasonable confidence that the target will be accurate. This takes account of section 6.6.2(b)(3)(i) of the NER which requires the AER to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward, or penalty, under the scheme for DNSPs.

SP AusNet also contended that:

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79 This assumes the network maintains a roughly consistent condition. If there are enduring reliability changes in the network, these will only be reflected slowly in the targets if a larger averaging period is use. The AER considers 5 years is an appropriate period of time to use.

80 SP AusNet, *Revised regulatory proposal*, p. 43.

> the 2.8 beta appears to be the point where the target based on actual data rises above the theoretical target based on a log normal distribution. SP AusNet notes that at a 3.2 beta there is only a very small difference between the log normal distribution and the actual SP AusNet data. SP AusNet therefore considers that the 3.2 beta threshold reasonably reflects the underlying performance of the network.

In its draft decision, the AER placed reasonable caveats on its analysis of this issue.[81] The AER cautioned that the theoretical log-normal distribution does not necessarily reflect the underlying statistical distribution of SP AusNet's network. Such analysis is useful to demonstrate theoretical aspects of the scheme, but should not be used in isolation to calculate or draw firm conclusions regarding the value of targets or parameters. Hence, the AER does not agree with SP AusNet's conclusion that, because the theoretical target was close to the calculated target at 3.2 beta, the calculated target reasonably reflects the underlying performance of the network.

Impact on price

SP AusNet submitted that the revenue cap and the banking arrangements provide the most appropriate mechanism to manage volatility under the scheme. SP AusNet noted that:

> [it] accepts the AER's Draft Determination that a revenue cap of 7% should be adopted. Consequently, SP AusNet believes that the AER's concerns regarding volatility have already been addressed by the imposition of the revenue cap.

The AER has sought to manage the volatility of revenue changes to reach a balance between the size of the reward and penalty, and the actual impact on customers. In doing so, the AER had regard to clause 6.6.2(b)(3)(i) of the NER. This ensures that benefits to consumers likely to result from the scheme are sufficient to warrant any reward, or penalty, under the scheme for DNSPs and also takes into consideration the willingness of customers to pay for improved services pursuant to clause 1.5(b)(6) of the STPIS.

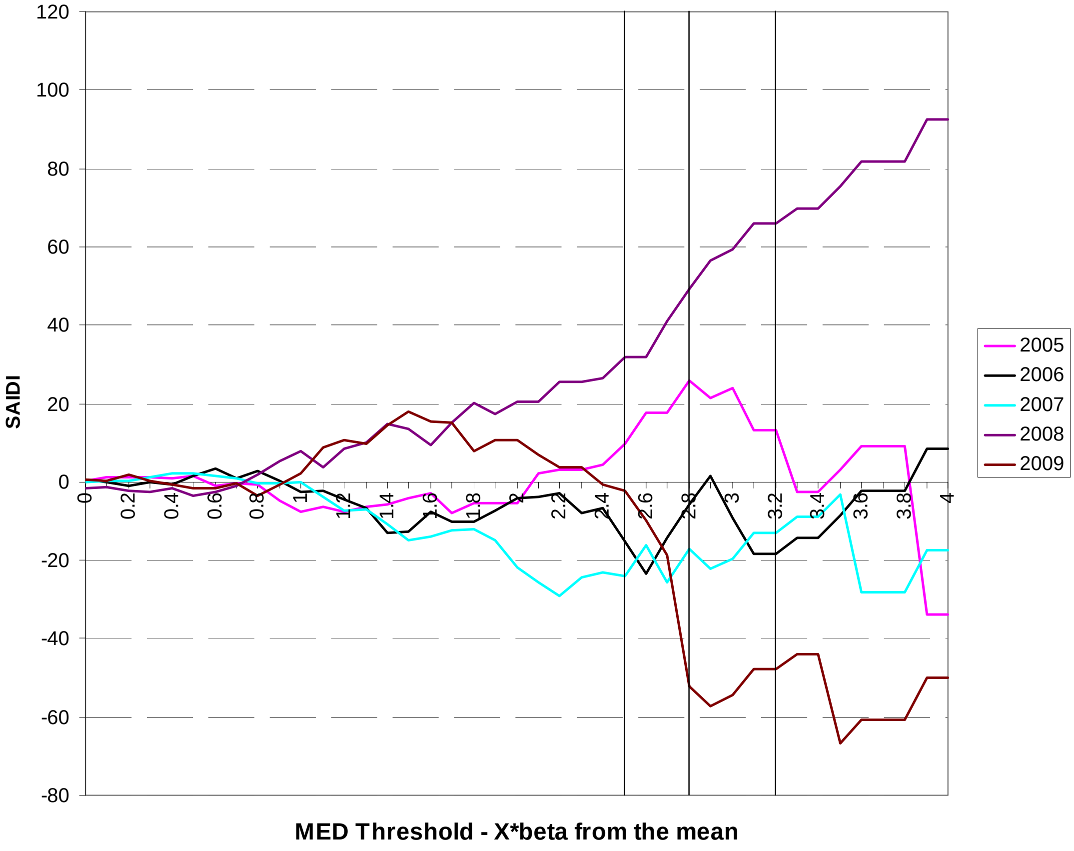
The cap on revenue at risk places an absolute limit on the amount of revenue and tariff volatility that may be present under the STPIS. The AER agrees that by placing a cap on SP AusNet's revenue at risk, rather than the uncapped scheme proposed by SP AusNet in its initial proposal, some concerns regarding tariff volatility are alleviated. However, the AER considers that the cap is only one aspect of risk mitigation within the scheme and that there are still other reasons not to allow the MED threshold to be set at 3.2 beta.

In particular, the cap on revenue at risk only limits the maximum size of the potential swings in revenue, but does not address volatility within the capped range. As the MED threshold increases, there will naturally be larger swings in measured performance and the frequency at which the cap on revenue is reached will increase. The AER does not consider that large swings in revenue resulting from the application of a beta value higher than 2.8 beta are consistent with clause 6.6.2(b)(3)(i) of the NER.

[81] AER, *Draft decision*, p. 650.

The relationship between the MED threshold and the volatility of the outcome of the scheme is shown graphically at figure 15.3, which is reproduced from the draft decision.

Figure 15.3 SP AusNet—Difference between actual and average (target) performance



Potential for perverse incentives

SP AusNet submitted that setting a MED threshold creates the potential for perverse outcomes at, or near, the boundaries of the threshold. SP AusNet also noted that it has developed a storm forecasting tool to improve responses to high activity days. SP AusNet stated that:

> … under the Draft Determination threshold, the use of a system [the storm forecasting tool] to improve reliability to customers from improving responses to days in the range of 10 to 20 minutes USAIDI (20 minutes corresponds to SP AusNet's proposed 3.2 beta threshold) is likely to result in increased penalty payments.[82]

The AER acknowledges SP AusNet's argument that a MED threshold, set at any level, may impact on the incentive for a DNSP to respond to events marginally greater than this threshold, and that it may provide an incentive not to respond to events only marginally smaller than the MED threshold which have the potential to breach it. This is an unavoidable aspect of any quantitative exclusion criteria. The AER also acknowledges SP AusNet's argument that, if SP AusNet improved its response to events greater than the MED threshold this could have a negative financial impact,

82 SP AusNet, *Revised regulatory proposal*, p. 39.

because any improvement sufficient to bring the event below the MED threshold would result in a penalty for SP AusNet. The converse is also true, in that if SP AusNet's response to events just below the MED threshold worsened, more events might fall above the MED threshold resulting in a financial reward.

However, a DNSP systematically varying its response to large outage events to ensure that the event is larger than the MED threshold would be contrary to the NEO, as it does not promote efficient operation and use of electricity services and is not in the long term interests of customers. In addition, the Electricity Distribution Code requires that SP AusNet must use best endeavours to:

- develop and implement good asset management policy, and to maintain and operate its distribution system to minimise the risks associated with the failure or reduced performance[83]

- meet targets required by the Price Determination and the targets published by SP AusNet under clause 5.1 of the Code, and otherwise meet reasonable customer expectations of reliability of supply[84]

SP AusNet contended that setting the MED threshold at 2.8 beta from the mean draws an inappropriate distinction between similar events and stated that:

> a beta threshold lower than 3.2 will make inappropriate distinctions between outage events that are essentially very similar. Such an outcome is contrary to a well designed threshold which should distinguish between events that are within the company's control and those that are not.

SP also stated that:

> Clearly, SP AusNet has the capacity to respond to all events controllable or otherwise – even after a massive 1 in 100 year storm, customers are eventually restored to supply. The issue of control is whether the magnitude of the reliability outcomes from a given event is controllable by that response. That is, is there a proportional relationship between the resources SP AusNet mobilises and commits and the reliability outcome for customers? If there is a proportional relationship, the incentive regime will work as SP AusNet can balance the extra cost of improving the response against the revenue benefit from a predictable increase in reliability.[85]

The AER does not consider that the size of an outage event is an accurate proxy for the degree of control a DNSP has over the outage event. The AER considers that there may be several other factors that would impact on a DNSPs ability to respond to an event other than its size, including the type of event, the timing and the location of the event. Therefore, the AER does not consider that SP AusNet's analysis illustrates that SP AusNet has the ability to respond to events at 2.8 or 3.2 beta, but not above this level.

The AER has considered both the power of the unintended incentive and the frequency with which any unintended incentive may arise. In general, at higher MED thresholds, there are fewer events that would be exposed to these unintended

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[83] clause 3.1 of the EDC.
[84] clause 5.2 of the EDC.
[85] SP AusNet, *response to information request*, 6 August 2010.

incentives—however, these events would be larger and would have a large impact on a DNSP's financial position if they were to fall below the MED threshed. Thus the incentive not to improve responses to these events is greater. At lower MED thresholds the number of events close to the MED threshold increases but the impact of each event is relatively smaller and hence the unintended incentive is not as strong.

Short of removing the MED threshold altogether, which the AER considers would expose the DNSPs and customers to an unacceptable level of risk and revenue volatility, the AER does not consider that changing the MED threshold can remove the potential for these unintended incentives. For the reasons outlined above, the AER considers that with the MED threshold set at 2.8 beta, the STPIS provides appropriate incentives for SP AusNet to improve its service performance.

Further, in response to SP AusNet's arguments regarding perverse incentives, the AER notes that the purpose of the STPIS is to provide incentives for DNSPs to maintain and improve service performance. However, the Electricity Distribution Code also imposes other requirements on DNSPs to use their best endeavours to respond to all supply outage events. Their performance during major event days will be monitored by the AER.[86]

As public reporting of DNSPs performance is one of the key elements that underpins the effectiveness of economic regulatory frameworks, the AER intends to continue to publish annual performance reports of the Victorian DNSPs. These reports will provide customers with comprehensive information about the services they receive, and promote better service—including those services that are not covered by the STPIS—by comparing and encouraging each DNSP to improve its performance relative to other DNSPs.

Impact on customers from higher MED threshold

SP AusNet considers that customers benefit from a higher MED threshold as this encourages improved supply reliability. SP AusNet stated that:

> Increasing the beta threshold to 3.2 does not adversely affect customers, as suggested by the AER. On the contrary, customers will benefit because events previously excluded from the incentive arrangements will now be subject to it. As a result, the costs currently incurred by customers through lower levels of reliability are more likely to be reduced. SP AusNet accepts that the performance target will also be increased, but the increase only reflects the inclusion of more outage events within the scheme. As noted above, the extent of the increase in the target is reasonable when compared against the theoretical log normal distribution.

Using SP AusNet's performance from 2005–09, the AER calculated the percentage of days which SP AusNet would have an incentive to improve performance under a 2.8 beta threshold and a 3.2 beta threshold. With beta set at 2.8 during the 2005–09 regulatory period, SP AusNet would have had an incentive to improve performance on 99.34 per cent of days; whereas, under 3.2 beta this incentive covers 99.73 per cent of days. This represents an additional 1.4 days on average per year under 3.2 beta compared with 2.8. The AER considers that as the STPIS is untested, the benefits customers may receive by providing incentives for SP AusNet to respond to around an

86 Chapter 21 provides details of the AER's proposed outcome monitoring framework.

additional 1.4 days per year are not enough to mitigate the AER's concerns regarding the accuracy of the STPIS targets. That is, the AER considers that increasing the MED threshold raises concerns about whether the benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs. This is one of the factors that the AER must consider when implementing an STPIS under clause 6.6.2(b)(3)(i) of the NER.

National Electricity Objective (NEO) and National Electricity Rules (NER)

SP AusNet considers that setting the MED threshold at 2.8 beta would not be in accordance with the NEO. SP AusNet stated that:

> With regard to the NEO, an inappropriate threshold or exclusion regime discourages efficient operation and investment in reliability of supply of electricity for the reasons outlined above. Therefore, some flexibility in setting the exclusion regime would better meet the objective. Without this, the AER cannot have certainty that the regime will be consistent with the NEL

For the reasons presented above, the AER considers that 2.8 beta is an appropriate exclusion threshold. Further, the AER considers that setting the MED threshold greater than 2.8 beta from the mean may mean that the benefits to consumers are no longer sufficient to warrant any reward or penalty to the DNSPs—which is one of the factors that the AER must consider when implementing an STPIS under clause 6.6.2(b)(3)(i) of the NER. This is because the AER considers that there cannot be confidence in the accuracy of the targets set at 3.2 beta from the mean, and because it is likely to introduce unacceptable volatility of tariffs and revenue into the scheme.

Response to submissions

The EUCV recommended that the AER apply the same exclusion criteria and cap on revenue at risk for all Victorian DNSPs. The EUCV contended that the loss of consistency across all DNSPs is unwarranted, and recommended that the AER imposes the same approach across all the DNSPs and not to allow differences. The AER does not consider that applying different MED thresholds to different DNSPs materially affects the consistency in the treatment of or comparability of the Victorian DNSPs for the following reasons:

- For the purpose of comparison, the DNSPs' performance data can be prepared using a consistent MED threshold. This allows for like for like comparisons, whilst still allowing targeted incentives for individual DNSPs.

- Even if the MED threshold is set the same number of standard deviations from the mean, the actual MED threshold differs between DNSPs due to the different performance characteristics of the DNSPs.

The EUCV also expressed concern that applying different MED threshold to different DNSPs could lead to DNSPs selectively choosing a threshold that delivers a financial reward or minimise penalty to the DNSPs.[87]

DNSPs cannot choose a lower MED threshold than the STPIS default level of 2.5 beta from the mean. However, a DNSP may seek a higher exclusion threshold under the

[87] EUCV, *Submission on revised regulatory proposal*, p. 45.

scheme.[88] Increasing the MED threshold increases the potential size of both benefits and penalties, and hence any increase in financial reward is accompanied by the risk of greater financial penalties. It is conceivable that in future regulatory periods the DNSPs may propose different MED thresholds in response to changing expectations regarding future performance. For example, a DNSP that no longer considers it can improve service performance may seek to apply a lower MED threshold closer to, or at the 2.5 beta minimum level. The AER will take this into account should any DNSP propose a change from its initial position in a future regulatory proposal.

15.6.1.5 AER conclusion

The AER has considered SP AusNet's proposal for its MED threshold to be calculated at 3.2 beta from the mean and concluded that the proposal does not promote the objectives of the STPIS. In reaching this conclusion the AER has had particular regard to section 6.6.2(b)(3)(i) of the NER. If SP AusNet's MED threshold was set at 3.2 beta, the AER considers that it cannot ensure that the benefits to consumers likely to result from the proposal are sufficient to warrant any reward, or penalty, under the scheme for DNSPs.

The AER will apply a beta of 2.5 beta from the mean for CitiPower, JEN and UED as per the STPIS. The AER will apply a beta of 2.8 beta from the mean for Powercor and SP AusNet. As such, the AER will calculate the MED thresholds using the beta values set out in table 15.7.

Table 15.7 AER conclusion—MED threshold set X beta from the mean

MED thresholds	Revised proposal—beta values	AER conclusion—beta values
CitiPower	2.5	2.5
Powercor	2.8	2.8
JEN	2.5	2.5
SP AusNet [a]	3.2	2.8
United Energy	2.5	2.5

[a] In the draft decision, this MED threshold was set at 2.8 beta from the mean.
Source: AER analysis.

15.6.2 Fixed MED Threshold

Under the STPIS, the MED threshold for each year is calculated based on the actual daily SAIDI experience of the five preceding years. In their initial regulatory proposals, United Energy and JEN proposed to hold the MED threshold constant throughout the 2011–15 regulatory control period, rather than recalculating each year as prescribed by the STPIS.

[88] The STPIS does not permit DNSPs to propose a MED threshold lower than the default 2.5 beta from the mean. This prevents DNSPs from lowering the incentive to improve performance below this level.

15.6.2.1 AER draft decision

The AER noted that recalculating the MED threshold each year is an element of the scheme's design, which was widely consulted on during its development. Additionally, the AER found that there is benefit to updating the MED threshold annually to ensure up to date outage information is included in its calculation.[89]

15.6.2.2 Victorian DNSP revised regulatory proposals

United Energy's revised regulatory proposal considered that:

> There is a strong argument that if performance targets are fixed for five years, then the major event day threshold should also be fixed for five years. UED considers that the STPIS should be amended to fix the major event day threshold for five years.[90]

United Energy stated that:

> The AER has sought to justify its position by reference to the IEEE standard…[91]
>
> However, the AER has not properly considered these comments, and the associated analysis of probabilities, in the context in which the IEEE standard was developed. [92]

And:

> Under a regime of an evolving exclusion threshold, there would be less comparability, from one year to the next, between the net results obtained for the reliability measures, unplanned SAIDI, SAIFI and MAIFI. This is because of the change in the effective exclusion trigger in each successive year.
>
> The AER has therefore failed to maintain a consistent approach to its determination of the standards for reliability performance measurement and for the calculation of the major event day exclusion trigger. The fixing of performance targets for a five year period is inconsistent with a rolling five-year average assessment of the exclusion threshold.[93]

15.6.2.3 AER issues and considerations

Changing the nature of the calculation of the MED threshold is not contemplated in the STPIS. The AER does not consider that it can, or that it is appropriate, to change it in this distribution determination. In addition, the AER considers that it is appropriate to update the MED threshold annually, to incorporate the latest available performance data and to account for any ongoing changes in the reliability characteristics of a DNSP's network. This ensures that the MED threshold continues to reflect the underlying nature of the DNSP's network. If a DNSP's network materially improved (or deteriorated) over the regulatory control period, a fixed MED threshold may result in outage events being inappropriately included (or excluded) in its performance measure.

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89 AER, *Draft decision*, p. 655.

90 United Energy, *Revised regulatory proposal*, p. 283.

91 Institute of Electrical and Electronics Engineers standard 1366–2003

92 SP AusNet, *Revised regulatory proposal*, p. 286.

93 United Energy, *Revised regulatory proposal*, p. 288.

15.6.3 Calculation methodology of the MED threshold

15.6.3.1 AER draft decision

In the draft decision, the AER determined that CitiPower, Powercor and SP AusNet had interpreted clause 3.3 of the STPIS in accordance with the intention and purpose of the STPIS. The AER did not consider this to be the case for JEN and United Energy, which applied what the AER considered to be a circular interpretation of clause 3.3. The AER judged this interpretation as circular because:

- it involved first calculating an initial MED threshold as an input into the process to calculate the final MED threshold
- the data to which the MED threshold had been applied was then used as the basis for recalculating it again.

This approach to the calculation, resulted in a MED threshold lower than would be the case if the calculation was applied as intended.[94]

The AER considered that JEN's and United Energy's interpretation of the calculation methodology for the MED threshold was counterintuitive. The AER stated that this interpretation undermined the incentives intended by the MED threshold. The AER considered that applying this literal interpretation was inconsistent with the AER's obligation to perform its regulatory functions in a manner which contributes to the achievement of the NEO.[95]

For these reasons the AER removed the effect of applying the exclusions in clause 3.3(b) of the STPIS as an input into the calculation of the MED boundary threshold from JEN's and United Energy's MED threshold calculation.

15.6.3.2 Victorian DNSP revised regulatory proposals

In its revised regulatory proposal, JEN stated that the AER's interpretation of the MED threshold and step 1 of appendix D of the STPIS is in conflict with the drafting of the STPIS. JEN contended that the STPIS clearly states that any exclusions permitted under clause 3.3 and 5.4 of the STPIS are reflected in the MED boundary calculation.

JEN stated that it believes it understands the AER's interpretation and generally supports the underlying purpose of the STPIS. JEN stated that there is an inconsistency between the intent of the STPIS and the text of the scheme which could be easily rectified by amending references in the text from clause 3.3 to clause 3.3(a), in relation to MED threshold calculations. In the absence of any amendment to the STPIS to this effect, JEN contended that its literal interpretation of the current scheme is correct and should be adopted.

In addressing the calculation of MED thresholds under the STPIS, United Energy did not comment specifically on the issue of the interaction between annexure D and clause 3.3 of the scheme.

[94] AER, *Draft decision*, p. 656.
[95] ibid, p. 657.

15.6.3.3 Issues and AER considerations

As explained in the draft decision, JEN's interpretation of the process to determine the MED threshold is not reflective of the intention of the STPIS. JEN's process is to first calculate a 'first-cut' MED threshold and then apply this 'first-cut' threshold to exclude the major event days as intended by the STPIS. However, JEN then recalculates another MED threshold after the first lot of major event days have been excluded. This process could potentially be repeated again depending on whether more days fit into the 'second-round' MED threshold.

The AER considers that the MED threshold was already determined by the 'first-cut' calculation and hence, the 'first-cut' MED threshold is the actual threshold.

The AER accepts that the construction of clause 3.3 could be improved to provide clarity. Notwithstanding the drafting, the AER notes that CitiPower, Powercor, SP AusNet, and DNSPs in South Australia and Queensland have all interpreted and applied the MED threshold in the manner intended by the AER.

Regardless of any ambiguity surrounding the interpretation of clause 3.3 of the STPIS, section 6.12.1(9) of the NER empowers the AER to make decisions as to how any applicable STPIS is to apply to a DNSP. Section 16 of the NEL guides this discretion, and requires that the AER exercise its powers or functions in a way which will, or is likely to, contribute to the achievement of the NEO. Section 16 also requires the AER to exercise its powers or functions in a way which takes into account the revenue and pricing principles contained in section 7A of the NEL.

Clause 1.5 of the STPIS states that one of the AER's objectives in developing and implementing the scheme is to take into account the 'need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels.'

The role of the STPIS is to provide incentives for DNSPs to maintain and improve service performance as set out in clause 6.6.2(a) of the NER. The STPIS is therefore designed to encourage sustainable improvements to service rather than focusing on one-off infrequent events. Consistent with this, the purpose of specifying a MED threshold at 2.5 beta above mean, or higher if approved by the AER, is to limit the risk that single, very large events—which are outside the control of a DNSP—result in unreasonable penalties being applied.

The MED threshold calculation method proposed by JEN will result in an exclusion threshold lower than 2.5 beta from mean. Appendix D of the STPIS states that 'the 2.5 beta method is the minimum or "safe harbour" approach to setting the major event day boundary that a DNSP may propose'. As such, the MED threshold calculated by JEN will potentially lead to the exclusion of events which the STPIS did not intend to exclude. Therefore, it is inconsistent with the design of the STPIS, as acknowledged by JEN's revised regulatory proposal, and undermines incentive properties of the scheme.

The AER considers that such a result would not contribute to the achievement of the NEO. Specifically, if the MED threshold is lowered by an erroneous application of the calculation method, the strength of the incentive to maintain services standards will be diluted. A lack of sufficient incentive may result in reduced service standards and reliability of electricity supply to consumers.

15.6.3.4 AER conclusion

The AER will apply the STPIS in a manner that will remove the erroneous circular effect of applying the exclusions at clause 3.3(b) as an input into the calculation of the MED boundary threshold to all the Victorian DNSPs for the 2011–15 regulatory control period.

For the first year of the 2011–15 regulatory control period, the MED threshold for each of the Victorian DNSPs is set out in table 15.8.

Table 15.8 AER conclusion—MED threshold (SAIDI minutes)

DNSP	AER conclusion—MED Threshold
CitiPower	1.28
Powercor	9.50
JEN	7.04
SP AusNet	20.08
United Energy	4.75

15.6.4 Adjustments to performance targets for climate change

15.6.4.1 AER draft decision

Based on reports by AECOM, JEN, SP AusNet and United Energy sought adjustments to a number of their reliability targets on the grounds that the number of hot days (above 35^{o}C) and strong-wind days (more than 77 kph) in the 2011–15 regulatory control period are expected to be higher than the average of the 2006–10 regulatory period.[96]

While the AER does not disagree that the climatic conditions in Victoria may be changing as predicted in the reports, it had the following concerns:

- The predictions contained in AECOM's reports may not be relevant to the performance targets set under the STPIS because AECOM's predictions relate to changes from the 1981–2000 long term averages, rather than the averages of 2005–09, on which the STPIS targets are based.
- The annual maximum temperature anomaly in Victoria shown in AECOM's reports shows that the actual maximum temperature for the 2004–08 period was significantly above the long term trend (as shown in figure 15.4).

96 United Energy also claimed that load forecast error and probabilistic planning, and the recent drought would impact on its performance.

- In 2008, the actual number of extreme heat days was higher than the projected number for 2015.

- No specific analysis was provided by the DNSPs for the actual extreme heat days for 2005–09.

- AECOM's studies found that three of the four models used by AECOM did not predict significant change in extreme wind gusts compared to the long term average. As such, the AER was not confident that AECOM's prediction is accurate.

Based on the above concerns, the AER concluded that insufficient evidence was presented to justify adjustments to the performance targets.

15.6.4.2 Victorian DNSP revised regulatory proposals

JEN incorporated the AER's draft decision in its revised regulatory proposal. However, it expressed concerns about the impact of climate change and sought further capex over the 2011–15 regulatory control period. The capex and opex allowances related to the impact of climate change are discussed further in section 8.6.3 and section 7.1.1 of this final decision.

SP AusNet submitted that the AER's conclusion that insufficient evidence was presented to justify adjustments to the performance target was incorrect. SP AusNet stated that:

> the SP AusNet model submitted in support of the adjustment calculation explicitly addressed:
>
> - the annual maximum temperature anomaly in Victoria and the fact that in 2008, the actual number of extreme heat days was less than the projected number for 2015;
>
> - specific analysis by SP AusNet for the actual extreme heat days for 2004–08; and
>
> - specific analysis by SP AusNet for the actual extreme wind days for 2004–08.
>
> This appears to indicate the AER has misunderstood the analysis presented to them and has made a consequential error of fact. Therefore, SP AusNet has resubmitted its climate change adjustment model and organise [sic] a face to face meeting to explain the analysis and calculation set out in the model. This should demonstrate that many of the AER concerns with respect to climate change analysis and the use of AECOM predictions have been addressed. An update for actual 2009 data is also provided as it was not available at the time of submission of the Original Proposal. However, it does not materially change SP AusNet’s forecast of the effects of climate change.[97]

[97] SP AusNet, *Revised regulatory proposal*, p. 46.

CitiPower, Powercor and United Energy did not comment on this matter and accepted the performance targets calculated by the AER.[98]

15.6.4.3 Submissions

The AER did not receive submissions on this matter.

15.6.4.4 Issues and AER considerations

Following the submission of its revised regulatory proposal, SP AusNet clarified that its proposed adjustments were based on observed record of Scoresby weather station, which is different from the reference weather station (Melbourne Airport) used in AECOM's reports. SP AusNet provided an additional comparison for the observed events at Melbourne Airport compared with AECOM's reports forecast, as shown in table 15.9.[99]

The AER did not accept JEN's, SP AusNet's and United Energy's initial regulatory proposals to adjust the STPIS targets because it considered that there was insufficient evidence to support the argument that the average number of hot and strong wind days in the 2011–15 regulatory control period would be greater than the 2006–10 regulatory period.

SP AusNet's revised regulatory proposal followed the argument that the historical averages for hot and strong-wind days over the 2005–09 period, which the STPIS targets are based on, are lower than the numbers forecast by AECOM. Hence, the STPIS targets should be adjusted accordingly.

Table 15.9 Number of hot and strong-wind days at Melbourne Airport compared with AECOM report forecast, 2005–09

Year	2005	2006	2007	2008	2009	Average 2005–09	AECOM forecast 2011–15	Increase Per Year
Number of days above 35°C	6	10	10	9	14	9.8	11.8	2.0
Number of days with 77 - 90kph wind	18	12	16	9	8	12.6	19.5	6.9
Number of days with above 90kph wind	7	5	4	4	2	4.4	6.6	2.2

Source: SP AusNet

Adjustment for more hot days

While the AER does not disagree that the climatic conditions in Victoria may be changing as predicted in AECOM's reports, it still does not consider that adjustments to the STPIS targets are necessary for the 2011–15 regulatory control period for the following reasons:

[98] CitiPower, *Revised regulatory proposal*, p. 396; Powercor, *Revised regulatory proposal*, p. 394; United Energy, *Revised regulatory proposal*, p. 283.

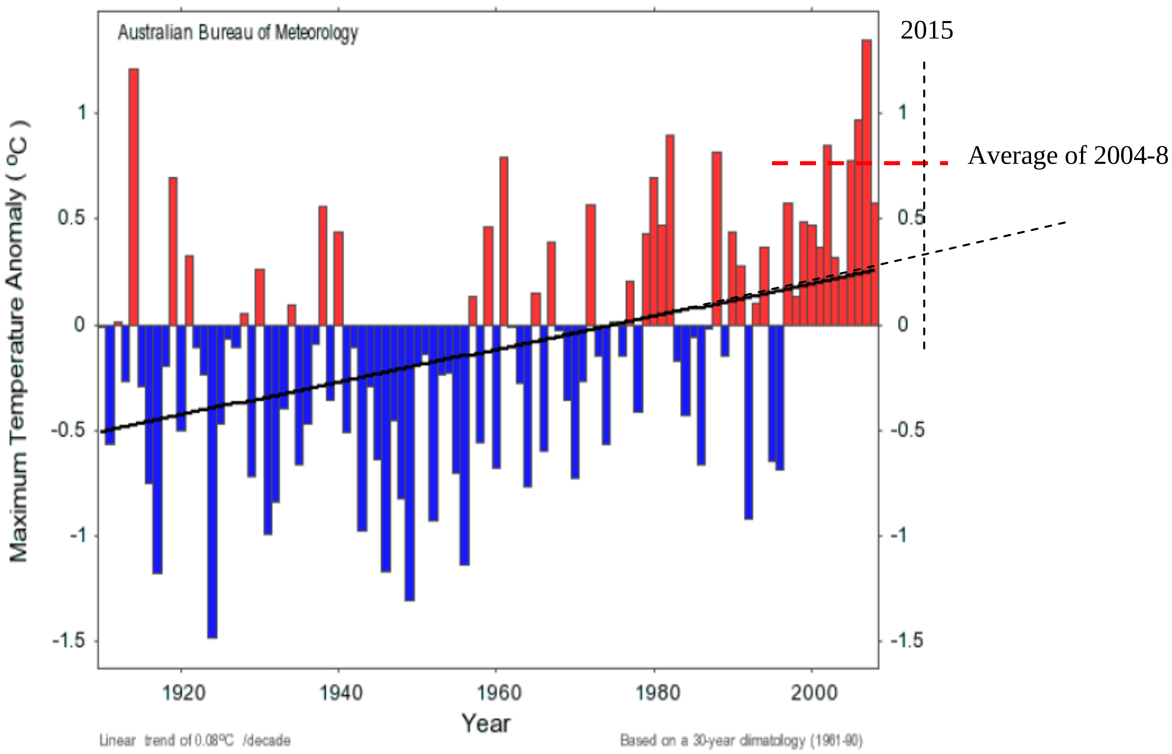
[99] SP AusNet, *email*, 24 August 2010.

- SP AusNet's proposed adjustment was based on the assumption that the average number of hot days (above 35^{o}C) during the 2011–15 regulatory control period is the same as that predicted for 2015 in the AECOM reports. Given that climate change is a progressive process, the average over this period should be less than that predicted for the end of the period. Hence, the assumption contains an error of fact.

- Given that the annual maximum temperature anomaly in Victoria shown in AECOM's reports indicates that the actual maximum temperature for the 2004–08 period was significantly above the long term trend (figure 15.4), the certainty that the 2011–15 regulatory control period would be hotter than the 2006–10 regulatory period remains questionable.

- Irrespective of the above concerns, SP AusNet's opex allowance for the 2011–15 regulatory control period is based on the 2009 reference year, which had more hot days (14 days) than that forecast by AECOM for 2015 (11.8 days). Hence, SP AusNet has adequate opex allowance to maintain the existing level of supply reliability for the 2011–15 regulatory control period.[100]

Figure 15.4 Annual maximum temperature anomaly—Victoria



Source: Australian Bureau of Meteorology, the AER has extended the trend line and added the average from 2004–08

Adjustment for more strong-wind days

The AER still does not consider that an adjustment to the STPIS targets is necessary for the 2011–15 regulatory control period for the following reasons:

100 The AECOM report (page vi) also indicates that the projected supply restoration and reliability costs for SP AusNet for each of the 2011–15 years are lower than that of the reference year.

- AECOM's studies found that three of the four models used by AECOM did not predict significant change in extreme wind gusts compared to the long term average—as such, the AER is not confident that AECOM's prediction is accurate.
- table 15.9 shows that the actual number of strong-wind days was progressively decreasing during the 2005–09 period, from seven to two days. This supports the above concern that there is insufficient evidence to prove that the number of strong-wind days will increase during the 2011–15 regulatory control period.

15.6.4.5 AER conclusion

The AER concludes that there is insufficient evidence to support the claim that the performance targets under clause 3.2.1 of the STPIS should be amended to include an adjustment for the predictions in AECOM's reports on hot and strong-wind days.

The AER also concludes that, in accordance with section 8.6.3 and section 7.1.1 of this decision, the capex and opex allowances provided for each Victorian DNSP, in this final decision, include sufficient expenditure to maintain network reliability. The conclusion not to amend the STPIS targets in response to these projects is consistent with the AER's assessment of, and decision on the Victorian DNSPs' proposed opex and capex proposals pursuant to clauses 6.5.6 and 6.5.7 of the NER respectively.

15.6.5 Performance targets

15.6.5.1 AER draft decision

In its draft decision the AER determined the performance targets for the Victorian DNSPs as set out in table 15.10.

Table 15.10 Draft decision performance targets for SAIDI, SAIFI and MAIFI

	CitiPower	JEN	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI (average minutes)	11.27	–	–	–	–
SAIFI (average interruptions)	0.186	–	–	–	–
MAIFI(average interruptions)	0.026	–	–	–	–
Urban	–	–	–	–	–
SAIDI (average minutes)	22.36	68.50	82.47	105.62	55.09
SAIFI (average interruptions)	0.450	1.127	1.263	1.520	0.899
MAIFI (average interruptions)	0.175	0.776	1.412	2.519	1.074
Rural short	–	–	–	–	–
SAIDI (average minutes)	–	153.15	114.81	214.73	99.15
SAIFI (average interruptions)	–	2.588	1.565	2.697	1.742
MAIFI (average interruptions)	–	1.940	2.881	5.421	2.122
Rural long	–	–	–	–	–
SAIDI (average minutes)	–	–	233.76	267.10	–
SAIFI (average interruptions)	–	–	2.540	3.378	–
MAIFI (average interruptions)	–	–	6.535	8.996	–

Source: AER analysis.

15.6.5.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor, JEN and United Energy all adopted the AER's performance targets in the draft decision.[101]

SP AusNet's revised regulatory proposal sought an adjustment to its performance targets to account for the effects of climate change. As discussed in section 15.6.4, the AER rejected SP AusNet's proposed adjustment to the performance targets to account for the effects of climate change.

SP AusNet's calculation of its performance targets, provided as part of its revised regulatory proposal, differed from that provided to the AER in making the draft decision. The AER notified SP AusNet, which subsequently provided an additional calculation of its STPIS targets. SP AusNet stated that:

101 CitiPower, *Revised regulatory proposal*, p. 396; Powercor, *Revised regulatory proposal*, p. 394; JEN, *Revised regulatory proposal*, p.288; United Energy, *Revised regulatory proposal*, p. 283.

> The submission on the 20 July 2010 had an error that miss allocated performance between feeder classifications this has now been rectified.
>
> It was also noticed that a number of outages that should not have been included in the calculation of targets were included these include outages that were duplicated and outages that resulted in negative USAIDI figures.[102]

United Energy submitted that the AER 'distorted the monthly figures for planned customer minutes off supply…'.[103] It noted that the 2005 and 2006 customer numbers had been changed and that no reason for the change was given. United Energy also noted that the change to customer numbers did not affect the calculation of the performance data. [104]

15.6.5.3 Submissions

EUCV contended that the AER did not assess whether the targets it set for the 2011–15 regulatory control period would result in a net zero outcome if the targets had been applied to the actual performance in the previous five years.[105] It stated that in the AER's draft decision, the proposed inputs and targets in table 15.4 are different to those provided in SP AusNet's regulatory proposal. The EUCV contended that it was difficult to assess how the AER arrived at some of its performance targets.[106]

EUCV submitted that the capex set by the ESCV for the 2006–10 regulatory period was set with the expectation that service performance would improve.[107] The EUCV was concerned that the AER did not require the DNSPs to have service targets that reflect the 2006–10 allowances.[108] The EUCV noted that consumers have paid for consistent increases in capex and opex and there has been little performance improvement in the 2006–10 regulatory period. It also noted that the AER has set targets which do not increase performance, and that this is disappointing.[109]

EUCV submitted that the STPIS targets should be harder than the performance achieved in the past, but that some targets set in the AER's draft decision provide a worse service performance outcome for consumers, especially in the case of JEN's and United Energy's targets.[110]

15.6.5.4 Issues and AER considerations

SP AusNet proposed an adjustment to its performance targets for the effects of climate change on its network. As discussed in section 15.6.4.5 the AER has not agreed to SP AusNet's proposal for a change in its targets.

In relation to SP AusNet's calculation of its performance target, the AER has accepted the performance data, provided on 16 September 2010.[111] The AER has performed the

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102 SP AusNet, *information received on 16 September 2010.*, 16 September 2010.
103 United Energy, *Revised regulatory proposal*, p. 289.
104 ibid., p. 289.
105 EUCV, *Submission to the AER*, 19 August 2010, p. 45.
106 ibid., p. 45.
107 ibid., p. 46.
108 ibid., p. 46.
109 ibid., p. 47.
110 ibid., p. 46.
111 SP AusNet, *information received on 16 September 2010*, 16 September 2010.

calculation of the performance targets using this data and an exclusion threshold of 2.8 beta from the mean.

In relation to the target calculated in the draft decision, United Energy objected to the way in which the AER ‘distorted the monthly figures for planned customer minutes off supply…’.[112] The AER adjusted the monthly customer numbers so that the numbers were in accordance with the STPIS definition, which is that the number of distribution customers is calculated as the average of the number of customer at the beginning of the reporting period and the number of customers at the end of the reporting period. The AER notes that it incorrectly adjusted the 2005 and 2006 monthly customer numbers. These monthly customer numbers did not feed into the calculation of the targets and the correct numbers were used.

EUCV comments regarding targets

EUCV submitted on a number of issues relating to the STPIS targets. The manner in which the performance targets are calculated is specified in the STPIS. The targets are consistent with the capex and opex allowances for the 2011–15 regulatory period approved in sections 8.6.3 and 7.1.1. These capex and opex allowances provide for the maintenance of reliability levels over the 2011–15 regulatory control period. The AER considers that changes in service performance in the 2006–10 regulatory period have been appropriately rewarded or penalised under the ESCV S factor scheme. Further, any changes in service performance in the 2011–15 regulatory control period will be rewarded or penalised under the STPIS.

The AER intends to continue to publish DNSPs’ actual performance relative to their respective performance targets for the 2011–15 regulatory control period.

15.6.5.5 AER conclusion

Table 15.11 sets out the AER's final decision on the performance targets to apply to the Victorian DNSPs in the 2011–15 regulatory control period. For accuracy, all performance targets are specified to three decimal places.

The AER has adjusted SP AusNet's MAIFI target down by the amounts outlined in table 15.14 for the 2011–15 regulatory control period. In making this MAIFI adjustment, the AER has had regard to the past performance of SP AusNet's network.

112 United Energy, *Revised regulatory proposal*, p. 289.

Table 15.11 AER conclusion on performance targets for SAIDI, SAIFI and MAIFI

	CitiPower	JEN	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI (average minutes)	11.271	–	–	–	–
SAIFI (average interruptions)	0.186	–	–	–	–
MAIFI(average interruptions)	0.026	–	–	–	–
Urban	–	–	–	–	–
SAIDI (average minutes)	22.360	68.498	82.467	101.803	55.085
SAIFI(average interruptions)	0.450	1.127	1.263	1.448	0.899
MAIFI(average interruptions)	0.175	0.776	1.412	2.512	1.074
Rural short	–	–	–	–	–
SAIDI (average minutes)	–	153.150	114.807	208.542	99.151
SAIFI(average interruptions)	–	2.588	1.565	2.632	1.742
MAIFI(average interruptions)	–	1.940	2.881	5.409	2.122
Rural long	–	–	–	–	–
SAIDI (average minutes)	–	–	233.759	256.578	–
SAIFI(average interruptions)	–	–	2.540	3.317	–
MAIFI(average interruptions)	–	–	6.535	8.924	–

15.6.6 Close out of the ESCV S factor scheme

The ESCV S factor scheme is an incentive scheme designed to deliver financial rewards or penalties to Victorian DNSPs for improvements or deteriorations in service performance. In its 2001 EPDR, the former Office of the Regulator General (ORG) stated that the aims of the scheme were:

> the incentives should be specified clearly and in advance, to maximise their effectiveness
>
> the scheme should be as simple as possible to understand for both distributors and customers, without distorting the incentives
>
> the incentives should be based on reliable and verifiable performance measures, with independent scrutiny of the distributors' measurement of their performance
>
> the incentives should address worst-case performance as well as average performance, to ensure that benefits flow to all customers

the incentives should encompass both penalties for under-performance and rewards for superior performance

the amount of revenue that distributors stand to gain or lose under the incentives should be limited, but large enough to provide meaningful commercial incentives at the margin. The amount of the incentives should be greater than the cost to distributors of achieving an increment of reliability, but less than the value that customers place on that increment of reliability

there should be no exclusions for external events, such as severe storms or load shedding due to a shortfall in generation capacity. Such risks are better allocated to distributors than customers, given that distributors have a greater capacity to mitigate their impact

where incentive payments are to be paid directly to specific customers for specific events, the scheme should provide for automatic payments rather than payment on application by the customer

customers should retain any right they currently have to seek additional compensation for specific losses caused by supply interruptions.[113]

The ESCV S factor scheme will cease to operate at the end of the 2006–10 regulatory period and will be replaced by the STPIS. The design and construction of the ESCV S factor scheme is such that the accrued financial outcomes of actual service performance in a particular year are lagged by two years and then have a continuing effect for six years. Hence, the financial impact on a DNSP resulting from the ESCV S factor scheme, for its actual performance in the 2010 calendar year, would not be fully realised until 2018. In ceasing the ESCV S factor scheme from operating (closing it out) consideration needs to be given to the effects of both the two year lag and the continuing effects of the ESCV S factor scheme.

The AER considers it appropriate to apply a close out methodology that gives effect to the intended benefits, or penalties, of the ESCV S factor scheme. This ensures that if a DNSP has accrued a financial benefit, due to improved performance in the 2006–10 regulatory period, then the DNSP is entitled to receive the benefit as per the construction of the scheme. Conversely, where a DNSP has accrued a financial penalty, due to reduced supply reliability in the 2006–10 regulatory period, then customers are entitled to have this reflected in lower prices, as was intended under the ESCV S factor scheme. This approach would also give effect to the expected outcomes that the Victorian DNSPs could have reasonably expected at the time they made operational and investment decisions during the 2006–10 regulatory period. In adopting this approach, the AER also considers that it is providing the Victorian DNSPs regulatory certainty for the investment and operational decisions made over the 2006–10 regulatory period.

Therefore, the AER considers that closing out the ESCV S factor scheme, by replicating the intended benefits or penalties of the ESCV S factor scheme, is consistent with the NEO. That is, it promotes efficient investment in, and efficient operation and use of, electricity services in the long term interests of consumers, by promoting regulatory certainty. In considering the most appropriate way to close out

[113] ESCV, *Electricity Distribution Price Determination 2001–05 Volume I Statement of Purpose and Reasons*, p. 19.

the scheme, the AER has also taken into account the revenue and pricing principles, specifically subsection (3) which states that a network service provider should be provided with effective incentives to promote economic efficiency.

As the ESCV applied its S factor scheme to all Victorian DNSPs in a consistent manner, the AER considers it appropriate to apply a consistent methodology to close out the scheme for all Victorian DNSPs.

Regulatory requirements

Clause 6.4.3(a)(5) of the NER states that the annual revenue requirement for a DNSP for each regulatory year of a regulatory control period must be determined using the building blocks, which include the revenue increment or decrements that may arise as a result of the operation of the applicable STPIS.

Clause 6.3.2(a)(3) of the NER requires that a building block determination is to specify for a regulatory control period how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme are to apply to the DNSP.

The AER released its initial STPIS in June 2008 in accordance with clause 6.6.2(a) of the NER. In the AER's Final decision on its June 2008 STPIS, the AER recognised that there may be transitional issues which arise in moving from a jurisdictional service incentive scheme to the AER's STPIS. It stated that:

> The AER recognises that there may be other transitional issues which arise in moving to the national scheme and also from one regulatory control period to the next. These transitional issues cannot be foreseen with certainty. Accordingly, the STPIS includes an arrangement that reduces the impact of transitional issues and the AER will address such issues as they arise during the framework and approach and distribution determination processes.

Following through on this statement, the AER's Framework and approach paper for the Victorian DNSPs sought to minimise the regulatory uncertainty that could arise when transitioning from one regulatory framework to another.[114] In relation to closing out the ESCV S factor scheme, the AER provided the following guidance in its Framework and approach paper:

> the AER will carryover any adjustments arising from the EDPR, for example in relation to “L” and “S” factor adjustments, that will impact in the 2011–15 regulatory period. These adjustments will be addressed through the revenue building block approach in accordance with chapter 6, Part C of the NER[115]

SP AusNet provided a submission on the AER's draft Framework and approach paper concerning the interaction between the ESCV S factor scheme and the STPIS. In response, the AER stated:

> …the AER notes that benefits and penalties accrued in the current regulatory control period under the ESCV scheme will not be incorporated in the price cap formula. Rather, financial carryover amounts from the

[114] AER, *Framework and approach*, May 2009, p. 15.
[115] AER, *Framework and approach*, May 2009, p. 75.

> current regulatory control period will be included as a building block element in the calculation of allowed revenue for the next regulatory control period.[116]

15.6.6.1 AER draft decision

After considering the approaches put forward by all Victorian DNSPs, the AER proposed the following methodology to close out the ESCV S factor scheme in its draft decision:

1. The DNSPs' reliability performance for 2010 is estimated as the actual performance will not be known until part way through 2011. The AER considers that an appropriate estimation methodology to use is the average performance over the past five years (2005–09).
2. S”t is calculated for 2009 and 2010 in accordance with the ESCV S factor scheme.
3. S’t for 2011 and 2012 is calculated by banking S”t in accordance with the DNSPs' stated intentions. The WACC to apply in the banking calculation is the 2006–10 EDPR WACC.
4. S’t for 2013–18 is held constant at 0.
5. St is calculated for 2010–18 in accordance with the ESCV S factor scheme. The AER notes that St and S't-6 become zero after 2018 and at this time the effects of the ESCV S factor scheme have been fully accounted for.
6. The estimates of forecast revenue are to be the approved 2010 tariff prices multiplied by the demand forecast. For the years 2016–18, forecast revenues are to be held constant at 2015 levels.
7. The S factor is applied to the forecast revenues for 2011–18. For 2011–15, the difference between the estimates of tariff revenues, excluding and including the S factor is then factored into the building blocks.
8. The difference between the estimates of tariff revenues, excluding and including the S factor, for 2016–18 are converted to 2015 values in net present value terms and applied to the building blocks in 2015. The WACC to apply to this NPV calculation is the 2011–15 EDPR WACC.

15.6.6.2 Victorian DNSP revised regulatory proposals

CitiPower's and Powercor's revised regulatory proposals proposed the same solution to the close out of the ESCV S factor scheme as in their initial regulatory proposals. CitiPower and Powercor challenged the AER's draft decision calculation of 2011 performance, stating that:

> …to properly close out the S factor scheme, the calculation must include the calculation of the revenue increments or decrements arising from the incremental change in service performance between the STPIS targets for 2011 and performance in 2010. Since the 2011 STPIS targets are proposed to be based on average actual service performance over 2005–09, the 2011 STPIS targets for the purpose of the S factor true up calculation are proposed to be based on actual average service performance over 2005–09, applying the current regulatory control period exclusion criteria.

[116] ibid., p. 94.

In support of their revised proposals, CitiPower and Powercor submitted a report from Price Waterhouse Coopers (PWC) which found that:

> …the AER has not correctly quantified the value of the future increment or decrement to revenue for performance in 2010 that would have resulted from a continuation of the ESCV scheme.[117]
>
> The combination of the AER's method for quantifying the value of the future increment or decrement to revenue for performance in 2010 together with its approach for setting the new performance targets means that only the first of these components has been taken into accounted. This implies that:
>
> - if 2010 turns out to be a 'randomly bad' year, then the penalty for 2010 performance will be much larger than intended under the ESCV scheme; whereas
>
> - if 2010 turns out to be a 'randomly good year', then the reward for 2010 performance will be much larger than intended under the ESCV scheme.[118]

However, the PWC report also stated that:

> …with the exception of the important omission discussed above [using 2010 performance as the estimate for ongoing performance] I agree with the AER's quantification of the value of the future increments or decrements to distribution business revenue that would have occurred as a result of service performance in the 2006-2010 regulatory period[119]

PWC proposed some possible remedies to the issues it identified with the AER's draft decision:

> One remedy would be to set the new performance targets under the AER scheme at the level of outturn performance in 2010 (while this would not be known until after the end of 2010, it will not be required until after that time either). This would create approximately the same payoffs in respect of 2010 performance as would have occurred under a continuation of the ESCV scheme (a correction would be required to replicate the ESCV payoffs exactly).
>
> A second remedy would be to reapply the ESCV scheme again for 2011 on the assumption that performance in 2011 returns to the new target. The AER scheme would then be applied simultaneously to reward or penalise any difference between the new target performance and the actual level.
>
> At first sight, a third remedy would appear to be to apply the penalty or reward in respect of 2010 performance that would be calculated under the ESCV scheme for a single year rather than applying it for the six years that would be the case under the ESCV scheme. However, this remedy is only approximately correct if performance in 2009 was at the underlying level, which cannot be assumed (and, for Powercor, I understand this clearly was not the case).
>
> Out of these, I would advocate the second remedy as it most closely replicates the payoffs that would have occurred under the ESCV scheme, is

117 PricewaterhouseCoopers, *S factor close out*, p. 2.
118 ibid,. p. 3.
119 ibid,. p. 3.

> computationally the simplest and avoids having to change the performance targets from those already foreshadowed for the 2011-2015 regulatory period.[120]

In its revised regulatory proposal United Energy stated that:

> The AER's Draft Decision sets out a method for closing out the ESCV S-factor scheme. The choice of method was not discussed with UED prior to the release of the Draft Decision. The Draft Decision imposed a cumulative penalty on UED of $102 million, which is an unprecedented penalty for service performance. The level of the penalty is particularly staggering given that the AER has not criticised or warned UED in relation to its service performance. The AER's $102 million penalty contrasts sharply with the $2 million penalty calculated by UED, using exactly the same performance data.
>
> The fundamental problem with the AER's close out arrangement is that any attempt to mathematically close out the scheme undermines the basic design principles and incentive properties.
>
> As a consequence of the S-factor design, any attempts to close out the scheme will deliver spurious and unintended outcomes such as those calculated by the AER in its Draft Decision. UED has previously highlighted a number of peculiar features inherent in the ESCV's S-factor scheme, which have the potential to create unintended and illogical outcomes…[121]
>
> The nature of the ESCV's S-factor scheme means that any close out mechanism will contain arbitrary assumptions that cause random penalty or bonus payments that cannot be justified by reference to the original design features of the S-factor scheme. UED therefore does not favour a mathematical solution to the close out mechanism. UED's view is that the scheme should simply not proceed from 31 December 2010 and that no close out amount should be included in the building blocks for the forthcoming regulatory period.[122]

JEN stated that:

> JEN has incorporated the AER's draft decision for S factor true-up within the building block cost of services…[123]

SP AusNet accepted the AER's methodology for closing out the ESCV S factor scheme specified in its draft decision.[124]

15.6.6.3 Submissions

Due to the divergence of opinion on this matter and the further material presented to the AER in the revised regulatory proposals, the AER undertook further consultation with the Victorian DNSPs and those parties who provided a submission on the AER's draft decision. Specifically, the AER called for submissions on CitiPower's and Powercor's proposed method for closing out the ESCV S factor scheme and the appropriate estimate for 2011 performance if CitiPower's and Powercor's

120 ibid., p. 4.
121 United Energy, *Revised regulatory proposal*, p. 217.
122 ibid., p. 220.
123 JEN, *Revised regulatory proposal*, p. 286.
124 SP AusNet, *Revised regulatory proposal*, p. 52.

methodology was adopted for all Victorian DNSPs.[125] In response, the AER received further submissions from CitiPower, Powercor, SP AusNet and United Energy.

In its further submission, SP AusNet stated that:

> SP AusNet would reiterate that it has accepted and would continue to support the manner of the payout of the S factor scheme as proposed by the AER in the Draft Decision. The major positive of the draft decision approach is that the negative effects of the 2009 bushfires on the reliability payments to SP AusNet are muted under this approach regardless of the 2010 reliability outcomes (NPV less than $10M).
>
> However, if the alternative approach proposed by Powercor/Citipower was adopted, SP AusNet believes the potential negative NPV effects of the bushfire rise to as much as $30M.

Further, SP AusNet did not consider that the close out approach proposed by Powercor and CitiPower in their revised regulatory proposals to be correct as it:

> …does not capture all the ongoing effects of the 2010 performance and, therefore, does not return the scheme to a neutral position. The proposed close out mechanism considers only the effects of the 2010 performance on the S factor scheme itself. However, the 2010 performance affects not only the payout of the ESC S factor scheme but also the payout of the AER STPIS. This is because the 2010-2014 performance will be used to set targets for the 2016-20 regulatory control period. Thus, 2010 performance has ongoing effects well into the second regulatory control period of the STPIS scheme.[126]

United Energy submitted that:

> The ESCV’s S-factor scheme and the AER’s STPIS are different schemes, and it is not correct to view the STPIS as modifying or changing the ESCV’s S-factor scheme.
>
> … it is important to keep in mind that the ESCV’s scheme is not continuing — it will cease on 31 December 2010 and will be replaced by the AER’s STPIS on 1 January 2011. UED does not accept the proposition that the AER’s close out calculation should seek to replicate the payments that would have been made if the ESCV’s scheme were to continue.
>
> It should also be emphasised that the ESCV’s scheme does not provide for assumptions to be made regarding future network performance, i.e. performance in the 2011 calendar year. It is therefore highly questionable whether the proposed remedy suggested by PricewaterhouseCoopers could be regarded as giving effect to the ESCV’s scheme.
>
> UED recognises that ceasing the ESCV’s S-factor scheme on 31 December 2010 will result in the scheme not rewarding or penalising network performance for 2009 and 2010 (because the S-factor scheme applies 2 years in arrears)… From a regulatory perspective this does not have a material adverse effect on incentives because the affected years are complete (in the case of 2009) or largely complete (in the case of 2010).

[125] AER, *email*, 31 August 2010.
[126] SPA, *email*, 10 September 2010.

> …UED considers that attempt to continue the ESCV's S-factor scheme beyond 2010 is bound to lead to anomalous outcomes because it requires assumptions to be made regarding underlying network performance in 2011, as suggested by PricewaterhouseCoopers, is not part of the ESCV's S-factor scheme and must not be used as part of the close out calculation.[127]

CitiPower and Powercor provided a submission illustrating why they considered 2005–09 performance is the appropriate average to use in setting the estimate of 2011 performance. CitiPower and Powercor considered that 2005–09 performance is the appropriate average because it closely approximates the intended rewards or penalties that would arise under the ESCV S factor scheme.[128]

15.6.6.4 Issues and AER considerations

Consistent with the AER's Framework and approach paper, and the methodology adopted in section 15.7.12 of its draft decision, the AER will apply the benefits and penalties accrued in the 2006–10 regulatory period under the ESCV S factor scheme as a building block element in the calculation of allowed revenue for the 2011–15 regulatory control period. Following feedback on the methodology specified in its draft decision, the AER has changed its methodology for estimating the 2011 and ongoing performance. Consideration of this change is set out below.

The AER notes that there are essentially three approaches nominated by the Victorian DNSPs to close out the ESCV S factor scheme:

- terminate the scheme after 2010, after taking into consideration the actual performance of 2008, but without applying any subsequent years' impact on the S factor values
- terminate the scheme after 2012, after taking into consideration the actual performance of 2010 (the final year of the ESCV scheme), but without applying any subsequent years' impact on the S factor values
- apply all accrued benefits and penalties for each year's performance for six years as required by the ESCV scheme. This requires a constant estimate of the underlying performance of the DNSPs from 2011 onwards.

These three approaches are analysed below.

Discontinue the ESCV scheme after 2010

United Energy contended that there is no objectively correct mechanism for closing out the ESCV S factor scheme, and that the scheme should simply not proceed from 31 December 2010.[129]

United Energy's proposal results in the S factor scheme not rewarding or penalising actual network performance which occurred in 2009 and 2010, because there is a two year lag before the S factor impacts on the price control formula. Further, the benefits,

[127] United Energy, *email*, 15 September 2010.
[128] CitiPower, *email*, 10 September 2010; Powercor, *email*, 10 September 2010
[129] United Energy, *Revised regulatory proposal*, p. 218.

or penalties, accrued in respect of performance in 2006, 2007 and 2008 would not be incurred for the intended six year period.[130]

United Energy contended this does not materially impact the incentives of the scheme because 2009 and 2010 are largely complete. Therefore, the Victorian DNSPs have behaved as though the scheme would apply.

The AER considers that it is inappropriate that accrued rewards, or penalties, due to service performance in 2009 and 2010 would not flow through to a DNSP's revenue and customer tariffs. If a DNSP has accrued a financial benefit, due to improved performance in the 2006–10 regulatory period, then the DNSP is entitled to receive this benefit. Conversely where a DNSP has accrued a financial penalty, due to reduced supply reliability in the 2006–10 regulatory period, then customers are entitled to have this reflected in lower prices, as was intended under the ESCV S factor scheme.

United Energy's proposed method of stopping the S factor scheme will materially alter the financial outcome of the scheme, both from that intended by the ESCV and that which could have reasonably been expected by the Victorian DNSPs during the 2006–10 regulatory period.

Victorian DNSPs have been subject to the incentive properties of the ESCV S factor scheme, and it is reasonable to expect that they made investment and operational decisions taking into account this incentive regime. Under United Energy's proposal, the outcomes from this incentive scheme that could have been reasonably anticipated during the 2006–10 regulatory period, will not eventuate. Therefore, the AER considers that United Energy's proposal is inconsistent with the original design principles, as it does not give effect to the incentives of the scheme that were specified clearly and in advance. The AER also considers that United Energy's proposal does not provide regulatory certainty and that this is not consistent with the NEO—as it does not promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers. Further, the AER considers it to be inconsistent with the revenue and pricing principles—as it does not provide an effective incentive to promote economic efficiency with respect to direct control network services.

United Energy also contended that any close out which relies upon an assumption of future performance will be arbitrary in its outcome. United Energy also believes that the ESCV S factor scheme does not provide for assumptions to be made regarding future network performance, and that it is therefore highly questionably whether the proposed remedy could be regarded as giving effect to the ESCV S factor scheme.[131]

The AER considers that using an estimate of future performance, based on actual historical performance, represents a reasonable and necessary inclusion in the close out methodology. The AER also considers that adopting an estimate of 2011 performance to close out the scheme is appropriate, as the AER's analysis indicates that this method more accurately replicates the expected financial outcome of the

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130 The ESCV S factor scheme was designed such that 'the reward or penalty for a particular year should continue for six years rather than five, to better match the profile of costs or savings under the efficiency carryover.'

131 United Energy, *response to information request*, 10 September p. 6.

ESCV S factor scheme than United Energy's proposal to ignore performance in 2009 and 2010. Therefore, the AER does not consider the outcome of its approach to be arbitrary. The AER's conclusion on the methodology to estimate performance for 2011 onwards is set out later in this section.

Discontinue the ESCV scheme after 2012

SP AusNet proposed that all benefits and penalties should cease to be paid after 2012. That is, the 2010 performance would impact on revenue for one year (in 2012) and all the repeating payments flowing from 2010 and earlier years would not impact on revenue.

SP AusNet presented modelling to support its claim that its methodology appropriately closes out the ESCV S factor scheme. The AER has examined SP AusNet's modelling and considers that the model relies on several simplifying assumptions. In particular, the modelling does not properly account for the manner in which S factors are calculated from the raw performance data, and then converted into a cumulative S factor, pursuant to the ESCV scheme. The modelling presented by SP AusNet assumes that particularly good, or bad, performance in one year is perfectly offset by a return to underlying performance. This is not the case with the ESCV S factor scheme and the implications of this have previously been considered by the ESCV.[132] The AER considers that, if these corrections are made to SP AusNet's modelling to make it consistent with the ESCV S factor scheme, SP AusNet's proposed methodology does not adequately replicate the benefits or penalties of the ESCV S factor scheme, as claimed by SP AusNet.

Additionally, the ESCV S factor scheme was designed such that 'the reward, or penalty, for a particular year should continue for six years rather than five, to better match the profile of costs or savings under the efficiency carryover'.[133] As such, the AER does not consider it appropriate to stop all increments and decrements from the ESCV S factor scheme after 2012 (as proposed by SP AusNet), as it does not appropriately replicate the benefits and penalties that would have occurred under the ESCV S factor scheme.

As already discussed in relation to stopping all benefits and penalties from 2010 onwards, the AER considers that stopping the payments after 2012 is inconsistent with the NEO and the revenue pricing principles, as it does not give effect to an incentive that was present during the 2006–10 regulatory period. Hence, the AER considers that SP AusNet's proposed approach is not consistent with the objective of promoting economic efficiency with respect to direct control network services.

Estimate of performance from 2011 onwards

After considering all relevant submissions, the AER concludes that the method proposed by CitiPower and Powercor in their revised regulatory proposals appropriately replicates the expected benefits, or penalties, that would have occurred under the ESCV S factor scheme. The practical difference, between this methodology and if the S factor scheme was to continue to operate, is that service performance is assumed to be constant at an average level of performance from 2011 onwards. This assumption replicates important design aspects of the scheme, particularly that

132 ESCV, *2006–10 EDPR Final Decision Vol 1*, p. 93.
133 ESCV, *2001–05 EDPR Vol 1 Statement of Reason and Purpose,* p. 39.

benefits and penalties in respect of a single year's performance, are paid on a recurring basis for a period of six years. This methodology is substantially the same as the methodology presented in the AER's draft decision. However, the AER has reconsidered its position regarding the best estimate of assumed service performance for 2011 onwards.

In its draft decision, the AER considered that 2010 performance should be used as the assumption of 2011 and ongoing performance, on the basis that it is the most up to date estimate of performance available and that there was no guarantee performance will return to trend. The AER now considers that this approach is not the most accurate way of closing out the ESCV S factor scheme. If a DNSP's performance is either randomly good, or bad, in 2010, the calculation methodology for 2011 and ongoing performance in the AER's draft decision will entrench this performance in the calculation of the increments or decrements and a DNSP will be inappropriately rewarded or penalised. The AER now considers that this approach will not give effect to the NEO or be consistent with the revenue and pricing principles.

The AER requested the Victorian DNSPs and those stakeholders who provided a submission in response to the AER's draft decision, to comment on the appropriateness of applying CitiPower's and Powercor's proposed methodology as the basis to close out the ESCV S factor scheme.[134]

CitiPower and Powercor submitted that the best estimate of service performance for 2011 onwards is to use the average of 2005–09 service performance. CitiPower and Powercor believed that their modelling demonstrated that this is the outcome closest to that intended by the ESCV S factor scheme.

In its further submission, SP AusNet disagreed with CitiPower's and Powercor's proposal to use the 2005–09 average performance as an estimate for ongoing performance. SP AusNet submitted that this approach does not close out the scheme to a neutral position as it does not capture all the ongoing effects of the 2010 performance.[135]

The AER tested CitiPower's and Powercor's model and found that their assumption that a particularly good or bad performance in one year is perfectly offset by a return to underlying performance does not result in an outcome that is consistent with the scheme.

In addition, the AER considers that CitiPower's and Powercor's proposed approach to use the average historical performance (2005 to 2009) as a representation of the underlying performance has some merit. However, as their proposed use of an average of 2005–09 performance does not take into account their performance during 2010, this assumption does not give full effect of the ESCV S factor scheme, which ends in 2010.

Having regard to the revised regulatory proposals and further submissions, the AER has concluded that the 2011 and ongoing estimate of performance is most appropriately calculated by using an average of 2005–10 service performance. In

[134] AER, *email*, 31 August 2010.
[135] SP AusNet, *email*, 10 September 2010.

reaching this conclusion the AER had regard to CitiPower's, Powercor's, SP AusNet's and United Energy's submissions. The AER considers that it is appropriate to include 2010 performance in the average measure of performance used to close out the ESCV S factor scheme, as this is the most recent performance information relevant to this scheme. This will assist in ensuring the estimated level of performance accurately reflects expected performance outcomes. Further, as a DNSP's revenue outcomes under the ESCV S factor scheme for actual service performance in the 2006–10 regulatory period are calculated with reference to the years 2005–10, the AER considers it appropriate to use all this performance data in calculating the underlying level of performance.[136] Finally, the analysis undertaken by the AER indicates that, out of the alternative methodologies presented to the AER, using the average of 2005–10 performance as an estimate of ongoing performance closely replicates the intended outcomes of the ESCV S factor scheme.

The AER considers that its chosen methodology and assumptions are consistent with the NEO, and the revenue and pricing principles—as they best give effect to the benefits and penalties that a DNSP would have expected to receive due to its service performance in the 2006–10 regulatory period. This promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers.

Banking methodology

In closing out the ESCV S factor scheme, the Victorian DNSPs have nominated the manner in which to apply $S_{bank,t,}$ for service performance in 2009 and 2010. This has been done in accordance with section 2.3 of the Electricity Distribution Price Review 2006–10 Final Decision Volume 2 Price Determination (2006 EDPR volume 2). The AER applied these banking assumptions provided by the Victorian DNSPs in response to its further consultation on this issue.[137] United Energy did not provide an update on its banking methodology and as such, the AER has applied the same assumption used in its draft decision.[138]

Additional issues

United Energy submitted that the AER’s proposed close out mechanism is inconsistent with three of the original design principles of the ESCV scheme. In response to the AER's draft decision, United Energy stated that:

> - The incentives have not been specified clearly and in advance, to maximise their effectiveness. In fact, the AER’s close out arrangement retrospectively imposes a higher incentive rate in relation to 2010 performance.
>
> - The scheme is not as simple as possible, and cannot be understood by distributors and customers. In fact, the calculation of the close out

136 Calculating the increments and decrements with respect to actual performance in the 2006–10 regulatory period, in accordance with sections 2.3.9 to 2.3.14 of the 2006 EDPR volume 2, requires performance from the years 2005–10. 2005 performance is required as the revenue increments or decrements for 2006 are calculated on the basis of the change from 2005 performance.

137 AER, *email*, 27 September 2010.

138 United Energy's S factor close out model, provided to the AER on 17 February 2010, United Energy's model contained assumptions regarding the manner in which the S factor would be banked. The AER applied these assumptions in both the draft and final decision.

> arrangement is so complex that the AER is evidently unaware of the distorted incentives that it introduces.
>
> - The amount of revenue that distributors stand to gain or lose as a result of performance in 2010 is not consistent with appropriate incentives.[139]

The AER does not consider that there is any element of retrospectivity about its close out method. The AER has attempted to close out the scheme in a manner that best replicates what the financial impact of the scheme would have been, had the scheme continued. In doing so, the AER has attempted to provide the Victorian DNSPs with regulatory certainty by replicating the benefits and penalties that have already accrued to the Victorian DNSPs. As already stated, the AER considers that such regulatory certainty is critical for regulated firms to make both operational and long term investment decisions with confidence and is consistent with the NEO.

The AER recognises that there is a necessary degree of complexity surrounding the close out of the ESCV S factor scheme, and has sought to explain its reasoning in a coherent and transparent manner.

Finally, the AER recognises United Energy's concerns with respect to the AER's use, in its draft decision, of 2010 performance as the estimate of ongoing performance. The AER notes that the estimate of 2011 and ongoing performance has been changed in the final decision.

STPIS exclusion criteria

In response to the AER's request for further submissions, SP AusNet stated that:

> The most suitable 2011 target for SP AusNet [if CitiPower’s and Powercor’s methodology is adopted] is the STPIS targets based on 3.2 beta as this provides the underlying network performance excluding rare events and would be expected to be reflective of SP AusNet’s long term average network performance under the ESC regime. As previously submitted, only 2 events not excluded under the ESC exclusion regime are excluded under the AER regime using a 3.2 beta and these are the Gippsland Floods and the Victorian Bushfires; both are events that have been declared as 1 in 100 year events.[140]

The ESCV S factor scheme and the AER's STPIS have different incentive rates, targets and apply different exclusion criteria when calculating performance. The exclusion criteria for the AER's STPIS is set out in section 3.3 of the STPIS and excludes major event days that exceed a pre determined SAIDI exclusion criteria.

The exclusion criteria under the ESCV S factor scheme are specified in sections 2.3.13 and 2.3.14 of the 2006 EDPR.[141] After 1 January 2005, the ESCV scheme could exclude events on the basis that the daily SAIFI exceeded a threshold set out in the 2006 EDPR. As stated by SP AusNet, there were no exclusions granted, in accordance with the relevant sections of the ESCV S factor scheme, for neither the

139 United Energy, *Revised regulatory proposal*, p. 219.
140 SP AusNet, *email*, 10 September 2010, p. 1.
141 ESCV, *2006–10 EDPR Vol 2* , p. 19

Victorian bushfires nor the Gippsland Floods.[142] The ESCV considered that a SAIFI exclusion threshold was appropriate because:

> In the Commission's view, SAIFI, rather than SAIDI, is a better indicator that a large number of events have occurred which will stretch the distributors' resources to restore supply. Additionally, it is consistent with Ofgem's approach for severe weather events.[143]

The AER considers that the ESCV has specifically turned its mind to using a SAIDI exclusion criteria and that it concluded that a SAIFI exclusion criteria, which it adopted, was the appropriate exclusion criteria to apply in its S factor scheme. As such it would be inappropriate for the AER to apply a SAIDI exclusion criteria in closing out the ESCV S factor scheme.

The STPIS is a new incentive scheme, which differs in its design from the ESCV S factor scheme, and has a different set of exclusion criteria to the ESCV S factor scheme. Hence, to close out the ESCV S factor scheme, SP AusNet's performance prior to 1 January 2011 (the start date for the application of the STPIS) must be measured in accordance with the ESCV S factor scheme. This is consistent with one of the original design principles, 'that the incentives should be set in advance'.[144] The AER considers that the STPIS exclusion criteria are not relevant to the calculation of rewards, or penalties, under the ESCV S factor scheme and, to use the STPIS exclusion criteria would not be consistent with the design of the ESCV S factor scheme.

Further, the AER considers it appropriate to apply the ESCV exclusion criteria to the close out in the interests of regulatory certainty, as the ESCV's exclusion criteria applied during the 2006–10 regulatory period. Therefore, when making investment and operational decisions, the Victorian DNSPs would have reasonably assumed that the ESCV exclusion criteria would apply to the measurement of performance, and hence rewards or penalties under the ESCV S factor scheme.

15.6.6.5 AER conclusion

The AER concludes that the appropriate way to close out the ESCV S factor is to apply the methodology set out in its draft decision with an adjusted calculation methodology for the estimate of 2011 and ongoing performance for all Victorian DNSPs. The AER has reached this conclusion after analysing all relevant submissions, having regard to the NEO, and taking into account the revenue pricing principles and the original design principles of the ESCV S factor scheme.

The AER considers that the appropriate assumption to use for ongoing performance (from 2011 onwards) for the purposes of closing out the ESCV S factor scheme is to set it at the average of 2005–10 performance, applying the exclusion criteria set out in section 2.3.13 (i) of the 2005–10 EDPR. The AER considers this assumption most closely replicates the intention of the ESCV scheme.

The AER considers the appropriate methodology to close out the ESCV S factor scheme is to apply all calculations of the ESCV S factor scheme, as set out in section

[142] SP AusNet, *email*, 10 September 2010, p. 1.
[143] ESCV, *2006–10 EDPR Final Decision Vol 1*, p. 123
[144] ESCV, *2001–05 EDPR Vol 1 Statement of Reason and Purpose*, p. 19.

2.3 of the 2006 EDPR volume 2, for all years from 2011 to 2018 inclusive and to incorporate the financial outcomes into the building blocks.

In order to implement the close out methodology in this final decision, the key change from the draft decision is to hold $ACT_{t-2}^{r,n}$, in the S factor calculation, constant and equal to the average of 2005–10 performance for t = 2013 onwards.[145]

The AER has provided the Victorian DNSPs with a spreadsheet calculating the building blocks that will apply to the Victorian DNSPs in the 2011–15 regulatory control period. The adjustments to the building blocks are as set out in table 15.12. Below is an illustration of the manner in which the AER has calculated these building blocks:

1. The DNSPs' reliability performance for 2010 ($ACT_{2010}^{r,n}$) is estimated, because the actual performance will not be known until part way through 2011. DNSPs have provided their best estimates of actual performance in 2010.
2. S"t is calculated for t = 2011 using actual performance ($ACT_{2008}^{r,n}$ and $ACT_{2009}^{r,n}$) in accordance with section 2.3.9(ii) of the 2006 EDPR volume 2. S"t is calculated for t = 2012 using actual performance ($ACT_{2009}^{r,n}$ and $ACT_{2010}^{r,n}$) in accordance with section 2.3.9(ii) of the 2006 EDPR volume 2.
3. S"t is calculated for t = 2013 in accordance with section 2.3.9(ii) of 2006 EDPR volume 2, using $ACT_{2010}^{r,n}$ and an assumed level of performance ($ACT_{2011}^{r,n}$) set equal to the average performance, as measured by the S factor scheme, over the period 2005–10.
4. S"t is calculated for the years t = 2014 to t = 2018 in accordance with section 2.3.9(ii) of 2006 EDPR volume 2 and by setting $ACT_{t-3}^{r,n}$ equal to $ACT_{t-2}^{r,n}$ at the average performance, as measured by the S factor scheme, over the period 2005–10. This results in S"t being equal to 0 from 2014 onwards.
5. Prior to t = 2012, $S_{bank,t}$ and $S_{bank,t-1}$ are applied in the manner the AER was advised by the DNSPs. For t = 2013, $S_{bank,t}$ is set at 0—as DNSPs are not permitted to bank deemed performance in 2011. From t = 2014 onwards both $S_{bank,t}$ and $S_{bank,t-1}$ are set at 0.
6. The WACC to apply in the banking calculation is the 2006–10 EDPR pretax $WACC_D$, as applied in section 2.3.9(ii) of the 2006 EDPR.
7. S't for t = 2010 to t = 2019 are calculated in accordance with section 2.3.9(ii) of 2006 EDPR volume 2, The AER notes that, as performance is assumed to remain constant from 2011 onwards, this results in S't becoming 0 from 2014 onwards and S't-6 becoming 0 from 2019 onwards.
8. St is calculated for 2011–18 in accordance with the ESCV S factor scheme. The AER notes that St becomes zero from 2019 onwards and at this time the effects of the ESCV S factor scheme have been fully accounted for.

[145] As such $ACT_{t-3}^{r,n}$ is equal to the average of 2005–10 performance for t = 2014 onwards and this results in S"t being equal to 0 from 2014 onwards.

9. The St for each year, from 2011–18, is applied to forecast revenues. For the years 2011–15, the forecast revenue is the approved 2010 tariff prices multiplied by the forecast sales quantities for the relevant year. The forecast sales quantities are those approved by the AER in the PTRM. For the years 2016–18, forecast revenues are to be held constant at 2015 levels.
10. The S factor is applied to the forecast revenues for 2011–20. For 2011–15, the differences between the estimates of tariff revenues, excluding and including the S factor, are applied as a building block.
11. For the years 2016–18 the differences between the estimates of tariff revenues, excluding and including the S factor, are converted to 2015 values in net present value (NPV) terms and applied to the building blocks in 2015. The WACC applied to this NPV calculation is the 2011–15 EDPR WACC.

Table 15.12 AER conclusion on the building blocks resulting from the ESCV S factor true-up ($ million, 2010)

	2011	2012	2013	2014	2015
CitiPower	– 2.19	– 4.50	– 3.33	– 0.33	– 3.54
Powercor	– 5.95	– 20.94	– 5.22	– 0.31	0.82
JEN	5.46	0.92	– 0.20	– 0.19	– 9.75
SP AusNet	40.22	20.21	– 7.04	– 1.59	– 78.87
United Energy	– 4.80	– 4.80	– 6.21	– 6.15	– 10.83

15.6.7 Final adjustment for 2010 actual performance

15.6.7.1 AER draft decision

In the draft decision the AER noted that in order to accurately close out the ESCV S factor scheme, actual performance for 2010 is required. This information will only be available in the first quarter of 2011, after the publication of the AER's final determination.

The value for closing out the ESCV S factor scheme, calculated in accordance with the methodology set out in section 15.6.6.5, uses an estimate of the 2010 performance. This estimate impacts on the both the payout for 2010 and the estimate of ongoing performance used to close out the scheme. A final adjustment will be required to accurately reflect the actual 2010 performance of the DNSPs.

The AER noted that this reconciliation was not included in the form of control as set out in the Framework and approach paper. The AER did not consider a pass through appropriate. Further, given the constraints in the NER on amending the form of control from that specified in the Framework and approach paper, the AER also considered that the addition of a parameter in the price control formula is not appropriate.[146]

The AER considered that the final reconciliation of actual 2010 performance under the ESCV S factor scheme will be addressed in the 2016–20 distribution determination.

15.6.7.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor did not accept the AER's decision not to incorporate the S factor true up into the WAPC formula in the draft decision and to instead leave it to the 2016–20 distribution determination. CitiPower and Powercor submitted that the AER should include a new term in each of the WAPC formula and the side constraint formula to address the S factor true up. CitiPower and Powercor stated that:

> in the South Australian and the Queensland Final Determinations, the AER took the view that, while the form of control mechanism (e.g. from a WAPC to a revenue cap) must be as set out in the relevant Framework and Approach Paper, the WAPC and side constraint formulae could be amended to include an additional term (and the AER did, in fact, add new terms to the WAPC formula in those Final Determinations even though no such terms were included in the WAPC formula in the relevant Framework and Approach Paper); and
>
> perhaps more significantly, in the South Australian and Queensland Final Determinations, the AER established a mechanism for the calculation of transmission related payments to be passed through by ETSA and the Queensland DNSPs pursuant to their pricing proposals, referred to as the 'TuOS unders and overs account'. While clause 6.18.7 of the Rules only contemplates the pass through of TuOS charges via a DNSP's pricing proposal, the AER nonetheless explicitly provided for the pass through by ETSA and the Queensland DNSPs of certain of the Transmission-related Costs presently in issue, namely avoided TuOS payments and inter-DNSP payments, in the AER's 'TuOS unders and overs account'.[147]

Powercor contended that:

> If clause 6.12.3(c) does not permit the AER to amend the price control formula from that set out in the Framework and Approach Paper, then each of these decisions by the AER and the South Australian Final Determination were made in breach of the Rules.
>
> Powercor Australia considers that clause 6.12.3(c) does not prevent the AER from adding a new term to the WAPC formula, and that the AER's interpretation of clause 6.12.3(c) as set out in the South Australian Draft Determination is correct.[148]

JEN also did not accept the AER's draft decision and stated that:

> The AER’s proposal for a true-up adjustment to the 2016-2020 building block revenue requirement at the 2015 price review does not adequately address JEN’s concerns regarding fair and accurate true-up for the transition

[146] AER, *Draft decision*, 2010, p. 682.
[147] CitiPower, *Revised regulatory proposal*, p. 20; Powercor, *Revised regulatory proposal,* p. 20.
[148] Powercor, *Revised regulatory proposal,* p.64.

> to the AER's proposed STPIS scheme. JEN is concerned that the AER cannot bind itself or any future regulator to give effect to statements of intent at the next price review. These concerns are warranted given the AER's rejection of JEN's proposal to recover the financing costs on capex overspends as foreshadowed by the ESCV.
>
> Further, JEN notes that one of the reasons the AER states for rejecting JEN's S factor true-up proposal is that the Rules constrain the AER to follow its WAPC formula in its F&A paper. JEN notes that this reasoning is at odds with its introduction of an entirely new 'pass through' pricing parameter into this WAPC formula.[149]

15.6.7.3 Submissions

The AER did not receive any submissions on this matter.

15.6.7.4 Issues and AER considerations

The AER considers that clause 6.12.3(c) of the NER generally constrains the AER from altering the WAPC formula as set out in the Framework and approach paper. It notes that under certain circumstances, it may have to depart from this position in order to achieve a suitable outcome and to meet the NEO. For example, in this Victorian final decision, the AER has included a ± pass through term in the WAPC formula. In this particular case, the AER considers that implementing a pass through mechanism was contemplated at the time of the Framework and approach paper and that it was an omission that this term was not included in the WAPC formula in the Framework and approach paper. Further, the AER considers that not including the pass through term in the WAPC formula would render the regulatory framework unworkable. The AER considers that without specifically including a pass through term in the WAPC formula, it would not be possible to provide DNSPs with any pass throughs that are required—that is, there is no alternative mechanism to achieve the necessary outcome.

The Framework and approach paper specifically stated that 'the benefits and penalties accrued in the current regulatory control period under the ESCV scheme will not be incorporated in the price cap formula [WAPC]. Rather, financial carryover amounts from the current regulatory control period will be included as a building block element in the calculation of allowed revenue for the next regulatory control period.'[150] The AER considers that this statement is binding on the AER. Furthermore, the AER considers that there are alternative methodologies available to achieve the required outcome. Specifically, the AER intends to account for the differences between forecast and actual 2010 performance as part of the next Victorian distribution determination covering the period 2016–20. As such, the AER considers that the regulatory framework continues to function without the inclusion of the S factor term in the WAPC formula.

The AER considers that it is generally bound by the WAPC formula as set out in the Framework and approach paper. In relation to adding an S factor true up term to the WAPC, the AER specifically stated in the Framework and approach paper that it would not adopt this approach. Further, there are appropriate alternatives available to

149 JEN, *Revised regulatory proposal*, p. 23.
150 AER, *Framework and approach*, May 2009, p. 94.

the AER to implement this true up. As such, the AER does not consider it appropriate to amend the WAPC formula in these circumstances.

The AER notes JEN's concern that the AER cannot bind itself, or a future regulator, to a statement of intent at the next price review. As this final true up process is clearly identified in this final decision, the AER expects that this decision will be part of the basis for the 2016–20 regulatory control period, similar to the AER's process in recognising the construction of the existing ESCV S factor scheme.

15.6.7.5 AER conclusion

The AER has concluded that, as it is generally constrained from altering the WAPC—as set out in the Framework and approach paper—the financial benefits and penalties accrued in the 2006–10 regulatory period under the ESCV S factor scheme will be included as a building block element in the calculation of allowed revenue for the 2011–15 regulatory control period.

The final reconciliation of actual 2010 performance under the ESCV S factor scheme, will be addressed in the 2016–20 distribution determination.

15.6.8 Interactions between the ESCV S factor scheme and the STPIS

In section 15.6.6.5 the AER concluded that the best manner in which to close out the ESCV S factor scheme is to use the method proposed in the draft decision, modified to use the 2005–10 average performance, as an estimate of the ongoing performance from 2011.

Several stakeholders' submissions requested the AER to consider the interaction between the ESCV S factor scheme and the STPIS and to ensure that Victorian DNSPs did not receive a windfall gain or loss from transitioning to the STPIS. The AER has considered these transitional issues and concludes that the methodology adopted in section 15.6.6.5 appropriately deals with all issues raised.

15.6.8.1 Revised regulatory proposals and submissions

United Energy stated that:

> It is also noted that the AER's close out mechanism has the effect of continuing the operation of the ESCV's scheme to 2016, even though a new service incentive scheme, the STPIS, is to be introduced at the commencement of the forthcoming regulatory period. An appropriate close out arrangement would prevent the ESCV's scheme from continuing into the forthcoming regulatory period. The operation of two schemes in parallel is also inconsistent with [the original objectives of the scheme].[151]

The Minister submitted that, in moving from the ESCV S factor scheme to the AER's STPIS, the specific circumstances of the Victorian DNSPs have not been taken into account. In the 2006–10 regulatory period, reliability improvements are funded through the ESCV S factor scheme rather than through the expenditure building blocks. The Minister stated that, as a result, customers have been paying for reliability improvements and that the improvements have not effectively been factored into setting the 2011–15 targets, which will result in windfall gains or losses. In addition,

[151] United Energy, *Revised regulatory proposal*, p. 219.

the Minister stated that the windfall gains or losses will be magnified by an increase in the value of customer reliability which provides a perverse incentive for deteriorations in performance during the latter stages of the 2006–10 regulatory period. The Minister submitted that the AER must carefully consider this transitional issue to minimise potential windfall gains or losses and perverse incentives.

15.6.8.2 Issues and AER considerations

Windfall gains and losses

The Victorian DNSPs have presented examples of the manner in which the two schemes can be best aligned to eliminate any windfall gain or loss. However, no example has accounted for the fact that the incentive rates and exclusion criteria differ between the two schemes. As such, the AER does not consider that any DNSP has presented a method of closing out the ESCV S factor scheme which entirely eliminates the possibility of a windfall gain, or loss.

The AER considers that the methodology proposed by CitiPower and Powercor, as modified by the AER and adopted in this final decision, appropriately minimises the probability of a windfall gain, or loss. This is because the AER's methodology closely replicates the payouts that would have occurred under the ESCV S factor scheme.

To the degree that future performance differs from the estimate of ongoing performance used to close out the ESCV S factor scheme, there may be some further gain, or loss, to DNSPs. The AER has used the best estimate of ongoing performance available in order to minimise this possibility. Additionally, to the degree that the exclusion criteria and incentive rates differ between the two schemes, there may be some further gain, or loss, to a DNSP. However, this is an unavoidable impact of transitioning between the two schemes. The AER does not consider that any of the methodologies presented eliminates the possibility of a windfall gain or loss from closing out the ESCV S factor scheme and commencing the AER's STPIS. As such, the AER considers it is important to close out the ESCV S factor scheme in the manner that most closely replicates the intended application of the scheme.

Aligning target between the schemes

The Minister illustrated the potential for windfall gains, or losses, to arise due a mismatch between the end point of the ESCV S factor scheme and the targets under the STPIS. The AER considers that its methodology best addresses concerns regarding the transition between the two schemes. The AER considers that, in closing out the ESCV S factor scheme, it has ensured that both DNSPs and consumers have been fairly compensated for the reliability improvements (or deteriorations) that they have received. This is because the methodology chosen to close out the ESCV S factor scheme best replicates the intended outcomes of the ESCV S factor scheme. Further, by incorporating an estimate of underlying performance into its methodology and basing this estimate on the 2005–10 average performance under the ESCVS factor scheme, the AER has largely aligned the end point of the ESCV S factor scheme with the start of the STPIS—hence, minimising the potential for windfall gains or losses. The AER considers that this approach addresses the Ministers concerns.

The performance targets for the STPIS are consistent with the capex and opex allowances for the 2011–15 regulatory control period approved in sections 8.7.4 and

7.1.1. These capex and opex allowances provide for maintaining reliability levels over the 2011–15 regulatory control period. Using the AER's close out method, the AER considers that any service improvements from the 2006–10 regulatory period, will be appropriately rewarded, or penalised, under the ESCV S factor scheme. Any improvements resulting from the ESCV S factor scheme are reflected in the targets which will be applied in the 2011–15 regulatory control period. Further, any service improvements in the 2011–15 regulatory control period will be rewarded, or penalised, under the STPIS.

The Minister also expressed concerns that the AER’s methodology in its draft decision results in a perverse incentive for deteriorating performance in the final years of the ESCV S factor scheme as the incentive rate is lower than the STPIS. A DNSP would incur a smaller penalty for degraded performance in 2009 or 2010, than it would receive as a benefit for a corresponding improvement in 2011 onwards. The AER considers this issue has been minimised by the methodology the AER has now adopted. In addition, the Electricity Distribution Code (EDC) requires that DNSPs must use best endeavours to develop and implement good asset management policy, and to maintain and operate its distribution system to minimise the risks associated with the failure or reduced performance.[152] If a DNSP acts in a manner inconsistent with the EDC, the AER will take enforcement action.

Two incentive schemes operating concurrently

United Energy contended that the AER’s methodology in effect results in two incentive schemes operating at the same time. United Energy stated:

> It is also noted that the AER’s close out mechanism has the effect of continuing the operation of the ESCV’s scheme to 2016, even though a new service incentive scheme, the STPIS, is to be introduced at the commencement of the forthcoming regulatory period. The operation of two schemes in parallel is also inconsistent with [the original objectives of the scheme].[153]

The AER's close out of the ESCV S factor scheme will impose revenue increments, or decrements, in the 2011–15 regulatory control period. These adjustments are based upon an assumption regarding the level of ongoing performance. However, this performance assumption is based on historical data from the 2006–10 regulatory period, and is held constant (which has the effect of closing out the ESCV S factor scheme). Further, the calculated increments or decrements are not influenced in any manner by a DNSP's performance in the 2011–15 regulatory control period. For clarity, 2010 performance and previous years is rewarded or penalised under the ESCV S factor scheme and 2011 performance onwards is rewarded or penalised under the STPIS. The overlap in the timing of the revenue increments, or decrements, is simply due to the different payout profiles of the two schemes. As such, no Victorian DNSP will be subjected to incentives under both schemes simultaneously as the two schemes do not operate in parallel as suggested by United Energy.

15.6.8.3 AER conclusion

In section 15.6.6.5 the AER set out its methodology to close out the ESCV S factor scheme. The AER has also investigated the interactions between this methodology

[152] Clause 3.1 of the EDC.
[153] United Energy, *Revised regulatory proposal*, p. 46.

and the operation of the STPIS. The AER has concluded that the methodology chosen to close out the ESCV S factor scheme minimises the possibility of a windfall gain or loss to the Victorian DNSPs due to the transition between the two schemes.

15.6.9 Calculation of incentive rates

This section sets out the calculation and assumptions underlying the incentive rates for the SAIDI, SAIFI, MAIFI and customer service parameters for the 2011–15 regulatory control period.

15.6.9.1 AER draft decision

The AER considered it appropriate to apply the incentive rate calculation as set out in appendix B of the STPIS. The AER requested that the Victorian DNSPs resubmit an estimate of their forecast average annual energy consumption, as both this and the Victorian DNSPs' annual smoothed revenue requirement are inputs into the calculation of the incentive rates. The AER stated that it will update the incentive rates for any relevant changes between the AER's draft and final decisions.[154]

15.6.9.2 Victorian DNSP revised regulatory proposals

United Energy submitted that:

> The AER has applied the method of calculating incentive rates which is set out in sections 3.2.2 and 5.3.2 of the STPIS. UED accepts the overall approach to the calculation of incentive rates, but has doubts about the validity of the underlying data which has been used by the AER.
>
> UED notes that the AER has not explained the source of much of the component data which has been employed in the evaluation. In particular, the AER has not documented:
>
> - The source of the average annual energy consumption data, measured in megawatt hours (MWh), and shown separately for urban feeders and for short-rural feeders.
> - The forecast inflation rate for calendar year 2010 which has been used to escalate the Value of Customer Reliability (VCR).
>
> UED notes that the VCR published by CRA International in August 2008 was $47.85/kWh in current prices. Clause 3.2.2(b) of the amended STPIS document states that the VCR will be adjusted for CPI from the September quarter 2008 to the start of the relevant regulatory control period. In a September 2009 explanatory statement outlining proposed amendments to the STPIS, the AER also stated that the CPI used to escalate the VCR to the start of the regulatory control period would be the CPI used to roll forward a distributor’s asset base in the roll forward model. However, in the Draft Decision for Victoria, it is unclear whether the AER has applied consistent inflation rates.[155]

15.6.9.3 Issues and AER considerations

The explanatory statement of the STPIS stated that the CPI used to escalate the VCR to the start of the 2011–15 regulatory control period would be the CPI used to roll

[154] AER, *Draft decision*, 2010, p. 645.
[155] United Energy, *Revised regulatory proposal*, p. 290.

forward a DNSP's asset base in the roll forward model.[156] However, in its draft decision the AER used forecast inflation rates from the Reserve Bank of Australia in its calculation of CPI. The AER has now applied a lagged CPI calculation to adjust the VCR to real 2010 dollars in a manner consistent with the roll forward model as stated in the STPIS explanatory statement.

The calculation of the incentive rates uses forecasts of annual energy consumption consistent with the total energy consumption forecasts approved by the AER in chapter 5 of this final decision. The calculation of the incentive rates also uses smoothed revenue consistent with the revenue calculated in the Post Tax Revenue Model and approved in this final decision.

Finally, the SAIDI and SAIFI targets, used to calculate the incentive rates, are consistent with the targets approved in this final decision.

15.6.9.4 AER conclusion

The AER has calculated and will apply the incentive rates set out in table 15.13.

[156] AER, *Explanatory statement, Proposed amendment Service target performance incentive Scheme Electricity distribution network service providers February 2009*. p 16.

Table 15.13 AER conclusion—Incentive rates (per cent per unit)

	CitiPower	JEN	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI	0.1259	–	–	–	–
SAIFI	6.7499	–	–	–	–
MAIFI	0.5400	–	–	–	–
Urban	–	–	–	–	–
SAIDI	0.0733	0.1054	0.0474	0.0334	0.1088
SAIFI	3.7572	6.6017	3.1881	2.4242	6.8707
MAIFI	0.3006	0.5281	0.2550	0.1939	0.5497
Rural short	–	–	–	–	–
SAIDI	–	0.0046	0.0274	0.0287	0.0122
SAIFI	–	0.2949	2.1849	2.4696	0.7572
MAIFI	–	0.0236	0.1748	0.1976	0.0606
Rural long	–	–	–	–	–
SAIDI	–	–	0.0238	0.0139	–
SAIFI	–	–	2.3799	1.1687	–
MAIFI	–	–	0.1904	0.0935	–

Source: AER analysis.

15.6.10 Proposed bushfire related exclusion criteria

In July 2010 the Victorian Bushfires Royal Commission (VBRC) released its final report, which included a recommendation for:

> The State (through Energy Safe Victoria) require distribution businesses to do the following:
>
> - disable the reclose function on the automatic circuit reclosers on all SWER lines for the six weeks of greatest risk in every fire season
> - adjust the reclose function on the automatic circuit reclosers on all 22-kilovolt feeders on all total fire ban days to permit only one reclose attempt before lockout.[157]

SP AusNet proposed to change its safety management scheme because of these recommendations.

[157] 2009 Bushfires Royal Commission, *Final Report Summary, July 2010*, section 2, p. 30.

15.6.10.1 AER draft decision

SP AusNet did not propose bushfire related exemptions in its initial regulatory proposal. Therefore the issue was not considered by the AER in its draft decision.

15.6.10.2 Victorian DNSP revised regulatory proposals

In its revised proposal, SP AusNet proposed a variation to clause 3.3 of the STPIS to include an additional exclusion to deal with the effects of its bushfire risk mitigation initiative. SP AusNet submitted that the variation to clause 3.3 was needed because the impact on supply reliability is a non-cost event, which cannot be dealt with by a pass through.[158]

The VBRC's final report had not been released at the time SP AusNet was required to lodge its revised regulatory proposal. SP AusNet advised that the revised regulatory proposal was instead based on the recommendations made by the Counsel Assisting to the VBRC—that the auto reclose function on lines be suppressed, or the number of auto recloses reduced, in high bushfire risk areas for the entire fire season.[159] SP AusNet proposed:

> …an alternative option to automate circuit reclosers in high bushfire risk areas to allow protection and reclose settings to be remotely adjustable in accordance with the forecast Fire Danger Index. That means total fire ban days can be targeted rather then the entire fire season, dramatically reducing the value of unserved energy resulting from such a policy.
>
> Regardless of the approach eventually recommended, there will be a measurable decrease in the reliability of supply in these areas of SP AusNet's network as transient faults will not be cleared (turning MAIFI events into SAIFI and SAIDI events)…[160]

Subsequent to the release of the VBRC's final report, SP AusNet provided additional information to the AER regarding the estimated changes in network reliability impact due to the different auto-recloser scheme—that SWER auto-reclosers be turned to 'no reclose' for the duration of the fire season and 3 phase auto-reclosers be turned to two recloses rather than four on total fire ban days.[161]

SP AusNet proposed an approach to assess the impact of the recommendations using a post event analysis. After a fault occurs on the relevant lines, SP AusNet will inspect the lines for the cause of the fault.[162] If no cause is found, then it intends to exclude the event as it would have been avoided by the use of auto reclosers, had the function not been suppressed.[163]

SP AusNet also noted that:

158 SP AusNet, *Revised regulatory proposal*, p. 49.
159 ibid., p. 49.
160 Ibid., p. 49.
161 SP AusNet, *email*, 6 August 2010.
162 ibid.
163 ibid.

> …SP AusNet believes it would be prudent to allow the DNSP's the opportunity to propose a bushfire risks mitigation method without the need for a change in the jurisdictional electricity legislation.[164]

15.6.10.3 Submissions

The Consumer Action Law Centre submitted that the AER should not approve SP AusNet’s proposal to turn off auto reclose devices during the fire season in high risk areas as recommended by the VBRC until a decision by the Victorian Government is made.[165]

15.6.10.4 AER issues and considerations

The bushfire mitigation scheme was not mentioned by SP AusNet in its initial regulatory proposal because at that time, the VBRC and the Counsel Assisting the VBRC had not made any recommendations. As the details of this matter were not available at the time of SP AusNet's initial regulatory proposal, the AER is willing to consider the matter in this final decision.

SP AusNet has informed the AER that its Electricity Safety Management Scheme (ESMS) for bushfire mitigation is being assessed by Energy Safe Victoria (ESV). If the ESMS is approved under the *Electrical Safety Act 1998*, SP AusNet must comply with the ESMS under section 106 of the *Electrical Safety Act.*

The STPIS is not currently under review and so no new exclusions can be added to it at this time. However, under clause 3.3 of the STPIS, the AER may exclude load interruptions caused by the exercise of any obligation under jurisdictional electricity legislation or national electricity legislation. If SP AusNet's ESMS is approved by ESV, in this instance the AER acknowledges that avoidable supply interruptions due to the suppression of auto-reclose schemes will meet this exclusion criterion. This approach is consistent with the approach taken by the AER with respect to Victorian DNSPs' ESMS when assessing the opex step changes. The AER will asses on a case by case basis whether to allow exclusions in relation to obligations contained in the Victorian DNSPs' ESMSs, having regard to the objectives of the STPIS.

Adjustment of performance targets

The AER has assessed proposed operation of SP AusNet's bushfire mitigation ESMS plan regarding the impact on its supply reliability performance. The AER does not consider that the mitigation plan will change the performance indicators of SAIDI or SAIFI performance. SP AusNet proposed to have a post exclusion of all SAIDI events, which will occur during the period when the auto reclose devices are suppressed.[166] SP AusNet intends to exclude those events which would have been avoided by use of the auto reclosers but not those events where a fault is found that would not have been avoided by auto reclosers.[167] SP AusNet notes:

> There is a risk with this approach that faults that the Auto-Recloser would not have cleared that in the past would have been identified as No Cause Found would be excluded. Currently 2.5% of faults seen by Auto-Recloser’s are of this nature and therefore, the number that would be normally expected

[164] ibid.
[165] CALC, *Submission*, appendix p. 5, 6.
[166] SP AusNet, *email*, 6 August 2010.
[167] ibid.

> to occur during the 6 week period would be 1 compared to 180 under the exclusion criteria. Therefore, the risk that a large event is unnecessarily excluded is minimal.[168]

The AER is satisfied that the sustained outages to be excluded because of this aspect of the ESMS would have been avoided if the auto reclose devices were not suppressed. In other words, such outages would not have occurred without the implementation of the scheme. The AER, however, considers that the mitigation plan will reduce SP AusNet's MAIFI because the auto recloses will be suppressed on certain days. Consequently, the AER requested that SP AusNet provide information on the impact of the scheme on MAIFI so as to adjust the MAIFI target downwards.[169] SP AusNet submitted that:

> In the situation an auto-recloser is unable to operate as designed (reclose), momentary interruptions may become sustained interruptions. The exclusion criteria would exclude the sustained interruption from the calculation of performance targets however the momentary interruption would also no longer occur. This would result in a reduction in momentary interruptions and would require an adjustment to targets. However, the most appropriate method would to be convert any outage that was excluded into a MAIFI of the same magnitude as the USAIFI excluded. This removes the necessity to have adjustments to targets.[170]

The AER did not consider that SP AusNet's proposal was appropriate given the design of the STPIS. This is because the AER does not consider that the STPIS allows for the AER to exclude an event under clause 3.3 and to then replace the excluded event (SAIDI in this case) with a deemed outage event of another type (MAIFI).

By implementing the ESMS, SP AusNet's operating environment is in effect changing. Hence, its historical performance would not accurately reflect this operational change. Therefore, the AER considers that an adjustment to the target is necessary. The AER requested SP AusNet to provide a revised MAIFI target together with an explanation of the methodology used to calculate the new target, to account for the reduction in MAIFI due to the suppression of auto reclosers.[171] SP AusNet provided the required information and the AER assessed the methodology and assumption used in SP AusNet's calculation.[172] The AER considers that the methodology and assumptions used are reasonable. SP AusNet's calculated impact of the proposed scheme on the MAIFI target is shown in table 15.14.

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168 ibid.
169 AER, *email*, 25 August 2010.
170 SP AusNet, *email*, 3 September 2010.
171 AER, *email*, 25 August 2010; AER, *email*, 7 September 2010.
172 SP AusNet, *SPA - Calculation of Performance Targets 2011 - 2015 (Revised - 13-09-10 - ACR)*, received 16 September 2010.

Table 15.14 SP AusNet's calculated MAIFI adjustment

	Total fire ban days MAIFI reduction	SWER auto reclose suppression MAIFI reduction
Urban	0.002	–
Rural short	0.029	0.01
Rural long	0.096	0.05
Total	**0.033**	**0.014**

Source: SP AusNet, SPA - Calculation of Performance Targets 2011 - 2015 (Revised - 13-09-10 - ACR), received 16 September 2010. Calculated on 2.8 beta from the mean MED threshold.

15.6.10.5 AER conclusion

The AER considers that avoidable supply interruptions due to the suppression of the auto-recloser system under an approved ESMS would meet the exclusion criteria under clause 3.3(a)(7) of the STPIS. In this regard, the AER has taken into account the regulatory obligations and requirements that SP AusNet is required to meet.

In order to ensure that there is no windfall gain, the AER will adjust SP AusNet's MAIFI target down by the amounts outlined in table 15.14 for the 2011–15 regulatory control period. In making this MAIFI adjustment, the AER has had regard to the past performance of SP AusNet's network. This adjustment is reflected in the targets set out in table 15.11

15.6.11 Interaction between the cap on revenue at risk and the s-bank

In accordance with section 2.5 of the STPIS, a DNSP's revenue at risk for supply reliability performance is capped. The revenue cap is applied before a DNSP can bank its performance revenue.

15.6.11.1 Victorian DNSP revised regulatory proposals

SP AusNet submitted that the current banking formula can lead to a perverse outcome, whereby the banking mechanism increases rather than decreases the volatility of the STPIS. SP AusNet proposed to allow the voluntary banking mechanism to apply before enacting the cap on revenue at risk at clause 2.5(a) of the STPIS. It contended that this would be in the best interest of DNSPs and consumers. SP AusNet submitted that:

> The better option would be to cap S’t which takes into account banking before assessing whether the cap has been breached.[173]

15.6.11.2 AER issues and considerations

The STPIS, clause 2.5(a) states that:

> Subject to clause 2.5(b), and excluding the GSL component described in clauses 6.1–6.4, the maximum revenue increment or decrement (the revenue at risk) for the scheme components in aggregate for each regulatory year

[173] SP AusNet, *Revised regulatory proposal*, p. 34.

> within the regulatory control period shall be 5%, that is, the sum of the s-factors associated with all parameters must lie between +5% (the upper limit) and –5% (the lower limit).

The AER considers that SP AusNet's proposal relates to the design of the STPIS, which is not currently under review. In addition, the proposal is inconsistent with the scheme's intent, as it may artificially increase the amount of revenue at risk beyond the willingness of an end user to pay for improved performance.

Further, the AER's analysis indicates that SP AusNet's proposed approach may introduce asymmetry in the amount of rewards and penalties for reliability performance. Under SP AusNet's proposed approach a DNSP may cap the downside risk of a reduction in revenue at the capped amount, by not banking a reduction in revenue beyond the capped amount. However, a DNSP may increase the upside cap for any year's performance by banking revenue in a year where positive revenue—beyond the cap—is achieved. The AER does not consider this to be a desirable outcome.

SP AusNet submitted that the current banking formula can have a perverse outcome, where the banking mechanism increases rather than decreases the volatility of the STPIS. The AER considers that, depending on a DNSP's banking strategy, there is the possibility for consumers and DNSPs to experience increased revenue volatility due to the operation of the s-bank. However, as noted in section 15.7.3 of the draft decision, this volatility can be reduced by applying a consistent banking approach and can be significantly reduced by applying some discretion to the banking aimed at reducing the volatility.[174]

15.6.11.3 AER conclusion

The AER concludes that SP AusNet's submission is inconsistent with the design of the scheme. In addition, the AER's analysis indicates this proposal may have an undesirable outcome. The AER will apply the revenue at risk cap before the banking mechanism in the 2011–15 regulatory control period as specified in the STPIS.

15.6.12 Five minute MAIFI proposal

JEN proposed that the AER modify the definition of MAIFI from a one minute period to a five minute period in its initial regulatory proposal. JEN believed that its proposal would:

- better support developments in future self-healing networks so that remote re-configuration of the network can be further encouraged given the relaxation in time duration
- align the event with the IEEE standard

[174] AER, *Draft decision*, 2010, pp. 641–642.

- allow current MAIFI performance data to form the basis of the targets by ensuring future performance is measured on a comparable basis.[175]

15.6.12.1 AER draft decision

The AER retained the ESCV's definition of MAIFI for transitional reasons.[176] This MAIFI definition measures momentary interruptions for outages less than, or equal to, one minute.[177] The AER did not explicitly outline its reasons for not allowing JEN's proposed change to the definition of MAIFI. The AER's reasons for not allowing the definition change are outlined below.

15.6.12.2 Victorian DNSP revised regulatory proposals

SP AusNet accepted the AER's draft decision to apply the ESCV's MAIFI definition during the 2011–15 regulatory control period.[178] CitiPower and Powercor accepted the position set out in the draft decision.[179] United Energy accepted the AER's MAIFI target which was calculated under the ESCV's MAIFI definition.[180]

JEN stated that:

> Whilst JEN appreciates the need to maintain consistency (which is understood to be a factor in the AER deciding to retain the ESCV's MAIFI definition), JEN is none-the-less disappointed that its reasoning for a 5 minute period has been ignored and, by implication, rejected.[181]

15.6.12.3 AER issues and considerations

In its draft decision, the AER considered it appropriate to apply the ESCV definition of MAIFI that had applied during the 2006–10 regulatory period. Regardless of this conclusion, the AER does not consider that adjusting MAIFI to a five minute definition would be consistent with the objectives of the scheme. This is because JEN's proposal would see a reallocation of outage events between the MAIFI parameter and both the SAIFI and SAIDI parameters.

Under the STPIS, there is a significantly lower incentive rate applicable to MAIFI than either SAIFI, or SAIDI, and the AER does not consider it appropriate to have outages of up to five minutes in duration subject to this lower incentive rate.[182]

Further, the AER notes that CitiPower, Powercor and United Energy proposed a change to the definition of MAIFI from one minute to three minutes during the ESCV's 2006–10 EDPR process.[183] At that time, it was noted that willingness to pay information regarding MAIFI is based on a one minute definition.[184] The MAIFI value of customer reliability applied in the STPIS is also based on the value adopted

175 JEN, *Regulatory proposal 2011–2015*, 30 November 2009, p. 197.
176 AER, *Draft decision*, 2010, pp. 670–676.
177 ESCV, *Information Specification (Service Performance) for Victorian Electricity Distributors*, 1 January 2009, p. 30, 31.
178 SP AusNet, *Revised regulatory proposal*, p. 44.
179 CitiPower, *Revised regulatory proposal*, p. 397; Powercor, *Revised regulatory proposal*, p. 396.
180 United Energy, *Revised regulatory proposal*, p. 289.
181 JEN, *Revised regulatory proposal*, p. 283.
182 Pursuant to clause 3.2.2(j)(1) the default MAIFI incentive rate is 8 per cent of the SAIFI incentive rate.
183 ESCV, *2006–10 EDPR Final Decision Vol 1*, p. 44.
184 ibid, pp. 44–86.

by the ESCV.[185] Neither JEN's initial or revised regulatory proposal commented on whether it considered its proposal would have any impact on customers' willingness to pay.

15.6.12.4 AER conclusion

Consistent with its draft decision, the AER will apply the ESCV's MAIFI definition for the 2011–15 regulatory control period for all Victorian DNSPs for the purpose of setting performance targets and measuring performance under the STPIS.

15.6.13 Performance calculation when cap on revenue is exceeded

15.6.13.1 Victorian DNSP revised regulatory proposals

SP AusNet submitted that:

> The current STPIS Guidelines does not address the issue of how to calculate targets for the subsequent regulatory control period in the event of the revenue cap binding in the preceding regulatory control period.
>
> SP AusNet considers the guidelines should formally state the targets for the next period would be set based on the capped performance rather than actual performance and should outline the process for how this will occur.
>
> This ensures that the benefits or penalties from performance outside the cap are eventually paid out to the DNSP or end users. This mechanism would provide the correct incentives for a DNSP to continuously improve its delivery of efficient network services.[186]

15.6.13.2 AER issues and considerations

SP AusNet's proposal relates to the design of the scheme, which is not currently under review. However, the AER considers that SP AusNet's concern may already be adequately dealt with by the STPIS.

The AER notes that, if a DNSP's performance is not set on the capped performance of the previous years, there may be perverse incentives placed on the DNSP. For example, if the target performance was not based on the capped performance, once the revenue cap is breached for poor performance, a DNSP would have an incentive to continue to reduce the performance of its network under the STPIS. This would increase (make easier) its target in subsequent regulatory control periods. Similarly, if the cap was breached for improving performance, a DNSP would not have a financial incentive under the STPIS to continue improving performance as it would result in a lower (more difficult) target being set in the subsequent regulatory control period. The AER considers that this issue is dealt with in section 3.2.1 of the STPIS which states:

[185] ESCV, *2006–10 EDPR Final Decision Vol 1*, p. 86; AER, *Proposed Electricity distribution network service providers service target performance incentive schem*e, Explanatory statement and Discussion paper April 2008, p. 21 22. The study asked consumers (by customer class) to place a value on a reduction in SAIFI by 1 interruption and a reduction in MAIFI by 1 interruption. The ESCV scaled the response by the number of customers in each customer class for each feeder type for the Victorian DNSPs, arriving at ratios of 8.23% to 9.13%. The average ratio indicates that consumers value a reduction in MAIFI at about 8% of the value of a reduction in SAIFI.

[186] SP AusNet, *Revised regulatory proposal*, p. 34.

> (a) The performance targets to apply during the regulatory control period must not deteriorate across regulatory years and must be based on average performance over the past five regulatory years, modified by the following:
>
> …
>
>> (1B) an adjustment to correct for the revenue at risk, that is the sum of the s-factors for all parameters, to the extent it does not lie between the upper limit and the lower limit in accordance with clause 2.5(a).

The AER will make any such adjustment having regard to the past performance of the network and any other requirements of 6.6.2(b)(3) of the NER.

15.6.13.3 AER conclusion

SP AusNet's proposal that the STPIS formally state the targets for the next period would be set based on the capped performance rather than actual performance relates to the design of the scheme which is not currently under review.

15.6.14 Proposed demand management exclusion

15.6.14.1 AER draft decision

The AER's draft decision stated:

> The AER's position is also supported in a recent report on demand side management by the Australian Energy Market Commission (AEMC).[187] In its report, the AEMC noted that the current service incentive arrangements for distribution networks do not provide a barrier to demand side participation. The AEMC stated that service incentive schemes allow DNSPs to appropriately compare levels of reliability and continuity of supply with likely penalties or benefits. The AEMC stated that demand management options:
>
>> will be considered, if they can improve reliability at relatively low cost rather than being summarily dismissed if they are considered less reliable. Rather, the possible penalty from a lower level of reliability will be considered and valued compared to the cost of the option and possible benefit. Therefore, if the cost of the DSP option is sufficiently low, and the risk of it impacting on the quality of supply can also be managed at a low cost, the network owner will prefer the DSP option.[188]
>
> The AER is not aware of any compelling evidence that would lead it to alter its position on this matter. Consistent with the STPIS, the AER will therefore not exclude non-network alternatives from data collected for the purposes of applying the STPIS.[189]

15.6.14.2 Victorian DNSP revised regulatory proposals

In its revised regulatory proposal, SP AusNet stated that it did not consider that the AER had adequate regard to clause 1.5(b)(7) of the STPIS, which states that the AER will have regard to the possible effects of the scheme on incentives for the

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187 AEMC, *Market Review of Demand Side Participation in the NEM, Stage 2 Final Report*, December 2009, p. 32.
188 Ibid., p. 32.
189 AER, *Draft decision*, 2010, p. 658.

implementation of non-network alternatives. SP AusNet also stated that the AER has not considered the early stages of development of the demand management industry.

In support of a demand management exclusion from the STPIS, Energy Response submitted that the STPIS may act as a disincentive to DNSPs' considerations of non-network demand management solutions.

15.6.14.3 AER conclusion

The AER's view on this matter has not changed from its draft decision. In reaching this conclusion the AER has had regard to the objectives of the STPIS, which are consistent with clause 6.6.2(b)(3) of the NER. Specifically, the AER has had regard to the willingness of customers to pay for improved performance in the delivery of services, and well as the need to ensure that the likely benefits are sufficient to warrant any reward or penalty under the scheme, and the possible effects on non-network alternatives. While Energy Response's comments are acknowledged, there have been no further views put forward, or information provided, which the AER considers would necessitate a change in the STPIS to exclude the DMIS.

15.6.15 Customer service parameter

The customer service parameter places incentives on DNSPs to maintain and improve their call centre fault lines performance.

15.6.15.1 AER draft decision

The STPIS definition of the telephone answering parameter differed to that applied by the ESCV, which was set out in the Information Specification for Victorian Electricity Distributors guideline and the EDPR. Under the AER's definition of the telephone answering parameter, calls to an interactive voice response (IVR) and calls abandoned within 30 seconds of being queued for response by a human operator are to be excluded from the calculation of the parameter.[190] Under the ESCV's definition, calls abandoned within 30 seconds were considered to be successfully answered calls.[191]

The Victorian DNSPs applied differing interpretations of the AER's telephone answering parameter in their initial regulatory proposals.[192] Due to the differences between the Victorian DNSPs' proposals, including the number of years of suitable data, in the draft decision the AER applied the telephone answering parameter on a DNSP specific basis.[193]

The AER calculated the telephone answering targets, in accordance with the STPIS for:

- CitiPower and SP AusNet on an average of 2005–09 telephone answering performance
- Powercor on an average of the 2006–09 telephone answering performance provided in accordance with the AER telephone answering definition

[190] AER, *STPIS*, November 2009.
[191] ESCV, *EDPR 2006–10 Vol 1*, p. 31.
[192] AER, *Victorian electricity distribution network service providers Distribution determination 2011–2015*, p. 661.
[193] AER, *Draft decision*, 2010, p. 659–668.

- United Energy, by using performance data from 2006–09
- JEN, by using performance data from 2008–09.[194]

The AER's draft customer service parameter targets are outlined in table 15.15.

Table 15.15 AER draft decision calculated customer service parameter targets for Victorian DNSPs 2011–15 (per cent)

DNSP	Target performance 2011–15 calls answered within 30 seconds
CitiPower	68.94
Powercor	62.62
JEN	57.46
SP AusNet	76.62
United Energy	58.14

Source: AER analysis

The AER also noted that, as exclusion data was not provided in a form consistent with the AER's telephone answering definition, the AER was unable to determine the exact impact of applying the exclusion criteria to its calculated telephone answering targets. Therefore, the AER required the Victorian DNSPs to provide the necessary information in order for the AER to apply the STPIS exclusion criteria to the targets in its final decision.[195] In addition, the AER did not have the actual number of calls abandoned within 30 seconds for each DNSP and so the AER required the DNSPs to provide this information for the final decision where measured.[196]

Incentive rates

The AER's draft decision was to set the incentive rate for the customer service parameter at –0.040 per cent per unit.[197]

Revenue at risk

The AER's draft decision was to set the revenue at risk for the customer service parameter at ±0.5 per cent.[198]

15.6.15.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor noted that the change in definition of this parameter means that the targets set in this decision cannot be compared to the targets set by the ESCV, or to the targets of DNSPs in other jurisdictions. In addition, CitiPower and Powercor noted that the customer service parameter previously applied by the AER in the

194 ibid, p. 667.
195 ibid, p. 666.
196 ibid, 2010, p. 666.
197 ibid, p. 666. The incentive rate is quoted as a negative number in the STPIS because, unlike for the SAIDI, SAIFI and MAIFI parameters, performance better than target performance is represented as a number greater than the target.
198 ibid., p. 667.

determinations for other jurisdictions were not consistent with the STPIS definition.[199] JEN accepted the AER's draft decision customer service target.[200] SP AusNet noted that it accepts the draft determination as calculated by the AER using previously supplied monthly data.[201]

United Energy accepted the AER's draft decision and noted that it provided the AER with the data necessary for the AER to remove the effects of excluded events from the parameter.[202] United Energy also noted that there would not have been such confusion over the calculation of the telephone answering measure if the AER had provided a formal definition in the STPIS.[203] United Energy also stated that it maintains its position that the AER should make appropriate amendments to the STPIS paper to clarify how the parameter should be calculated.[204]

15.6.15.3 AER issues and considerations

CitiPower and Powercor provided the AER with the customer service data required to calculate the target using the actual number of calls abandoned within 30 seconds and excluded events removed for the period 2007–09. The draft decision considered that CitiPower's target would be calculated from the average performance from 2005–09 and Powercor's from 2006–09, however, the AER now understands that CitiPower and Powercor were only able to measure the actual number of calls abandoned within 30 seconds for full years since 2007.[205] Therefore, the AER will use the 2007–09 average performance to set the target for CitiPower and Powercor. Powercor's target has been calculated on a 2.8 beta from the mean MED exclusion threshold as noted in section 15.4.

JEN provided the AER with daily telephone data with the actual number of calls abandoned within 30 seconds from when it began recording it partway though 2007. This enabled the AER to calculate the target performance with exclusions removed from 2008–09 actual performance as foreshadowed in the draft decision.

SP AusNet provided the AER with monthly call centre data for 2006–09 and the calculated customer service parameter target.[206] The data was provided with excluded events removed with a 2.8 beta from the mean MED exclusion threshold and included the actual number of calls abandoned within 30 seconds. The AER reviewed the information and accepts SP AusNet's calculated customer service target.

United Energy provided the AER with daily call centre data for the complete years 2006–09. The data recorded was daily data with the actual number of calls answered within 30 seconds and so could be used by the AER to calculate United Energy's performance target with exclusions removed. United Energy's target was calculated as the average of its 2006–09 performance as foreshadowed in the draft decision.

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199 CitiPower, *Revised regulatory proposal*, p. 398; Powercor, *Revised regulatory proposal*, p. 396, 397.
200 JEN, *Revised regulator proposal*, p. 287.
201 SP AusNet, *Revised regulatory proposal*, p. 44.
202 United Energy, *Revised regulatory proposal*, p. 292.
203 ibid., p. 291.
204 ibid., p. 291, 292.
205 Powercor, *email*, 9 September 2010. Powercor, *email*, 10 September 2010.
206 SP AusNet, *email*, 17 September 2010.

CitiPower and Powercor noted that there appeared to be an inconsistency between the telephone answering parameter definition applied in Victoria and that applied in other jurisdiction.[207] The AER acknowledges this inconsistency, however, it notes that both interpretations of the parameter result in substantially the same incentive, as noted in section 15.7.7 of the draft decision.

United Energy contended that there would not have been such confusion over the calculation of the telephone answering measure, if the AER had provided a formal definition in the STPIS.[208] The AER considers that the definition of the parameter contained the STPIS is clear and that the confusion appeared to result from transitional issues from the ESCV's scheme to the STPIS.

15.6.15.4 AER conclusion

The AER has calculated telephone answering targets having regard to the Victorian DNSPs' past performance of the parameter. The targets for the 2011–15 regulatory control period based on an average of actual performance in:

- 2007–09 for CitiPower and Powercor
- 2006–09 for SP AusNet and United Energy
- 2008–09 for JEN

The targets that will apply to Victorian DNSPs for the telephone answering parameter in the 2011–15 regulatory control period are outlined in table 15.16.

Table 15.16 AER final conclusion customer service parameter targets for Victorian DNSPs 2011–15 (per cent)

DNSP	Target performance 2011–15 calls answered within 30 seconds
CitiPower	71.52
Powercor	64.84
JEN	61.16
SP AusNet	82.31
United Energy	62.83

Source: AER analysis

Consistent with the STPIS, the AER will apply an incentive rate of –0.040 per cent per unit and revenue at risk of ±0.5 per cent to Victorian DNSPs for the telephone answering parameter during the 2011–15 regulatory control period.[209]

207 CitiPower, *Revised regulatory proposal*, p. 398; Powercor, *Revised regulatory proposal*, p. 396, 397.
208 United Energy, *Revised regulatory proposal*, p. 291.
209 The incentive rate is quoted as a negative number in the STPIS because, unlike for the SAIDI, SAIFI and MAIFI parameters, performance better than target performance is represented as a number greater than the target.

15.6.16 Guaranteed service levels

GSL payments currently apply under the Electricity Distribution Code (EDC) and Public Lighting Code (PLC) in Victoria. The AER's STPIS states that, where jurisdictional electricity legislation imposes an obligation on a DNSP to provide GSL payments, the AER's GSL scheme will not apply to that DNSP.

15.6.16.1 AER draft decision

The AER's preference is to apply the national GSL scheme contained in the STPIS to the Victorian DNSPs. Although the national scheme is similar to the existing Victorian scheme, the AER’s scheme has the same exclusion criteria as the STPIS S factor for supply interruption events on MED days, whereas the EDC GSL scheme applies the 2006–10 EDPR MED exclusion threshold. This may lead to potentially inconsistent incentive outcomes between the S factor and the GSL scheme.

The AER contacted the ESCV to request it to amend the EDC in order to enable the application of the national GSL scheme. Unless the existing GSL obligations are repealed, the AER must apply the Victorian GSL scheme in the 2011–15 distribution determination as required under clause 6.6.2(b)(2) of the NER, and clauses 2.1(c) and 6.1 of the STPIS.

On request from the AER, Victorian DNSPs provided their forecasts of GSL payments under the ESCV’s GSL scheme. The AER used an average of historical GSL payments as the basis for the number of forecast GSL payments in the 2011–15 regulatory control period. The AER considered it appropriate to base the forecasts upon 2005–09 data where available and appropriate, and 2006–09 data elsewhere.

The AER's draft GSL allowances to apply to the Victorian DNSPs in each year of the 2011–15 regulatory control period are outlined in table 15.17.

Table 15.17 AER draft decision on GSL payments per annum ($, nominal)

DNSP	Total payment
CitiPower	15 470
Powercor	1 176 156
JEN	18 892
SP AusNet	4 339 295
United Energy	266 810

Source: AER analysis

15.6.16.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor accepted the AER's draft decision on GSLs.[210] JEN accepted the AER’s draft decision and noted its preference for a national scheme.[211] SP AusNet

210 CitiPower, *Revised regulatory proposal*, p. 399; Powercor, *Revised regulatory proposal*, p. 397.
211 JEN, *Revised regulatory proposal*, p. 284, 289.

accepted the AER's draft GSL forecasts set out in the draft decision on the basis that the Victorian GSL scheme continues to apply.[212]

United Energy accepted the AER’s draft decision for the GSL payments other than the ‘connections not made on agreed date’ GSL.[213] United Energy stated that:

> Over the four year interval from January 2004 to September 2008, UED made GSL payments for late re-connections, as well as for delayed new connections. However, in the period since September 2008, UED has restricted the GSL payment obligation to instances of new connections which are not done within the standard connection timeframe...
>
> The AER has used the reported series for the sum of new connections and re-energisation connections from 2004 to 2008, but has then inappropriately added in the 2009 results for new connections only.[214]

United Energy submitted that the allowance using a forecast of GSL payments only incorporating new connections should be $262 072, which was less than the amount forecast by the AER of $266 810. It also noted that the forecast of the total GSL payments line item in the opex allowance need to be amended.[215]

15.6.16.3 Submissions

The Minister submitted that the AER should include a comparison of historical performance based on the existing exclusion criteria and the new exclusion criteria so it is possible to ascertain whether the interests of the worst served consumers will be compromised by reducing the number of events for which GSLs are paid.[216]

15.6.16.4 AER issues and considerations

Clarification with the Jurisdiction

In response to the AER’s request to repeal the existing Victorian GSL scheme, the ESCV advised that:

- it may be required to undertake public consultation leading to a draft and final decision, prior to codifying any amendments to the scheme in the EDC
- it wrote to the DNSPs on the implications for Victoria adopting the national GSL payment scheme at this time. In response, the DNSPs advised that they do not object to the application of the national GSL scheme, but they queried whether broader consultation has been undertaken on this matter in the current price review
- there is no certainty that the submissions to the consultation process would result in the ESCV deciding to change the current GSL payment obligations to the

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212 SP AusNet, *Revised regulatory proposal*, p. 50, 265.
213 United Energy, *Revised regulatory proposal*, p. 294.
214 ibid., p. 293.
215 ibid., p. 295.
216 The Minister for Energy and Resources, *Submission on the Victorian electricity distribution network service providers' regulatory proposals for 2009–11*, pp. 9–10.

> national GSL scheme. Therefore, there is no certainty for the DNSPs in relation to their forecast GSL obligations.[217]

In light of the above, the ESCV did not think it appropriate to amend the EDC without undertaking its normal consultation process. Further, the ESCV did not wish to pre-empt the outcome of any consultation process and was uncertain whether it would want to revoke the current obligations in favour of the national scheme.

The ESCV therefore considered that it was not in the best interests of the DNSPs and customers to undertake this consultation process at this time. Consequently, it will not commence the process to amend clause 6 of the EDC for the purposes of the 2011–15 regulatory control period.

The ESCV also advised that:

> We [ESCV] also consulted on the implications of the exclusion criteria for GSL payments being different between the current Victorian GSL scheme and the national GSL scheme. Again, the distributors would prefer consistency in this regard, but we were also advised that the different exclusion criteria for GSLs and STPIS could be retained with only minor administrative burden.[218]

As the jurisdictional GSL scheme is to continue after 2011, the AER will not apply the national GSL scheme for Victorian DNSPs for the 2011–15 regulatory control period.

Other issues and considerations

As noted, in CitiPower's and Powercor's revised proposals, they accepted the AER's draft GSL forecasts. However, they provided forecast GSL data slightly different to what the AER calculated in the draft decision.[219] The AER informed CitiPower and Powercor of this apparent inconsistency between the forecast provided in their regulatory information notices and their written proposal. The AER also informed CitiPower and Powercor that in the absence of compelling evidence to the contrary, the AER intended to apply the GSL forecasts set out in the draft decision and provided them with the opportunity to comment.[220] As no response was received, the AER will apply the GSL payment forecasts from the draft decision, as agreed by CitiPower and Powercor in their revised regulatory proposals.

United Energy's revised regulatory proposal contended that, in the draft decision, the AER inappropriately took an average of the GSL payments made from 2005–09 to forecast future GSL payment because in September 2008, United Energy discontinued making GSL payments for late re-connections.[221]

Clause 6.2 of the EDC states:

[217] ESCV, *letter*, 15 July 2010.
[218] ibid.
[219] CitiPower and Powercor, *Regulatory Information Notices*, confidential, 2010.
[220] AER, *email*, 25 August 2010.
[221] United Energy, *Revised regulatory proposal*, p. 293.

> Where a distributor does not supply electricity to a customer's supply address on the day agreed with the customer, the distributor must pay to the customer $50 for each day that it is late, up to a maximum of $250.

Under the AER's interpretation of this clause, United Energy is required to make GSL payments for late re-connections as well as late new connections. The AER is not aware of any reason why United Energy discontinued making these payments and the AER will require United Energy to make this GSL payment in accordance with the EDC during the 2011–15 regulatory control period. As part the AER's compliance role, it also intends to examine United Energy's reasons for not making these payments after September 2008. This will be undertaken in a separate process to this final decision.

The AER notes that its forecast GSL payments need to be adjusted from the draft decision for United Energy to account for this information and ensure that it can recover its efficient costs. The AER will take an average of the payments made from 2005–08 as forecast payments for the late connection GSL. This departs from the AER's draft decision, which used an average over the 2005–09 period.
United Energy's adjusted GSL payments allowance is shown in table 15.18. The AER has made the corresponding adjustment to United Energy's opex allowance.

Table 15.18 AER conclusion on GSL payments for United Energy ($, nominal)

GSL parameter	Forecast number	Forecast payments
15 minutes late for an appointment	30	592
Connections not made on agreed date total	116	11 380
Connections not made—1–4 day delay	102	8 005
Connections not made—5+ day delay	14	3 375
20 hours of interruptions	2 071	207 075
30 hours of interruptions	237	35 475
60 hours of interruptions	34	10 200
10 interruptions	61	6 050
15 interruptions	–	–
30 interruptions	–	–
24 momentary interruptions	–	–
36 momentary interruptions	–	–
Streetlights	18	184
Total		**270 956**

Source: AER analysis

Impact on worst served customers

The Minister expressed his concerns that the extent of GSL payments to the worst served customers under the national GSL scheme may not be consistent with that of the existing GSL scheme because of the differences in GSL obligation assessment criteria, in particular regarding the threshold levels on which major events are excluded from GSL payment. As the current GSL scheme and the associated exclusion criteria remains unchanged, the AER does not expect significant changes in the number of GSL payments to be made to the worst served customers.

As shown in table 15.19, the total forecast GSL payment for the 2011–15 regulatory control period is $5 820 769. This overall GSL payment amount is almost identical to that previously forecasted by the ESCV in 2005 for the 2006–10 regulatory period of $5 869 750.[222]

The AER's forecast amount is based on the 2005–09 actual GSL payments. As the actual payments for 2005–09 were almost the same as the original forecast, this would indicate that the levels of supply reliability and other customer services have not changed in a material manner in terms of GSL obligations from originally predicted. Hence, the targeted customers to be covered the GSL scheme for the 2011–15 regulatory control period are expected to be relatively unchanged from the 2006–10 regulatory period.

By way of comparison, based on the GSL payment quantities estimates provided in the DNSPs' initial regulatory proposals (tables 15.7 to 15.9 of the draft determination),[223] the AER estimated that the total overall GSL payments for the 2011–15 regulatory control period under the national GSL scheme is essentially similar to that of the ESCV scheme, at about four per cent less than the ESCV scheme. The AER also notes the major difference between the two GSL schemes being:

- there would be more 'less-affected' worst served customers (suffering between 12 and 20 hours of supply outage,[224] or more than 10 interruptions) receiving low supply reliability GSL payments under the national scheme than the ESCV scheme, but

- lower number of GSL payments to those 'more-affected' worst served customers—suffering more than 30 hours of supply outage, or more than 15 interruptions—under the national scheme.

15.6.16.5 AER conclusion

As required under clause 6.6.2(b)(2) of the NER, and clauses 2.1(c) and 6.1 of the STPIS, the AER will apply the GSL scheme specified in section 6 of the EDC and section 2.5 of the PLC.

The AER has had regard to the past performance of the Victorian DNSPs' networks and will apply the GSL forecasts as specified in the draft decision to CitiPower,

[222] ESCV, *2006–10 EDPR Final Decision Vol 1*, p.76.
[223] Adjusted for (1) SP AusNet's estimate was based on 3.2 beta MED exclusion threshold; and (2) United Energy did not provide estimated GSL payments under the national scheme.
[224] 18-20 hours for rural customers.

Powercor, JEN and SP AusNet.[225] The AER will apply a forecast that has been modified from the draft decision for United Energy. The AER will require United Energy to pay all relevant GSL payments in accordance with the EDC. The GSL payments forecasts that will apply in each year of the 2011–15 regulatory control period for Victorian DNSPs are outlined in table 15.19.

Table 15.19 AER final conclusion on GSL payments per annum ($, nominal)

DNSP	Total payment
CitiPower	15 470
Powercor	1 176 156
JEN	18 892
SP AusNet	4 339 295
United Energy	270 956
Total, all DNSPs	**5 820 769**

Source: AER analysis

15.6.17 Different time reference terms between the STPIS and revenue control formula

15.6.17.1 Victorian DNSP initial and revised regulatory proposals

In its initial regulatory proposal, JEN stated that in the AER's Framework and approach paper the AER had published:

> …certain component parts of its STPIS but as yet has not published a comprehensive S factor specification capable of inclusion in the WAPC.

JEN's revised regulatory proposal stated:

> The AER's draft decision does not specify how the S factor in the AER's proposed WAPC will be calculated. JEN requests that the AER publish its proposed S factor parameter specification for consultation. This is particularly important given that issues raised in the DNSPs' original proposals and summarised in the draft decision do not appear to have been addressed.[226]

The AER sought clarification from JEN regarding its concern about the calculation of the S factor in the proposed WAPC outlined in the draft decision.[227] In response, JEN stated that:

> …the AER's draft determination does not provide a standalone weighted average price cap (WAPC) in terms of how the S factor will incorporate annual STPIS price adjustments. Instead, it references the AER's November 2009 STPIS guideline (the STPIS guideline) which introduces discrepancies

225 AER, *Draft decision*, 2010, p. 688–693.
226 JEN, *Revised regulatory proposal*, p. 22.
227 AER, *email*, 1 September 2010.

> between parameter specifications contained in the draft determination and those in the guideline without any clear statement of which has precedence.
>
> JEN considers that including the full S factor specification in the determination would overcome these problems.
>
> The discrepancy between the AER's draft determination and the STPIS guideline relates to the different specification of regulatory years in the draft determination WAPC to that in the STPIS guideline.[228]

JEN contrasted the definition of the WAPC provided in the AER's draft determination with the definition provided in appendix C of the STPIS:

> In the draft determination, the year for which the calculation is being undertaken is defined as year 't'. In the STPIS guideline, the year for which the calculation is being undertaken is defined as year 't+1'…
>
> …JEN considers that the AER can and should avoid uncertainty in how the STPIS will apply by including the full St parameter specification for implementing the STPIS in the final determination in a manner that is consistent with the concepts and terminology used in the draft determination.

15.6.17.2 AER issues and considerations

The AER acknowledges JEN's concerns regarding the clarity of the STPIS application in the 2011–15 regulatory control period and the notational differences between the AER's STPIS and the WAPC formula included in its draft decision.

The AER's STPIS lists a number of forms of control to which the STPIS may be applied and provides general formulas for each. The Victorian DNSPs are subject to a weighted average price cap (WAPC), and as such, the STPIS will apply in the manner set out in formula 1C of appendix C of the STPIS.

Specifically, JEN has sought to clarify the interaction between the formulas in the AER's STPIS and the WAPC. For the avoidance of doubt, the actual service performance outcomes from 2011 will be incorporated into the 2013 WAPC formula and therefore impact on 2013 tariffs.

15.6.17.3 AER conclusion

The AER considers that the STPIS intends that actual service performance outcomes from 2011 will impact on 2013 tariffs and that the WAPC and S factor calculations should be applied in a manner to achieve this outcome.

The STPIS will apply to the Victorian DNSPs in the general form set out in formula 1C of appendix C of the STPIS.

The AER considers that the above clarification removes any ambiguity that may have arisen due to any notational duplication between the AER's STPIS and the WAPC formula in its draft decision. The AER does not consider that any adjustment to either formula is necessary.

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228 JEN, *email*, 7 September 2010.

15.6.18 Implementation of the S factor

The STPIS will apply to the Victorian DNSPs from the commencement of the 2011–15 regulatory control period. As the 2011 performance will only be available in the first quarter of 2012, the S factor result of 2011 will be incorporated into the Victorian DNSPs' distribution tariff models for 2013 in their tariff approval submissions at the end of 2012.

15.6.18.1 AER draft decision

In the AER's draft decision it noted that:

> … for the purpose of the distribution tariff calculation, the S_t factor applied to the Weighted Average Price Cap formula for 2011 and 2012 will be zero.[229]

15.6.18.2 AER conclusion

There were no comments in the Victorian DNSPs' revised regulatory proposals, nor submissions, on this matter. The AER has not changed its view from the draft decision. The S factor for 2011 and 2012 will be set at zero per cent

15.6.19 Response to submissions

This section responds to submissions which do not directly relate to issues proposed in the Victorian DNSPs revised regulatory proposals.

15.6.19.1 Increased revenue at risk level for SP AusNet

The AER considers that it has adequately addressed the EUCV's concern that the AER's draft decision revenue cap of 7 per cent imposes a higher financial risk to consumers than is warranted.[230] The AER considered that an increase in SP AusNet's revenue at risk was warranted in the draft decision. The AER considered that SP AusNet's SAIDI performance has historically been below the average of the other Victorian DNSPs and therefore the AER was willing to increase the incentive to improve it.[231] The AER understands that increasing the revenue at risk increases the financial risk to consumers, however, increased tariffs only arise from improvements in supply reliability beyond the targets. In addition, a 7 per cent cap on revenue at risk also allows for the possibility for greater reductions in tariffs, should supply reliability deteriorate. In its draft decision the AER noted that:

> …the AER considers that a 7 per cent cap on revenue at risk is an appropriate and measured increase in SP AusNet's revenue at risk. This is a symmetric increase in the cap on revenue at risk so SP AusNet will be subject to both greater upside and downside revenue at risk. This proportion balances the financial incentive to improve performance and the risk to SP AusNet and customers of large tariff fluctuations and the willingness of end users to pay for service improvements. [232]

229 AER, *Draft decision*, 2010, p. 683.
230 EUCV, *Submission to the AER*, 19 August 2010, p. 45
231 AER, *Draft decision*, 2010, p. 639.
232 Ibid., p. 640.

15.6.19.2 Including quality of supply measures in the S factor

The EUAA expressed its desire for the AER to include a quality of supply parameter in the STPIS and submitted that the AER address this shortcoming in the final determination. [233] This submission relates to the design of the STPIS which is not currently under review. The AER noted in its draft decision that:

> Regarding submissions proposing to add a quality of supply parameter to the STPIS, the AER notes that currently the monitoring of supply quality covers limited areas of each DNSP's network.[234] Hence, the existing quality of supply data may not be suitable for the purpose of the STPIS. However, the AER notes that the Victorian Government has mandated a complete rollout of smart meters to replace all existing energy meters by 2013. The new smart meters will have the capability to monitor steady-state voltage as a factor of supply quality. The AER will consider whether to include quality of supply as a performance measure when it reviews the STPIS in the future.[235]

15.6.19.3 Low performance feeders

EUCV supports the continuation and expansion of the service incentives. EUCV noted that poor performing feeders should be targeted by the AER in future reviews.[236] The AER agrees that the STPIS is an important feature of the AER's regulation of DNSPs to ensure that increases in operational and capital efficiency are not achieved at the expense of a deterioration in service performance for customers. Whilst poor performing feeders are not specifically targeted by the STPIS, the AER notes that the worst served customers are targeted by the GSL scheme. The AER also reports on the worst performing feeders and the worst served customers in its annual performance report to increase transparency. The AER is expanding transparency and accountability in this area with the introduction of an outcomes monitoring framework as discussed in chapter 21.

15.7 AER conclusion

This chapter sets out the AER's considerations and reasons for its final decision as to how the STPIS is to be applied to the Victorian DNSPs in the 2011–15 regulatory control period.

In making its constituent decision pursuant to clause 6.12.1(9) of the NER, the AER has had regard to the requirements under clause 6.6.2(b) of NER and considered all submissions made on the STPIS pursuant to clause 6.10.1 of the NER. The AER has also had regard to the revenue and pricing principles where appropriate. The AER's decision on how the STPIS is to apply to the Victorian DNSPs can also be found in the determination documents for CitiPower, Powercor, JEN, SP AusNet and

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233 EUAA, *Submission to the AER*, 19 August 2010, p. 37.

234 AER, *Victorian Electricity Distribution Businesses, Comparative Performance Report 2008*, November 2009, p. 52. Currently, DNSPs monitor quality of supply at each zone substation and at the far end of one distribution feeder supplied from each zone substation. Under the 2006–10 EDPR, the two predominantly rural distributors, Powercor and SP AusNet, were funded to install additional sophisticated voltage monitoring equipment (27 locations for Powercor and 17 for SP AusNet).

235 AER, D*raft decision*, p. 635.

236 EUCV, *Submission to the AER*, 19 August 2010, p. 44.

United Energy. Consistent with clause 2.1(d) of the STPIS, the AER's conclusions which form the basis of its constituent decision are set out below:

- The AER concludes that it will apply the SAIDI, SAIFI and MAIFI reliability parameters to the Victorian DNSPs, as set out in the STPIS. For transitional reasons, the AER will apply the ESCV's definition of MAIFI discussed at section 15.6.12 of this chapter and section 15.7.8 of the draft decision.

- Having regard to clause 6.6.2(b)(3)(i) and (vi) of the NER, the AER has concluded to apply the caps on revenue at risk as set out in table 15.20.

- Having regard to clause 6.6.2(b)(3)(vi) of the NER the AER concludes that it will apply the incentive rates at table 15.21 to the reliability and customer service parameters consistent with methodology set out at sections 3.2.2 and 5.3.2(a)(1) of the STPIS respectively. The values of customer reliability to be applied in accordance with clause 3.2.2(b) and appendix B of the STPIS are set out in table 15.22

- The AER will segment the reliability parameters by network type in accordance with the STPIS and the performance target to apply to each applicable parameter in every regulatory year of the regulatory control period are set out in table 15.23. In establishing these targets the AER has had regard to the Victorian DNSPs' past performance in accordance with clause 6.6.2(b)(3)(iii) of the NER.

- The AER will close out the ESCV S factor scheme by applying the methodology set out in section 15.6.6 of this final decision. The adjustments to the building blocks are set out in table 15.24.

- Having regard to clauses 6.6.2(b)(2) and 6.6.2(b)(3)(ii), and consistent with section 6.1(a) of the STPIS, the AER concludes that it is bound to apply the existing Victorian GSL scheme under section 6 of the Electricity Distribution Code and section 2.5 of the Public Lighting Code.

- The AER concludes that it will allow the forecast GSL opex allowance pursuant to clause 6.5.6(a)(2) of the NER as set out in table 15.25.

- The MED threshold is to be calculated in accordance with section 3.3 of the STPIS and is to be based on the beta values set out in table 15.26.

Table 15.20 AER conclusion on cap on revenue at risk (per cent)

DNSPs	Cap on revenue at risk
CitiPower	±5
Powercor	±5
JEN	±5
SP AusNet	±7
United Energy	±5

Source: AER analysis.

Table 15.21 AER conclusion on incentive rates for SAIDI, SAIFI, MAIFI and the telephone answering parameter (per cent per unit)

	CitiPower	JEN	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI	0.1259	–	–	–	–
SAIFI	6.7499	–	–	–	–
MAIFI	0.5400	–	–	–	–
Urban	–	–	–	–	–
SAIDI	0.0733	0.1054	0.0474	0.0334	0.1088
SAIFI	3.7572	6.6017	3.1881	2.4242	6.8707
MAIFI	0.3006	0.5281	0.2550	0.1939	0.5497
Rural short	–	–	–	–	–
SAIDI	–	0.0046	0.0274	0.0287	0.0122
SAIFI	–	0.2949	2.1849	2.4696	0.7572
MAIFI	–	0.0236	0.1748	0.1976	0.0606
Rural long	–	–	–	–	–
SAIDI	–	–	0.0238	0.0139	–
SAIFI	–	–	2.3799	1.1687	–
MAIFI	–	–	0.1904	0.0935	–
Telephone answering parameter	–0.040	–0.040	–0.040	–0.040	–0.040

Source: AER analysis.

Table 15.22 AER conclusion on the value of customer reliability ($, MWh)

	Value of customer reliability
CBD	101 734
Urban	50 867
Rural short	50 867
Rural long	50 867

Table 15.23 AER conclusion—performance targets for SAIDI, SAIFI, MAIFI and the telephone answering parameter

	CitiPower	JEN	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI (average minutes)	11.271	–	–	–	–
SAIFI (average interruptions)	0.186	–	–	–	–
MAIFI (average interruptions)	0.026	–	–	–	–
Urban	–	–	–	–	–
SAIDI (average minutes)	22.360	68.498	82.467	101.803	55.085
SAIFI (average interruptions)	0.450	1.127	1.263	1.448	0.899
MAIFI (average interruptions)	0.175	0.776	1.412	2.512	1.074
Rural short	–	–	–	–	–
SAIDI (average minutes)	–	153.150	114.807	208.542	99.151
SAIFI (average interruptions)	–	2.588	1.565	2.632	1.742
MAIFI (average interruptions)	–	1.940	2.881	5.409	2.122
Rural long	–	–	–	–	–
SAIDI (average minutes)	–	–	233.759	256.578	–
SAIFI (average interruptions)	–	–	2.540	3.317	–
MAIFI (average interruptions)	–	–	6.535	8.924	–
Telephone answering parameter (per cent)	71.52	61.16	64.84	82.31	62.83

Source: AER analysis.

Table 15.24 AER conclusion on the building blocks resulting from the ESCV S factor close out ($, million)

	2011	2012	2013	2014	2015
CitiPower	– 2.19	– 4.50	– 3.33	– 0.33	– 3.54
Powercor	– 5.95	– 20.94	– 5.22	– 0.31	0.82
JEN	5.46	0.92	– 0.20	– 0.19	– 9.75
SP AusNet	40.22	20.21	– 7.04	– 1.59	– 78.87
United Energy	– 4.80	– 4.80	– 6.21	– 6.15	– 10.83

Source: AER analysis.

Table 15.25 AER conclusion on annual total GSL payments ($, nominal)

DNSP	AER draft decision
CitiPower	15 470
Powercor	1 176 156
JEN	18 892
SP AusNet	4 339 295
United Energy	270 956

Source: AER analysis.

Table 15.26 AER conclusion on MED threshold to be set X beta from the mean

MED thresholds	AER draft decision
CitiPower	2.5
Powercor	2.8
JEN	2.5
SP AusNet	2.8
United Energy	2.5

Source: AER analysis.

16 Cost pass throughs

16.1 Introduction

Clause 6.12.1(14) of the NER requires the AER to make a constituent decision on the additional pass through events (nominated events) that are to apply for the regulatory control period. These are in addition to the prescribed events defined in Chapter 10 of the NER. This chapter sets out the AER's consideration of additional nominated pass through events for the Victorian DNSPs during the forthcoming 2011–15 regulatory control period.

16.2 Regulatory requirements

An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks appropriately and incurs additional costs, it would be expected to bear those costs. However, the NER pass through provisions recognise that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs.

The NER specifies certain pass through events that are applicable to all distribution determinations.[1]These are:

- a regulatory change event
- a service standard event
- a tax change event
- a terrorism event.

The chapter 10 definition of pass through event provides (in addition to the four events listed above) that 'An event nominated in a distribution determination as a pass through event is a pass through event for the determination'. This chapter considers which pass through events will constitute additional (or 'nominated') pass through events for the 2011–2015 regulatory control period.

The NER does not provide any specific criteria that the AER is to have regard to in assessing proposed additional pass through events. Accordingly, the AER has developed certain criteria for this purpose, and in developing these criteria has had regard to the National Electricity Objective (NEO) and the revenue and pricing principles contained in the National Electricity Law (NEL).

The AER has a broad discretion in respect of its decision on the additional pass through events that are to apply in a regulatory control period. It appears that neither the Chapter 10 definition of pass through event nor clause 6.12.1(14) limits the AER's discretion. Support for this position is derived from clause 6.12.3 of the NER which sets out the extent of the AER's discretion in making distribution determinations. Clause 6.12.3(a) states that:

1 NER, Chapter 10.

> Subject to this clause and other provisions of this chapter 6 explicitly negating or limiting the AER's discretion, the AER has a discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal.

While clause 6.12.3(f) limits the operation of clause 6.12.3(a), the limit only applies to the AER's refusal to approve an amount or value. A pass through event cannot properly be described as an amount or a value. Accordingly, in exercising its discretion the AER had regard to the National Electricity Objective (NEO) and the Revenue and Pricing Principles (RPP).

16.3 AER draft decision

The AER's draft decision for the Victorian DNSPs set out criteria for the assessment of proposed pass through events. The AER developed these criteria with regard to the NEO in s. 7 of the National Electricity Law (NEL) and the Revenue and Pricing Principles (RPP) contained in s. 7A of the NEL.

These criteria were:

- the event is not already provided for:
  - in the defined event definitions in the NER (and does not conflict or undermine the events defined in the NER)
  - through the opex allowance (e.g. the insurance or self insurance components)
  - through the WACC (events which affect the market generally and not just the provider are systematic risk and already compensated through the WACC), or
  - through any other mechanism or allowance
- the event is foreseeable—in that the nature or type of event can be clearly identified
- the event is uncontrollable—in that a prudent service provider through its actions could not have reasonably prevented the event from occurring or substantially mitigated the cost impact of the event
- the event cannot be self-insured because a self insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic
- the party who is in the best position to manage the risk is bearing the risk
- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.[2]

The AER considered that these principles were consistent with the NEL, particularly the NEO and RPP.

[2] AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 716–717.

The AER's treatment of pass through events, in accordance with s. 7 of the NEL, seeks to promote the long term interests of consumers by ensuring that prices are reflective of efficient network operating costs. It also seeks to ensure that, to the extent that extra costs are passed through in the regulatory control period, those costs are beyond the control of the DNSP. The reliability and security of electricity supply on the network is also ensured by allowing costs incurred through the inclusion of the 'natural disaster event'. For example, costs associated with natural disaster events, if not passed through, could potentially undermine the financial viability of the DNSP and threaten the security of supply on the network.

The AER also considered that its approach is consistent with the RPP contained in s. 7A of the NEL. In particular, ss. 7A(2)(a) and (b) of the NEL provide that DNSPs should be given a reasonable opportunity to be able to recover at least the efficient costs the operator incurs in providing direct control network services and complying with regulatory obligations or requirements. The AER notes that costs that are uncontrollable (or controllable but of a high magnitude) are only passed through where they are not recoverable elsewhere in the regulatory regime and to do otherwise would allow DNSPs to recover above the efficient costs of delivering direct control services. The AER acknowledged the need for DNSPs to recover the efficient costs associated with meeting regulatory obligations or requirements that are not recovered elsewhere. The AER considered that the appropriate mechanism for the recovery of these costs is through the pass through events contained in the NER.

- In relation to s. 7A(3) of the NEL, the AER noted that DNSPs should be provided with incentives to efficiently provide network services. To promote this objective, the AER included in its pass through event assessment criteria, the requirement that pass through events are beyond the control of the DNSPs. The AER considered that limiting pass throughs to events that are beyond the control of the DNSPs will not affect the incentives for the DNSP to mitigate (and reduce the cost impact of) these events given they are beyond the DNSP's control. In contrast, allowing the costs associated with events that are within the control of the DNSPs as a pass through may undermine the incentives of the regulatory regime. Accordingly, by restricting pass through events that are beyond the control of the DNSPs, the AER sought to ensure that costs which can be mitigated by the DNSP are not being passed through to consumers. This is also consistent with the AER's view that the risk associated with an event should lie with the party who is best placed to manage that risk.

The AER did not, in its draft decision,[3] apply the general nominated pass through event (which had been included in the South Australia/Queensland and New South Wales/ACT distribution determinations). The AER instead included a natural disaster event which was intended to capture major uncontrollable costs of a high magnitude (which was the intent of the general nominated pass through event).[4]

3 AER, *Draft Decision*, pp. 718–720.
4 See, for example, the AER's final distribution determination for NSW DNSPs, p. 278. This document can be found at www.aer.gov.au

The AER also determined a materiality threshold of one per cent of the smoothed forecast revenue in each of the years of the regulatory control period for all pass through events.[5]

The AER assessed the Victorian DNSPs' proposed pass through events against the criteria set out above. The AER considered that several pass through events proposed by the Victorian DNSPs were likely to be captured by the definitions of terrorism event, service standard event, regulatory change event or tax change event contained in chapter 10 of the NER. The AER rejected the following proposed pass through events on that basis that these events are likely to be either service standard events, regulatory change events, or tax change events:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework event (proposed by CitiPower and Powercor)
- a change in safety regulations introduced by the Energy Safe Victoria (ESV) event (proposed by CitiPower and Powercor)
- a changes in exposure limits event (proposed by CitiPower and Powercor)
- a recommendations arising from the Royal Commission into Victorian Bushfires event (proposed by Powercor)
- an Emissions Trading Scheme (ETS) event (proposed by CitiPower, Powercor, JEN and United Energy) and
- a Carbon Pollution Reduction Scheme (CPRS) event (proposed by SP AusNet)
- a transfer of customer regulation to the national regulatory framework event (proposed by United Energy)
- an introduction of new regulatory obligations for vegetation management around powerlines event (proposed by United Energy)
- a changes to bushfire mitigation framework event (proposed by United Energy)
- a national broadband network event (proposed by United Energy)
- a change in corporate income tax event (proposed by United Energy)
- an AEMO fees and charges event (proposed by CitiPower and Powercor).[6]

Further, the AER rejected the change in corporate income tax event (proposed by United Energy). United Energy proposed this event on the grounds that the NER defined tax change event explicitly excluded changes in corporate income tax. The AER agreed that the tax change event did exclude corporate income tax as it does not come within the definition of 'relevant tax' in Chapter 10 of the NER.[7] The AER

5 AER, *Draft Decision,* pp. 713–715.
6 ibid., pp. 708–710.
7 ibid., p.710.

considered that the inclusion of such an event would undermine the NER. The definition of tax change event in the NER explicitly excludes changes to corporate income tax.[8]

The AER also rejected the following proposed pass through events:

- a climate change assumptions being materially wrong event (proposed by United Energy), as it could not be clearly identified and defined in advance and it undermines the incentive properties in the regime. The AER also considered that it was not uncontrollable and not of a high magnitude.

- a forced load shedding event (proposed by SP AusNet) as this would undermine the incentive properties in the regulatory regime. The AER also considered that it was not uncontrollable and not of a high magnitude. The AER also considered that this event did not relate to a cost increase or decrease incurred by the DNSPs. Rather, it would merely compensate the DNSP for lost revenue based on reduced sales of energy.

- wind farm connection costs (proposed by Powercor). The AER considered that these costs would be recovered elsewhere in the regulatory regime, that is, through the arrangements in chapter 5 of the NER for new connections.

- a network extension for remote generation event (proposed by Powercor). The AER considered that these costs would be recovered elsewhere in the regulatory regime, that is, through normal connection charges associated with embedded generation.

- an s-factor payout event (proposed by SP AusNet), as this did not relate to costs but instead, revenue adjustments.

- a premium feed in tariff event (proposed by SP AusNet), as this was dealt with through a rule change being considered by the AEMC.

- a financial failure of a retailer event (proposed by CitiPower, Powercor, JEN, and United Energy). The AER considered that this could be recovered elsewhere in the regulatory regime, namely through the prudential requirements outlined in cl. 6.21.1 of the NER).

- an asbestos compensation event (proposed by JEN). The AER considered that this was a risk potentially faced by all businesses in the market, and that it is the responsibility of a prudent business to undertake due diligence in relation to such risks. Any consequent risk should be borne by shareholders, not network users.

- a force majeure event (proposed by JEN and United Energy). The AER considered that most events of this nature would be captured in the 'natural disaster' pass through event.[9]

8 ibid., pp. 710–711.

9 ibid, pp. 722–724. The natural disaster event was proposed by the AER rather than the Victorian DNSPs.

The AER accepted the following proposed nominated pass through events in the draft decision:

- a declared retailer of last resort (ROLR) event (proposed by JEN, CitiPower, Powercor and United Energy).
- an insurer credit risk event (proposed by JEN). The AER amended the definition of this event for clarity.
- an insurance event/legal liability above insurance cap event (proposed by SP AusNet and JEN respectively). Whilst these were proposed separately, the AER considered that they were similar in scope, and grouped these together. The AER then amended the definition for clarity, and removed specific references to JEN so that it could be applied to all Victorian DNSPs.
- The AER also included a natural disaster event (which was not proposed by the Victorian DNSPs).[10]

16.4 Victorian DNSP revised regulatory proposals

16.4.1 Materiality threshold

JEN considered that the AER had incorrectly assumed that it had the legal power to set a materiality threshold in a distribution determination.[11]

JEN noted that even if the AER were empowered to set a materiality threshold, the one percent of annual smoothed revenue threshold conflicts with the NEO and the RPP, particularly the RPP set out in ss. 7A(2) and 7A(3) of the NEL.[12]

United Energy also stated that the AER's position was in conflict with the NEO. It stated that a one percent threshold would preclude United Energy from recovering its costs.[13]

SP AusNet also submitted that the threshold was inconsistent with the NEO and that such a threshold 'does not provide SP AusNet with a reasonable opportunity to recover at least the efficient costs the operator incurs in ... providing direct control services'. SP AusNet considers that by adopting a threshold that exceeds the administrative costs associated with assessing cost pass through applications, businesses may be incentivised to “over insure” to reduce their overall financial risk.[14]

CitiPower and Powercor submitted that the one percent materiality threshold was too high, stating that:

10 AER, *Draft decision*, pp. 726–728.
11 JEN, *Jemena Electricity Networks (Vic) Ltd, Revised regulatory proposal*, July 2010, p. 294.
12 ibid., pp. 294–295
13 United Energy, *Revised regulatory proposal*, p. 334.
14 SP AusNet, *Electricity Distribution Price Review, 2011–2015 revised regulatory proposal*, July 2010, p. 354. JEN also made a similar point on the incentive to over insure, see JEN, *Revised regulatory proposal*, p. 295.

- the threshold is inconsistent with the AER's reasoning in rejecting the materiality threshold applied to specific nominated pass through events in recent distribution decisions which seek to align the threshold with the ordinary meaning of 'materially.'

- the AER had regard to ensuring consistency with transmission. No reasonable decision maker would make a determination in respect of Victorian distribution determination which seeks to ensure consistency with transmission regulation, but which is not consistent with its previous distribution determinations.

- the AER justified the threshold as the threshold applied to general nominated pass through events in previous distribution determinations, however, here the AER is seeking to apply the threshold to specific nominated pass through events. It did not apply this threshold to specific nominated pass through events in previous distribution determinations, nor did jurisdictional electricity regulators in other States in their previous price determinations.

- the threshold is onerous and leads to perverse outcomes. The imposition of the threshold result in a fundamental reassignment of risk between DNSPs and their customers, which increased the risks the DNSPs would have to be compensated for through regulated revenues.[15]

16.4.2 NER defined pass through events

CitiPower, Powercor, JEN and United Energy all proposed that the AER should confirm that it would treat certain events as NER prescribed pass through events.[16] In proposing this, the DNSPs referred to a list of pass through events which the AER rejected in its draft decision on the grounds that they would likely fall within the definition of either one of the NER prescribed events.[17]

United Energy asserted that a failure to nominate these events would result in uncertainty for the DNSPs.[18]

JEN sought confirmation that the emissions trading scheme (ETS) pass through event would fall into either the 'service standard event' or 'regulatory change event', defined by the NER.[19] CitiPower and Powercor sought confirmation as to whether the following events would be 'service standard events' or 'regulatory change events':

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework

- changes to safety regulations introduced by the ESV

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15 CitiPower, Revised regulatory proposal, 2011 to 2015, July 2010, p. 414 Powercor, *Revised regulatory proposal,* 2011 to 2015, July 2010, p. 414.

16 JEN, *Revised regulatory proposal*, pp. 295; CitiPower, *Revised regulatory proposal*, pp. 408–409; Powercor, *Revised regulatory proposal*, pp. 408–409; United Energy, *Revised regulatory proposal*, p. 328.

17 As defined in ch. 10 of the NER.

18 United Energy, *Revised regulatory proposal,* July 2010, p. 328.

19 JEN, *Revised regulatory proposal*, p. 295.

- changes to exposure limits
- an emissions trading scheme event
- an AEMO fees and charges event.[20]

16.4.3 Rejection of nominated pass through events

16.4.3.1 AER's rejection of 'Bushfire Royal Commission recommendations' event

JEN, Powercor, SP AusNet and United Energy all submitted that the AER should not have rejected this event.[21] The DNSPs stated that it is unclear what form the recommendations would take and what changes the DNSPs would need to implement to comply with any recommendations. The DNSPs stated that it was uncertain as to whether or not this would fall within the regulatory change event or service standard event definition. Therefore, the AER should permit this as a nominated event.[22]

16.4.3.2 AER's rejection of financial failure of a retailer event

All five Victorian DNSPs disagreed with the AER's rejection of this event. They disputed the AER's assertion that prudential requirements could be sought under cl. 6.21 of the NER.[23] The DNSPs cited the default Use of System Agreement (UoSA), which their licences compel them to implement. The credit support arrangements therein align with the ESC's decision on credit support arrangements in the 2006–2010 Electricity Distribution Price Review (EDPR). The DNSPs submitted that these credit support arrangements do not fully compensate the provider for losses incurred due to retailer failure. United Energy stated that the AER would have to amend the UoSA if it intended to maintain its rejection of 'financial failure' event.[24] CitiPower and Powercor both stated that such a rejection would transfer risk from customers to DNSPs and that no additional compensation for this risk was provided (e.g. through the WACC, or opex/capex allowances).[25] Further, CitiPower and Powercor both proposed a materiality threshold of zero to apply to this event.[26]

16.4.3.3 AER's rejection of force majeure event

JEN submitted that this event should be included to address events which do not fall within the 'natural disaster' event. Specifically, JEN cited sabotage, war and riot and other 'human' activities, stating that these would not be recovered by the natural

20 CitiPower, *Revised regulatory proposal*, p. 408; Powercor, *Revised regulatory proposal*, p. 407.
21 JEN, *Revised regulatory proposal.* pp. 302–303; Powercor, *Revised regulatory proposal*, pp. 408–409; SP AusNet, *Revised regulatory proposal.* pp. 353–354; United Energy, *Revised regulatory proposal.* p. 329.
22 ibid
23 CitiPower, *Revised regulatory proposal.* pp. 410–411; JEN, *Revised regulatory proposal.* pp. 299–300; Powercor, *Revised regulatory proposal*, pp. 410–411; SP AusNet, *Revised regulatory proposal.* pp. 353–354; United Energy, *Revised regulatory proposal.* p. 329.
24 United Energy, *Revised regulatory proposal.* p. 329.
25 CitiPower, *Revised regulatory proposal.* pp. 410–411; Powercor, *Revised regulatory proposal.* pp. 410–411.
26 CitiPower, *Revised regulatory proposal.* pp. 420–422; Powercor, *Revised regulatory proposal.* pp. 420–422.

disaster event (whilst acknowledging there could be potential overlap between these two events).[27]

16.4.3.4 AER's rejection of asbestos compensation event

JEN submitted that the AER's rejection of this event conflicts with the NSW and ACT distribution determinations published by the AER. JEN considered that the AER's rationale for rejecting this event was unclear. JEN stated that the AER has misdirected itself by incorrectly considering whether businesses generally face a particular risk. JEN noted that a more appropriate consideration was whether or not permitting the pass through was consistent with the NEO and RPP (JEN asserts that this pass through event is consistent with both).[28]

16.4.4 Rejection of general nominated pass through event

CitiPower and Powercor did not accept the AER's rejection of the general pass through event. They disagreed with the AER's revised view of ‘forseeability’ since the previous distribution determinations, stating that this revised definition had now caused the AER to reject the general pass through event. CitiPower and Powercor further stated that the AER's pass through guideline for transmission is irrelevant, and that the NER recognises that the treatment of pass throughs in transmission and distribution should be different.[29]

United Energy also proposed that the AER accept the general pass through event for the Victorian DNSPs, noting that failing to do so is inconsistent with other jurisdictions. Further, requiring events to be defined tightly in advance hinders the NEO and places too much weight on the 'uncontrollability' element of pass throughs.[30]

16.4.5 Transmission related costs event

CitiPower, Powercor, JEN and United Energy all proposed the inclusion of a transmission related costs event in the event that these costs could not be recovered through proposed variances to the weighted average price cap (WAPC) formula (see chapter 4 for further discussion on the proposed amendments).[31] CitiPower and Powercor proposed that this event carry a materiality threshold of zero.[32] These costs include avoided transmission use of system (TUOS) charges, inter DNSP payments and transmission connection costs.

16.4.6 Definitions of nominated pass through events

16.4.6.1 Insurance event

JEN and SP AusNet both raised issues with the AER's definition of insurance event. JEN stated:

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27 JEN, *Revised regulatory proposal.* pp. 295–296.
28 JEN, *Revised regulatory proposal.* p. 301.
29 CitiPower, *Revised regulatory proposal.* pp. 408–409; Powercor, *Revised regulatory proposal.* pp. 409–411.
30 United Energy, *Revised regulatory proposal,* pp. 326–328.
31 CitiPower, *Revised regulatory proposal.* p. 413; JEN, *Revised regulatory proposal.* pp. 310–311; Powercor, *Revised regulatory proposal.* pp. 413–414; United Energy, *Revised regulatory proposal.* p. 330.
32 CitiPower, *Revised regulatory proposal.* p. 422; Powercor, *Revised regulatory proposal.* pp. 423–424.

> JEN acknowledges the AER's concerns in terms of providing service providers with an appropriate incentive to mitigate and minimise the costs arising in connection with any pass through event. The mere fact that service providers may pass through costs should not provide service providers with an incentive not to operate in a prudent and efficient manner. However, JEN notes that the consideration of whether a DNSP has taken appropriate action to mitigate the harm arising from a pass through event is appropriately built into the AER's assessment of the relevant costs that may be passed through (see clause 6.6.1(j) of the Rules). Therefore, a DNSP is incentivised to minimise the costs incurred beyond an insurance cap. JEN maintains that the drafting of the insurance event in its proposal is appropriate and the AER has not provided any reasons as to why JEN's drafting should not be adopted.[33]

SP AusNet stated:

> SP AusNet considers that the exclusion provisions contained in the above definition – particularly the reference to "the DNSP's negligence, fault, lack of care" – in effect, negate the entire pass through event clause. In particular, the AER must understand that liability policies are in fact designed to cover claims where SP AusNet is deemed to be negligent, therefore, but for the limits within a policy, events where SP AusNet is deemed to be negligent would in fact be covered by SP AusNet's insurance policies …a claim against SP AusNet would be unlikely to be successful if the opposing party was unable to establish wrong doing or negligence. Hence in this case, SP AusNet's insurance coverage would not be invoked, and therefore, the pass through provision would not be invoked either. Notwithstanding this, it is noted that an insurance policy would not cover an illegal or grossly reckless act or omission, therefore, SP AusNet acknowledges and agrees that it is entirely reasonable that the AER should not allow a pass through for liability arising from any such act or omission of this nature.[34]

16.4.6.2 Insurer credit risk event

SP AusNet raised concerns with the definition of this event, stating that it was unclear from the AER's draft decision.[35]

16.4.7 AER's rejection of the Electrical Safety Management Scheme (ESMS) step change

CitiPower and Powercor both noted that this step change was rejected in the AER's draft decision and proposed this as a pass through event.[36] United Energy also proposed this event be included as a nominated pass through.[37]

16.5 Submissions

The AER also received several submissions on pass through events. These were from:

- The Department of Primary Industries—Victoria (DPI)
- The Energy Users Coalition of Victoria (EUCV)

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33 JEN, *Revised regulatory proposal.* pp. 301–302.

34 SP AusNet, *Revised regulatory proposal*, pp. 350–351.

35 ibid., pp. 351–352.

36 CitiPower, *Revised regulatory proposal,* pp. 412–41; Powercor, *Revised regulatory proposal.* pp. 412–413.

37 United Energy, *Revised regulatory proposal*, p. 332.

- JEN
- EnergyAustralia
- The Hon. Peter Batchelor, Minister for Energy and Resources (Victoria)
- CitiPower/Powercor
- Energy Users Association of Australia (EUAA)
- Origin Energy
- Victorian Council of Social Services (VCOSS)

The Minister for Energy and Resources submitted that the AER had taken too narrow an interpretation of a regulatory change event and that this would prevent Victorian DNSPs' from recovering costs associated with new regulatory obligations. The submission stated that:

> The AER thus accepted United Energy's argument that a regulatory change event did not include new regulatory obligations or requirements, which argument was based on a comparison of the definitions of "regulatory change event" and "tax change event" in Chapter 10 of the NER.
>
> However that comparison does not involve like for like. The definition of "tax change event" does not pick up the definition of "regulatory obligation or requirement" and it is for that reason, as well as the necessity to make the definition work with clause 6.6.1(j)(6) of the NER (which refers to countervailing taxes being imposed or removed), that the definition refers not only to change but also to imposition and removal of taxes. Accordingly the comparison is not a valid one. Further, United Energy's interpretation is inconsistent with the intent of the NER and limits a jurisdiction's ability to introduce new legislation or regulations that change the regulatory obligations of DNSPs. It is also inconsistent with a purposive interpretation of the NEL and NER. This is not in the long term interests of consumers, particularly if a regulatory obligation or requirement is removed thus reducing the costs of providing distribution services, resulting in a negative pass through event.[38]

EnergyAustralia expressed concern with the AER's materiality threshold, noting that it was inconsistent with thresholds in previous distribution determinations. It noted that the NER provides for the word 'materially' to be given its ordinary meaning. EnergyAustralia further noted:

> It was clearly the intention of the MCE that Distribution Rules depart from the Transmission Rules where appropriate or alternatively Distribution Rules are not required to be the same as Transmission Rules in all aspects. We consider that the meaning of the term ‘materially’ must therefore be interpreted based on its ‘ordinary meaning’ in the context of pass through provisions applicable to a DNSP.[39]

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[38] The Hon. Peter Batchelor, Minister for Energy and Resources, *Submission on the Victorian DNSPS regulatory proposals for 2011–2015*, August 2010, p. 11–12.

[39] EnergyAustralia, *EnergyAustralia’s submission on AER’s draft regulatory determination for Victorian distributors*, August 2010, pp. 17–18.

EnergyAustralia further noted that the Oxford dictionary defines material as:

> essential or relevant: evidence material to the case[40]

EnergyAustralia noted that the AER, whilst having broad discretion, still needed to align its materiality threshold with the RPP. EnergyAustralia noted:

- the fact that the NER differentiates between the meaning of materiality for transmission and the meaning of materiality for other purposes
- the importance of the interaction between the allowance for forecast operating and capital expenditure and the level of the threshold applied.[41]

EnergyAustralia also noted:

> Unless there is a provision or allowance included, the forecast costs at the time of the regulatory determination will be understated because at the time of submission of the regulatory proposals, the timing and/or cost impacts of new or uncertain events could not be reasonably forecast. We note that this has relevance for the AER's recent approach to assessing self insurance costs. The AER considered that certain self insurance items would be pass through events, and therefore the efficient costs can be recovered if the event occurs. At the same time, the AER has moved to a 1 per cent materiality threshold for all pass through events. Therefore the recovery of costs needs to be catered in the forecast allowance or pass through arrangements.[42]

The EUCV raised concerns with the AER's definition of the insurance pass through event.

> The drafting of the AER proposed pass through could allow the DB to insure for a much lower amount than needed, and by doing so would reduce its opex with the opex saving being retained by the DB. Should there be a claim which results in higher costs to the DB in a future regulatory determination, then the pass through as currently drafted would allow the DB to pass onto consumers the over-run in costs.[43]

The EUCV also noted the Victorian DNSPs' submission that the pass through regime does not allow the recovery of transmission costs. The EUCV noted:

> transmission costs do vary significantly year on year, most commonly as a result of the allocation of the inter-regional surplus residue. The EUCV accepts the principle that actual transmission costs they incur on behalf of their customers should be recovered in full by them from their customers.[44]

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40 ibid., p. 18.
41 ibid.
42 ibid.
43 EUCV, *Victorian Electricity Distribution Revenue Reset, AER Draft Decisions And Revised Regulatory Proposals on CitiPower, Jemena, Powercor, SP AusNet and United Energy Applications*, August 2010, p. 56.
44 ibid.

JEN made two further submissions. The first dealt with the AER's rejection of the bushfire pass through event. JEN stated:

> JEN believes that the 2009 Bushfires Royal Commission (Royal Commission) recommendations, and the current high degree of uncertainty as to how and when the Victorian Government will adopt them, reinforce the need for a specific bushfire pass through event. … JEN requested that the AER confirm in its final determination that Powercor's proposed 'bushfire event' falls within either the 'regulatory change event' or 'service standard event' scope. If the AER is unable to do so, the AER should treat the 'bushfire event' as specified by JEN in its revised regulatory proposal as a nominated pass through event. The Royal Commission conducted an extensive investigation into the causes of, the preparation for, the response to, and the impact of, the fires that burned throughout Victoria in late January and February 2009. [45]

JEN further noted that:

> Adoption of Recommendation 27 could have the greatest impact on JEN's costs. In it the Royal Commission recommends the replacement of all:
>
> - single wire earth return (SWER) power lines in Victoria with aerial bundled cable, underground cabling or other technology in the areas of highest bushfire risk within 10 years
>
> - 22 kilovolt (kV) distribution feeders with aerial bundled cable, underground cabling or other technology as the feeders reach the end of their engineering lives in the areas of highest bushfire risk.[46]

JEN's second submission discussed Origin Energy's and the Minister's submissions on pass throughs. JEN agreed with the Minister's submission on the definition of a regulatory change event—that is, the AER had interpreted a 'regulatory change event' too narrowly. JEN also made comments about the AER's materiality threshold (in response to Origin Energy's submissions).[47] It reiterated it's consideration that the AER does not have power to set materiality thresholds in determinations, and noted Origin's disagreement with CitiPower and Powercor's threshold—namely, that the event has a 'material financial impact on the DNSP' on the basis that it would create room for interpretation.[48] In response, JEN noted that whilst the AER's approach may make it clearer for DNSPs as to whether or not a pass through application should be made, it did not justify the 'inconsistency' with the NEO and RPP that the current threshold represents.[49]

CitiPower and Powercor also provided a further submission, on the Victorian Bushfire Royal Commission (VBRC). CitiPower and Powercor stated that the VBRC supports

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45 JEN, *2011–15 regulatory proposal: Further response to the draft determination,* August 2010, pp. 1–2.

46 ibid.

47 JEN *2011–15 regulatory proposal: Response to stakeholder submissions,* 24 September 2011, attachment four.

48 ibid.

49 ibid.

the inclusion of a nominated pass through for new obligations and requirements arising from the VBRC report.[50]

On the issue of changed obligations introduced by ESV, CitiPower and Powercor stated:

> The VBRC's Final Report also underlines the need for a nominated pass through for the introduction of new or changed obligations or requirements through the approval of schemes or plans required under the Electricity Safety Act 1998 (Vic) or the instruments made or issued there under, including in particular a distributor's electricity safety management scheme. This is because the VBRC:
>
> - contemplated that many of its recommendations would be implemented by the ESV through the exercise of its administrative functions and powers including in particular the approval of these schemes or plans; and
>
> - in so doing, demonstrated the real likelihood that new or changed obligations or requirements unrelated to the VBRC's Final Report would be imposed on distributors in this manner during the regulatory control period.[51]

Powercor and CitiPower stated that the VBRC recommended the creation of a 'trigger event' to ensure the DNSPs could recover costs of implementing the VBRC's recommendations. Powercor and Citipower maintained that there was still significant uncertainty as to whether or not this would fall within the NER defined pass through events (and that the event would likely not be captured under the definition of a regulatory change event).

In its submission, the EUAA stated that the AER should ensure that there is a rigorous assessment of pass through applications from the DNSPs'. The EUAA also stated that, if decisions by the Victorian Government that involve major VBRC related costs are forthcoming before the AER finalises its distribution determination, then this assessment and consultation on the proposals should take place beforehand.[52]

In its submission, Origin Energy agreed with the AER's interpretation of 'service standard event'. It stated:

> A 'service standard event' carries with it the condition that the event in question should substantially affect the manner in which the DNSP is required to provide a direct control service. This is a reasonable threshold for a new government requirement to pass before it should be considered in the context of cost pass through, but broad enough to capture new financial, operational or capital obligations imposed on DNSPs as a result of the Royal Commission.[53]

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50 CitiPower/Powercor, *Victorian Bushfire Royal Commission—implications of final report for the EDPR*, August 2010, p. 2.

51 ibid., pp. 1–2.

52 EUAA, *AER Draft Determination on Victorian electricity distribution prices for the period 2011–2015 and distributors revised proposals*, August 2010, p. 37.

53 Origin Energy, *Victorian Electricity Distribution Draft Determination and Revised Proposals*, August 2010, pp. 5–6.

On the issue of materiality, Origin Energy agreed with the AER's draft determination, stating:

> Origin also supports the AER setting specific percentage limits in the materiality threshold for nominated pass through events. These limits mean that a nominated pass through event can only be approved if it has a material impact on the DNSP, with materiality defined as a given percentage of revenue…. Origin would be concerned if a broad variety of nominated pass through events were approved, and these were subsequently interpreted to capture a much wider range of events and associated costs than intended; particularly if the related materiality thresholds were insufficiently robust. As such, Origin supports the AER's draft determination in this area.[54]

VCOSS stated that the AER must scrutinise any pass through of costs associated with the VBRC.[55] VCOSS also supported the AER's draft decision materiality threshold of one percent.[56] VCOSS further noted that tax change events proposed by DNSPs in their original regulatory proposals were not clear, and should not be treated as nominated pass through events for the distribution determination.[57]

16.6 Issues and AER considerations

The following sections set out the AER's approach to issues raised by the Victorian DNSPs, and stakeholders. The discussion is ordered in the following manner:

- Materiality threshold— this section sets out the AER's considerations on the appropriate materiality threshold, and why it considers that this materiality threshold is consistent with the NEO and RPP
- NER defined events—this sets out the AER's analysis of the NER defined events, particularly the regulatory change event
- Insurer credit risk event—this section sets out the AER's response to the issues raised with its definition of insurer credit risk event
- ESMS event— this sections outlines AER's considerations of this event, and the reasons for its rejection as a nominated pass through event
- Asbestos compensation event— this sections outlines AER's considerations of this event, and the reasons for its rejection as a nominated pass through event
- Transmission costs event— this sections outlines AER's considerations of this event, and the reasons for its rejection as a nominated pass through event
- Premium feed in tariff event — this reiterates the AER's draft decision on this event

[54] ibid.
[55] VCOSS, *Submission to the AER distribution price review, draft determination*, 7 September 2010, pp. 2–3.
[56] ibid., p. 3.
[57] ibid.

- Force majeure event – this sections outlines AER's considerations of this event, and the reasons for its rejection as a nominated pass through event

- Financial failure of a retailer event— this sections outlines AER's considerations of this event, and the reasons for its rejection as a nominated pass through event

- Insurance cap event— this sets out the AER's considerations in amending the definition of the insurance cap event in light of the Victorian DNSPs' revised regulatory proposals

- General nominated pass through event— this sections outlines AER's considerations of this event, and the reasons for its rejection as a nominated pass through event

16.6.1 Materiality threshold

16.6.1.1 AER draft decision

The AER's draft decision was to apply a materiality threshold of one per cent of the smoothed forecast revenue in each regulatory year of the regulatory control period to all nominated pass through events. The AER considered this appropriate for several reasons.[58]

16.6.1.2 Victorian DNSP revised regulatory proposals

All five Victorian DNSPs disputed the one per cent materiality threshold on nominated pass through events in the AER's draft decision (the regulatory proposals' discussions on this are contained at section 16.2.1 above). Issues raised by the DNSPs were:

- the one percent materiality threshold is too high and does not allow DNSPs an reasonable opportunity to recover at least their efficient costs (as is mandated by the revenue and pricing principles (RPP) set out in s. 7A of the NEL)

- the proposed one percent materiality threshold is in conflict with the NEO and RPP in the NEL generally and does not meet the definition of 'materially' in the NER, nor a dictionary definition of 'material'.

- the AER's reasoning is inconsistent, particularly:

  - it is inconsistent with previous distribution determinations, where the AER has applied a materiality threshold of administrative costs to nominated pass through events

  - consistency with the materiality threshold for transmission (which was considered in the AER's draft decision) is an irrelevant consideration, as the NER clearly envisages different materiality thresholds to apply to distribution and transmission networks

[58] AER, *Draft decision*, pp. 713–718.

- there is a relative asymmetry in the incidence of negative pass through events as to positive pass through events, resulting in downside financial exposure for the DNSPs and systematic under recovery of costs (and no other form of compensation has been provided, through the WACC or by a self insurance allowance)

- the AER's materiality threshold leads to a fundamental reassignment of risk from customers to DNSPs, which, again, has not been compensated for

- the AER's interpretation of 'materially' is incorrect, and is not aligned with the definition of 'positive change event' in the NER (and therefore, the materiality threshold does not comply with the NER) [59]

- the one percent threshold would force DNSPs to 'over insure' for risks [60]

- the one percent threshold would result in a lower rate of return than that specified in the draft decision.

- the AER did not have the power to set a materiality threshold as part of the distribution determination.[61]

16.6.1.3 Submissions

Both Origin Energy and VCOSS supported the AER's draft decision materiality threshold.[62] The EUAA stated that the AER should rigorously assess pass through applications received from the DNSPs.[63] EnergyAustralia made similar comments to the Victorian DNSPs in response to the AER's attempt to align its materiality threshold with the definition of 'positive change event' in the NER.[64]It also considered that the materiality threshold should be aligned with the RPP. EnergyAustralia also stated that the NER deliberately distinguishes between the meaning of the word 'materially' for TNSPs and DNSPs. EnergyAustralia also noted that the AER has a broad discretion in relation to cost pass through events.[65] The EUCV commented on the interplay between the risk borne by the DNSPs with the rate of return they are permitted to earn under the distribution determination.[66]

59 CitiPower, *Revised regulatory proposal*, pp. 414–417; Powercor, *Revised regulatory proposal*, pp. 414–417, JEN, *Revised regulatory proposal*, pp. 293–295; SP AusNet, *Revised regulatory proposal*, pp. 354–356; United Energy *Revised regulatory proposal*, pp. 333–335.

60 JEN, *Revised regulatory proposal*, pp. 293–295

61 ibid.

62 VCOSS, *Submission to the AER*, 7 September 2010, pp. 2–3; Origin Energy, *Submission to the AER*,, August 2010, pp. 5–6.

63 EUAA, *Submission to the AER*, 19 August 2010, p. 37.

64 Energy Australia, Submission to the AER, 19 August 2010, pp. 17–18.

65 ibid.

66 EUCV, Submission to the AER, 19 August 2010, p. 56.

16.6.1.4 Issues and AER considerations

The AER considers it pertinent, as part of this final decision, to reiterate its approach on cost pass throughs and the various issues that have been considered as part of developing this approach.[67]

The AER notes that there are several areas where the concept of materiality already exists, in the NER regulatory regime and in various other regulatory regimes.

In the NER, chapter 10 defined 'materially' for transmission networks as an event that:

> results in a Transmission Network Service Provider incurring materially higher or materially lower costs if the change in costs (as opposed to the revenue impact) that the Transmission Network Service Provider has incurred and is likely to incur in any regulatory year of the regulatory control period, as a result of that event, exceeds 1% of the maximum allowed revenue for the Transmission Network Service Provider for that regulatory year[68]

However, for distribution networks, the word is given its ordinary meaning.

In other regulatory environments, a one percent threshold has also been defined as being 'material'. This has been accepted, for example, by the Queensland Competition Authority (QCA), and the Independent Price and Regulatory Tribunal of NSW (IPART).

It has been noted by several stakeholders that the NER confers a broad discretion upon the AER in relation to cost pass throughs. Among other matters, the NER allows the AER to nominate additional pass through events (beyond those already set out in the NER). As part of this discretion, the AER is able to set a materiality threshold for those events. [69]

In its draft decision, the AER outlined, in detail its approach to materiality. In doing so, the AER set out its considerations for fixing a one percent materiality of revenue threshold, including its views on why it considered this threshold to be appropriate. As a preliminary observation, the AER notes that this threshold has been historically accepted by other jurisdictional regulators. It has also been accepted by several DNSPs in the context of the general pass through event in previous determinations.[70] Moreover, it was proposed by several Victorian DNSPs in their initial regulatory proposals (albeit in the context of their proposed general pass through events).

The AER has in its previous distribution determinations for the Queensland and South Australian DNSPs and in its draft distribution determination for Victorian DNSPs, referred to the 'incentive regime' that operates as part of the pass through arrangements. The AER, in clarifying issues relating to this incentive framework in

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67 The AER notes that this has been discussed to some extent in its draft decision. In that document, the AER discussed the interplay between controllability, magnitude, probability and forseeability and how the interplay of those factors determined the appropriate treatment of risks as self insurance and pass through events. See AER, *Draft decision*, pp. 711–713.

68 NER, chapter 10.

69 NER, chapter 10. See definition of pass through event.

70 For further discussion on this, see below.

response to submissions and the DNSPs revised proposals, has drawn upon the work of the AEMC.

The following excerpt from the AEMC explains incentive regulation and while it refers specifically to TSNPs, the AER considers that the concepts underpinning incentive regulation, as expressed by the AEMC, apply equally to DNSPs. The AEMC stated:

> An alternative to cost of service regulation is incentive regulation. While cost of service regulation is based on remunerating TSNPs in respect of their *actual* costs, incentive regulation is based on remunerating TNSPs in respect of their *forecast* costs over the regulatory control period…. Because TNSPs are able to capture a proportion of benefits of any anticipation cost reduction (and must absorb unanticipated cost increases) that occur during a regulatory control period, they are encouraged to make cost savings. At the end of the period, the actual costs in this period may be used as a *basis* for establishing the reasonableness of the cost estimates provided by the TNSP in the subsequent regulatory control period. In this way consumers share the benefits of the efficient gains secured by the TNSP just as in a competitive market cost savings are ultimately passed to customer as lower prices[71].

This excerpt sets out the broad incentive framework to which regulated network service providers are subject generally. However, it is accepted that the costs forecast at the time of the regulatory determination will almost never be exactly equal to actual costs over the regulatory period and that there will be some overspend or underspend of either capex or opex, or both.

This can arise for several reasons. For example, it can occur when forecasts and outturn costs simply do not align due to lower or higher demand. It might also arise where projects, which were forecast at the beginning of the regulatory control period, are not undertaken as planned. The AER considers that a DNSP has adequate incentives to manage these types of risks throughout the regulatory control period and that action from the AER is not, in these circumstances, required.

However, the AER notes that occasionally events which carry substantial cost impacts can occur within the regulatory period. The distribution determination process does not compensate DNSPs for these events as the cost and timing of these events cannot be factored into the opex and capex allowances. It is for these types of events that a pass through mechanism is necessary. The DNSPs should not be financially undermined by large scale events which threaten the reliability and security of the network.

In taking a 'first principles' approach, the AER considered at length the role that pass throughs should play in the regulatory regime. The AER noted that there had not been a consistent approach for DNSPs to date (given that DNSPs have previously been subject to various jurisdictional regulatory regimes). The AER sought to create a regime that would allow DNSPs to recover costs that could not be forecast with any certainty at the time of the determination and were not provided for in other areas of the regulatory regime (for example, through the WACC). This approach is clearly consistent with the NEO and the RPP.

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71 AEMC, Rule Determination , *National Electricity Amendment (Economic Regulation of Transmission Services, Rule 2006 No. 18,* 16 November 2006, p. 93.

In order to achieve these objectives, several factors needed to be considered. The pass through regime cannot be considered as a standalone cost recovery mechanism, rather, it must be considered as part of the broader regulatory regime.

Of significance, the AER considered the appropriate risk sharing that should occur between the customer and the DNSPs, and the extent to which incurred costs from unexpected events need to be recovered by DNSPs. The AER considers that these are interrelated.

On the first issue, the AER notes one of the fundamental functions of the pass through regime is to allow DNSPs to pass back some costs associated with unexpected events to network users. This is to offer some degree of protection in the event that a high magnitude, uncontrollable event occurs, such that the financial viability of the DNSP is not undermined, and that the security and reliability of the network are not threatened. Again, this is consistent with the NEO (see, e.g., s.7 (b) of the NEL). The AER does not consider that providing 100 per cent recovery for all costs incurred by the service provider is consistent with promoting the NEO (see s. 7(a) of the NEL), in promoting the long terms interests of consumers with respect to price. To permit the annual pass through of *all* costs incurred would create a price volatility which is undesirable for customers (where non-recovery of those costs does not present a situation where the security or reliability of the network is undermined).

The AER also considers that such a cost of service regime may impact on the efficiency incentives of the DNSP. While noting that pass through events are excluded from the EBSS, the AER considers that allowing for a 'cost of service' regulatory regime removes the incentive for DNSPs mitigate, where possible, costs from unexpected events. Therefore, full recovery or compensation for events (which would occur under several materiality thresholds proposed by the DNSPs, for example, a zero materiality threshold) would be inconsistent with the RPP, particularly, s.7A (3) of the NEL, which compels the AER to provide incentives for DNSPs to act efficiently.

This leads to the logical conclusion that a cost of service regime, with a zero or otherwise unworkably low materiality threshold, is not desirable. Therefore, it follows, that some materiality threshold should be in place to prevent such a regime from arising. The corollary to this is determining the threshold that should apply. The AER acknowledges that the NER does not, save the Chapter 6A transmission rules, provide any guidance on this issue.

The AER considers that while there is no dollar or percentage amount placed on materiality thresholds in Chapter 6 of the NER, it is appropriate to set (in a distribution determination) such threshold. Apart from regulatory certainty, the AER considers that this is appropriate and desirable for the following reasons.

The AER has considered what has historically been considered by regulators and policy makers as 'material.'

The AER has, in previous distribution determinations, set a one percent materiality threshold on its general nominated pass through event. For example, in setting this in the South Australian distribution determination, the AER noted:

> The AER notes, however, the following matters which support the adoption of a uniform 1 per cent of revenue materiality threshold. The figure has been accepted in different jurisdictions, including IPART and the QCA, and by some DNSPs including Ergon Energy and Country Energy, amongst others. The AER considers that the 1 per cent of annual revenue threshold has operated successfully in those jurisdictions with this (or a similar) threshold. The AER is also unaware of any DNSP not having met its service obligations by reason of the operation of the threshold and the resultant inability to pass costs through to customers. The AER does not agree with SP AusNet that 1 per cent of revenue is too high and would undermine the ability of the DNSP to recover its efficient costs.[72]

This provides some guidance as to the historical consideration of what is 'material', as decided by other Australian regulators.

The AER also notes that there is some guidance in the NEL and NER as to what policy makers have considered is 'material'. Although the AER accepts that the NER treats TNSPs and DNSPs differently in respect of the materiality threshold for NER defined events, a one per cent materiality threshold does exist in the NER in the context of transmission. As this threshold does appear in Chapter 6A of the NER, it is a threshold that is clearly consistent with the NEO and the RPP. The RPP do not differentiate between DNSPs and TNSPs as denoted by the use of the term 'regulated network provider'. As stated above, the AER's broad discretion in determining the additional pass through events that are to apply during a regulatory control period are subject to the NEO and RPP. Accordingly, the AER considers that a one per cent materiality threshold for additional—as opposed to NER defined—pass through events is appropriate and reasonable.

A percentage or dollar threshold is also consistent with the policy intention outlined in the development of chapter 6 of the NER. In its policy document for the development of the distribution rules, the Ministerial Council on Energy—Steering Committee of Officials (SCO) noted there is no justification in terms of differences in the underlying characteristics of electricity distribution networks for the rules to differ from those for electricity transmission networks.[73] That document also noted that the flexibility in the NER would allow the AER to evolve its approach over distribution determinations, with a view to eventual codification. In developing chapter 6, SCO envisaged similar pass through arrangements for DNSPs as were currently in place for TNSPs.[74] In support of the view that transmission and distribution are not fundamentally different, SCO further noted that:

> However, there has not been a consistent approach by jurisdictional regulators to defining pass-through events for distribution. In transmission there has been consistency, which allows for codification. [75]

The AER maintains that these observations from SCO lend further support to a threshold expressed in percentage terms for additional pass through events.

[72] See AER, *Distribution determination for South Australia, final decision*, May 2010, p. 236.

[73] SCO, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution, Explanatory Material,* April 2007 p. 13.

[74] ibid, p. 13.

[75] ibid., p. 53.

The AER notes that, although the Victorian DNSPs did not accept its materiality threshold as per the draft decision, other industry stakeholders such as VCOSS and Origin Energy expressed strong support for the one percent materiality threshold.[76]

The AER has considered the arguments put forward by the DNSPs in respect of the materiality threshold below.

16.6.1.5 Power to set a materiality threshold

JEN submitted that:

- the AER has erred in setting a materiality threshold as part of this distribution determination for nominated pass through events.
- a materiality threshold was not a constituent decision required under cl. 6.12.1 of the NER. JEN also seemed to suggest that the AER had somehow erred by not having published guidelines pursuant to clause 6.2.8 of the NER whereby it could have decided upon a materiality threshold.[77]
- United Energy made a similar submission regarding clause 6.2.8 of the NER.[78]

The AER rejects any contention that is acting outside of its power by mandating a materiality threshold for nominated pass through events in its distribution determination.

As set out above, the AER has a broad discretion in respect of its constituent decision on the additional or nominated pass through events that are to apply in a regulatory control period. As part of that discretion, the AER may, set a materiality threshold for nominated pass through events. EnergyAustralia's submission noted that the AER has broad discretion in its treatment of pass though events.

In addition, such an approach is consistent with the NER defined events all of which contain a materiality threshold. For example, a 'terrorism event' is constituted not only by an act that is said to amount to terrorism; it must also result in a material increase in the costs to a DNSP of providing direct control services. Alternatively, as NER defined pass through events contain a precondition that they materially increase or decrease the costs of providing direct control services, arguably all other events nominated by DNSPs, in order to constitute pass through events, must also contain a materiality threshold.

The AER also noted that it may, in accordance with clause 6.2.8(4) of the NER, publish guidelines as to the AER's likely approach to determining materiality in the context of possible pass through events. However, it is not required to do so. This clause does not limit the AER's ability to prescribe a materiality threshold for nominated pass through events in a distribution determination.

For these reasons, the AER does not agree with JEN's submission nor the submission of United Energy referred to above.

[76] Origin Energy, Submission to the AER, pp, 5–6.
[77] JEN, *revised regulatory proposal*, pp. 293–294.
[78] United Energy, *revised regulatory proposal*, pp. 326–322.

16.6.1.6 Definition of 'material'

The manner in which the word 'materially' is defined was also raised by CitiPower, Powercor, SP AusNet and United Energy. These DNSPs stated that the word 'materially' is to be defined in accordance with its ordinary meaning.

CitiPower and Powercor contended:

- The word materially that this means 'serious, important; of consequence'.[79]
- the proposed one percent materiality threshold does not meet the definition of 'materially' in the NER.[80]
- that setting a materiality threshold of one percent fails to align the threshold with the definition of 'positive change event' in the NER.[81]
- most events which would 'materially' affect them would fail to satisfy the AER's one percent threshold.[82]
- United Energy also submitted that the AER is compelled to apply the ordinary meaning of the word materially.[83] It also stated that:
- neither a guideline nor a determination can change the meaning of 'materially' in the NER.[84]
- to align the materiality threshold with the definition of 'positive change event', the AER needs to consider materiality on a case by case basis.[85]

The AER in its draft decision agreed that the word materially—as it appears in the NER—is to be defined in accordance with its ordinary meaning.[86] The AER did not set out a dictionary definition of the word material in its draft decision. It did, however, consider the nature of the definition—as suggested by CitiPower and Powercor above. However, the AER disagrees that the materiality threshold for nominated pass through events is to be defined in this way. Rather, the AER was explicit in its draft decision that the materiality threshold for the Victorian DNSPs would be 'a percentage of revenue' and that this should be 'one per cent of the smoothed forecast revenue in each of the years of the regulatory control period.'[87] The AER considered that this provided greater objectivity and certainty than a dictionary style definition which would be subjective to subjective and variable assessment.

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79 CitiPower, *Revised regulatory proposal*, pp. 415–416; Powercor, *Revised regulatory proposal*, pp. 414 –415—quoting Shorter Oxford Dictionary.

80 ibid

81 ibid

82 ibid

83 United Energy, *Revised regulatory proposal*, pp. 333–334.

84 ibid

85 ibid.

86 AER, *Draft decision*, p. 714.

87 ibid., pp. 714–718.

16.6.1.7 Consistency with NER materiality threshold

CitiPower and Powercor asserted that setting a materiality threshold of one percent does not align with the threshold in the definition of positive change event in the NER.

The AER notes United Energy's argument—that to align the materiality threshold with the definition of positive change event the AER would need to consider what is material on a case by case basis.

This appears to be misconceived. The AER was not attempting to align the materiality threshold for nominated events with that of a positive change event. The AER was attempting to provide surety that the costs of nominated pass through events could ultimately be passed through. The AER was not suggesting that the one per cent materiality threshold equated to the definition of material in the NER. Furthermore, the AER does not considered that it must do so.

The AER emphasises that the discussion of the ordinary meaning of the word materially in the draft decision was in the context of the AER re-assessing the approach it had adopted in its previous distribution determinations and its related discussion of clause 6.6.1 of the NER.[88] In relation to the former, the AER considered that the threshold previously used in its distribution determinations—the administrative costs of assessing a pass through application—would not generally meet the ordinary meaning of the word materially. The AER was principally concerned that this threshold would prevent DNSPs from (upon the occurrence of a positive or negative change event) recovering costs in accordance with clause 6.6.1 of the NER. This is because a positive change event and negative change event are both defined in terms of pass through events that *materially* increase (or decrease as the case may be) the costs of providing direct control services. Thus, the materiality threshold contained in clause 6.6.1 of the NER would need to be 'serious' or 'significant'. It is generally unlikely that the administrative costs of assessing a pass through application would meet this threshold.

Accordingly, the AER considered that to avert such a situation it should:

> align the materiality threshold contained for additional pass through events that meets the ordinary meaning of the word '*materially*'[89]

For clarity, when the AER indicated that it intended to 'align' the thresholds, it considered that a one per cent materiality threshold for nominated pass through events would ensure that the threshold in clause 6.6.1 would also be met. As a result, the AER would be more likely to be able to pass through costs upon the occurrence of these events. A one per cent materiality threshold for a nominated pass through event would likely in most cases (if not all) satisfy the requirement of a positive change event in clause 6.6.1 of the NER. In other words, a one per cent materiality threshold will generally include costs that are 'material', that is 'serious' or significant'. This approach better achieves the NEO and the RPP by ensuring that DNSPs are ultimately able to pass through costs.

88 ibid., pp. 714–718.
89 AER. *Draft decision*, p. 714.

16.6.1.8 Definition of 'materially' in the NER

CitiPower and Powercor argued that:

- the proposed one percent materiality threshold does not meet the definition of materially in the NER.
- if the materiality threshold for nominated events reflected the ordinary meaning of the word material that this would better achieve the AER's stated objective of a materiality threshold to 'reduce the administrative burden of excessive applications for pass through events, while still including events which may materially affect the business.'

United Energy argued

- the AER is compelled to apply the ordinary meaning of the word materially and that neither a guideline nor a determination can alter the meaning of the word materially in the NER

There is no requirement in the NER that the materiality threshold for nominated pass through events corresponds with the threshold in the NER. Nor is the word materially defined in the NER (in respect of cost pass through for DNSPs). Also, as previously stated, the AER has a broad discretion in deciding the nominated or additional pass through events that are to apply during a regulatory control period. The AER has chosen specifically, having had regard to the NEO and the RPP, to adopt a one percent materiality threshold.

The AER disagrees with this CitiPower and Powercor's second assertion above. If the AER was required to determine on a case by case basis whether a nominated event was material this would require an examination of a range of matters specific to each individual application. This is obviated by a one per cent materiality threshold. In addition, such a threshold promotes regulatory certainty for DNSPs by specifying up front a materiality threshold for nominated pass through events. It follows that the AER also disagrees with the submission that its sole objective in adopting a uniform materiality threshold was to reduce its administrative burden.

Transmission materiality threshold

Citipower, Powercor and United Energy also submitted that:

- the NER distinguishes between the treatment of the transmission and distribution materiality thresholds.[90]
- if the one per cent materiality threshold was intended to apply to distribution as well as transmission, this would be set out in the NER.[91]
- CitiPower and Powercor stated that:

[90] EnergyAustralia made a similar point. See EnergyAustralia, *Submission to the AER*, p. 18.

[91] CitiPower, *Revised regulatory proposal*, p. 416; CitiPower, *Revised regulatory proposal*, p. 416; United Energy, *Revised regulatory proposal*, p. 333–335.

- as the MCE's SCO had not applied a 'reopener' provision to distribution businesses, that this further demonstrated that materiality in a distribution context was intended to be lower than for transmission.[92]

- it was unreasonable for the AER to set a materiality threshold that was consistent with transmission, but not with its previous distribution determinations. [93]

- it was unreasonable for the AER to devise a materiality threshold that ensured consistency with transmission cost pass throughs but which was not consistent with its previous distribution determinations.[94]

- the AER was unjustified in applying a different threshold for nominated pass through events from that applied in its previous distribution determinations and that other jurisdictional regulators had not applied such a threshold.[95]

The AER notes that in devising the materiality threshold for nominated events, the one per cent materiality threshold in transmission was but one factor it took into account.[96] The AER's draft decision did note the materiality threshold for transmission and considered that consistency between transmission and distribution regulation was desirable. (The AER also cited the observation made by MCE's SCO in its development of Chapter 6 of the NER that the provisions for the treatment of cost pass through for the DNSPs should be broadly similar to those for TNSPs).[97] However, the AER also considered that a one per cent materiality threshold was appropriate for the reasons set out above (for example, the threshold having been applied in previous distribution determinations for the 'general nominated' pass through event, it having been accepted in different jurisdictions by a number of DNSPs). The AER also considers that if a lower materiality threshold was intended for distribution that this would be set out in the NEL or the NER and that the AER would not have been given the broad discretion that it has in respect of additional or nominated pass through events. For these reasons, the AER does not accept the arguments put by Citipower, Powercor and United Energy.

For the reasons given in the preceding paragraphs and in the introductory parts of this chapter, the AER disagrees with these submissions.

16.6.1.9 Administrative costs threshold

JEN contended that any materiality threshold should be set to reflect the administrative costs of assessing pass through applications.[98] For the reasons

92 ibid.
93 CitiPower, *Revised regulatory proposal*, p. 416; CitiPower, *Revised regulatory proposal*, pp. 404-408.
94 ibid
95 CitiPower, *Revised regulatory proposal*, pp 412-416; CitiPower, *Revised regulatory proposal*, pp. 404-408; United Energy *Revised regulatory proposal*, p. 326.
96 AER, *Draft decision*, pp. 714–718.
97 Ministerial Council on Energy (MCE) Standing Committee of Officials, *Explanatory material—revenue and pricing principles*, p. 13, also see AER, *Draft decision*, pp. 720–721.
98 JEN, *Revised regulatory proposal*, pp. 293–294.

provided above and in the AER's draft decision the AER considers that such threshold proposed by JEN is not appropriate.[99]

16.6.1.10 Consistency with the NEO and RPP

JEN also submitted that, even if the AER is empowered to set a materiality threshold, the one per cent materiality threshold conflicts with the NEO and the RPP.[100] United Energy and SP AusNet also submitted that this threshold was in conflict with the NEO.[101]

CitiPower and Powercor stated that:

- the AER's approach is inconsistent with the NEO and the RPP in s. 7A(2) of the NEL.[102]

SP AusNet argued that

- the '(the threshold) does not provide SP AusNet with a "reasonable opportunity to recover at least the efficient costs the operator incurs in … providing direct control services".'[103] (This requirement is found in the RPP, specifically s. 7A(2) of the NEL.)
- a one per cent threshold would incentivise DNSPs to over-insure to reduce their financial risk which is contrary to the RPP, particularly the RPP in s. 7A(3) of the NEL (requiring businesses to be provided with incentives to efficiently provide network services).[104]

United Energy stated that:

- a one per cent threshold would preclude it from recovering its costs and that the AER's threshold would deny it the opportunity to earn up to one per cent of the required revenue.[105]

The NEO effectively provides that the objective of the NEL is to 'promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.' This is with respect to such matters as price, in terms of the supply of electricity and such matters as reliability of the national electricity system. The AER considers that a one per cent materiality threshold reflects the efficiency requirements in the NEO. The NEO does not require that a DNSP be able to recover *all* of its costs—in fact, the NEO is concerned with, among other matters, the price of the supply of electricity to consumers. The incentive framework within the NEL and the NER requires DNSPs to appropriately manage

99 ibid, and *AER draft decision*, pp. 714–718.
100 JEN, *Revised regulatory proposal*, pp. 293–294.
101 United Energy, *Revised regulatory proposal,* pp. 326; SP AusNet, *Revised regulatory proposal,* pp. 351–354.
102 CitiPower, *Revised regulatory proposal,* pp. 412–419; CitiPower, *Revised regulatory proposal,* pp. 412–419.
103 SP AusNet, *Revised regulatory proposal,* pp. 351–354.
104 JEN, *Revised regulatory proposal,* pp. 293–294.; SP AusNet, *Revised regulatory proposal,* pp. 351–354.
105 United Energy, *Revised regulatory proposal,* p. 333–335.

risk; consumers should not be required to bear all costs that a DNSP incurs in providing direct control services. The AER made this point in its draft decision. The defined pass through events in the NER recognise this as they each contain a materiality threshold. As a one per cent materiality threshold also exists in the NER in the context of transmission, it is difficult to accept that a one per cent materiality threshold is inconsistent with the NEO. As previously stated, the use of the term 'regulated network service provider' in the NEO indicates that there is no distinction between the application of the NEO to DNSPs and TNSPs. The AER also notes that the DNSPs have offered no substantive reason why the AER's materiality threshold is inconsistent with the NEO. The AER also notes that the DNSPs have offered no substantive reason why the AER's materiality threshold is inconsistent with the NEO.

In addition, as noted above in the AER's discussion of the NEO, the RPP apply in the same manner to TSNPs and DNSPs. If the NER specifically provides that TNSPs have an opportunity to recover at least their efficient costs notwithstanding the one per cent materiality threshold that applies to them, it is clear that a one per cent materiality threshold does satisfy the RPP.

For the reasons in the preceding paragraphs, it is not possible to maintain that the AER's materiality threshold conflicts with the RPP in s. 7A(3) of the NEL (that is, that a DNSP should be provided with efficient incentives to promote economic efficiency with respect to the provision of the services it provides).

16.6.1.11 Incentives to 'over insure'

The AER also disagrees with the submissions that a one percent materiality threshold would force DNSPs to 'over insure' for the risk they would be exposed to (that is, the risk that they are facing for costs under the one percent materiality threshold). Any amounts in excess of an insurance cap are likely to be greater than the AER's proposed materiality threshold for nominated pass through events. Nor have the DNSPs provided any information to the AER in their revised regulatory proposals that would indicate that their insurance caps on external insurance policies would be below the AER's proposed materiality threshold.

The AER's draft decision on self insurance assessment also allowed self insurance for below deductible amounts on insurance policies.[106] Accordingly, where a DNSP seeks to insure for an event that is also eligible for a pass through event, the DNSP has an opportunity to recover its efficient costs through:

- a self insurance allowance (provided throughout the regulatory control period) for below deductible amounts on external insurance policies
- the inclusion in the building block revenue requirements for insurance amounts paid to the DNSP, which cover the amount above the deductible, up to the insurance cap amount (if any)

[106] The AER recognises that some self insurance allowances proposed by the Victorian DNSPs were rejected, even where they related to below deductible amounts on insurance policies. Though the AER takes an in principal approval of deductible amounts, where those costs are already captured in the base year, or where those costs are capitalised and hence recovered through the regulatory asset base (RAB). See appendix M of the AER's draft decision.

- in the event that the insurance payout is capped, a pass through event which compensates the Victorian DNSPs for any costs incurred above the cap.

16.6.1.12 Interaction with rate of return

CitiPower and Powercor argued that

- the AER's materiality threshold leads to perverse outcomes and represents a re-assignment of risk from customers to DNSPs.
- they should be compensated through their regulated revenues and that the AER had not provided compensation either through the WACC or by providing self-insurance.[107]
- regulation becomes more onerous over time.[108]

SP AusNet and United Energy stated that:

- there are likely to be more positive change events than negative change events.[109]

United Energy stated that

- the one percent materiality threshold results in a lower rate of return (than that in the AER's draft determination).
- there are likely to be more positive events than negative events.[110]

The AER disagrees with the arguments above.

On this issue of expected rates of return, the AER notes that a DNSPs actual return depends on several factors. One of those factors is how effectively, and efficiently the DNSP manages its business within the incentive based regulatory framework. This could render the actual rate of return *higher* than the one set out in the AER's distribution determination. The regulatory regime is incentive based, where the regulatory WACC is set on an ex ante basis. The EUCV noted the interaction of pass through events with the rate of return earned by regulated DNSPs. The EUCV stated in its submission that the Victorian DNSPs enjoy a rate of return that is comparable to other (non regulated) businesses, despite the fact that they face less risk. Further, as the NER includes a materiality threshold for both negative and positive change events, a DNSP will not be able to recover or refund 100 per cent of the costs of these events. In other words, DNSPs will necessarily receive a lower or higher realised return relative to the expected return.

Further, the AER considers that the information asymmetry that exists between the regulator and the Victorian DNSPs is likely to provide the DNSPs with some degree

[107] CitiPower, *Revised regulatory proposal*, pp. 412–419; Powercor, *Revised regulatory proposal*, pp. 412–419; United Energy, *Revised regulatory proposal*, pp. 333–335.

[108] CitiPower, *Revised regulatory proposal*, p. 417; CitiPower, *Revised regulatory proposal*, p. 417.

[109] SP AusNet, *Revised regulatory proposal*, pp. 351–354;

[110] United Energy, *Revised regulatory proposal* pp. 333–335.

of asymmetric upside risk. That is, it is difficult for the AER to accurately quantify all upside costs incurred by DNSPs. Accordingly, the AER contends that in assessing whether the DNSPs are exposed to any asymmetric downside risk in aggregate such that the DNSPs' expected rate of return and the regulatory WACC are not aligned, requires an assessment of the overall regulatory regime, rather than focusing on one element of the regulatory regime, in this case cost pass through.

It is unclear from these DNSPs' submissions what perverse outcomes arise from the AER's materiality threshold. Even if there was some evidence to support this assertion, the AER notes that the materiality threshold addresses the risk inherent in its previous approach of requiring nominated events to have a materiality threshold of the costs of assessing a pass through application. As stated above, and in the AER's draft decision, it is doubtful in many instances that a pass through event with such a low materiality threshold would meet the ordinary meaning of the word material in respect of clause 6.6.1 of the NER. The proposed materiality threshold is likely to overcome these potentially perverse outcomes.

Nor does the AER consider that there has been a re-assignment of risk for the reasons mentioned above, particularly the discussion of upside and downside risks and positive and negative change events. In these circumstances, compensation is not warranted.

The AER also notes that the potential downside incurred by a one percent materiality threshold is, in part, offset by the upside risk. The DNSPs noted that they will have to 'wear' costs of up to one percent of revenue where a pass through event occurs in a regulatory year. However, the AER notes that (in the event of a negative change event) the DNSPs will be required to retain cost decreases up to the one percent threshold (rather than pass them back to customers).

16.6.1.13 Estimated potential losses

CitiPower, Powercor, SP AusNet and United Energy provided estimates of potential losses under the AER's proposed one per cent materiality threshold.[111]

The AER noted above that there may also be countervailing reductions in costs. The Victorian DNSPs have not substantiated their views that there are likely to be more downside pass through events (resulting in cost increases). In addition, the DNSPs have not provided any evidence that would substantiate their estimates of potential losses. The AER also notes that the DNSPs' insurance allowances (included in their forecast operating costs) would recover a significant proportion of costs. Therefore, the AER considers that it is not likely that the DNSPs would incur a significant number of events where they are not insured or where the costs are above the insurance cap but below the AER's materiality threshold.

The AER also notes United Energy's hypothetical example referred to above.[112] In this example, United Energy considered two events each equivalent to 0.9 per cent, neither of which could be passed through. In particular, the AER notes United Energy's assertion that: 'if the draft determination was implemented and one event per year eventuated just below the 1 per cent threshold, it would be possible for UED to

[111] Assuming that one pass through event occurs each year.
[112] United Energy, *Revised regulatory proposal,* p. 334.

lose up to $14 million of revenue…'. United Energy went on to state that 'Such an amount cannot be considered by a reasonable person to be an immaterial amount.'

The AER considers that this submission fails to appreciate the manner in which cost pass throughs operate under the NER. Even if the AER adopted a materiality threshold of less than one per cent, clause 6.6.1 of the NER would not necessarily permit the $14 million of revenue to be passed through to distribution network users. Each event said to be a pass through event would need to be assessed by the AER on its merits. For example, clause 6.6.1 of the NER is prefaced in terms of a positive or negative change event occurring. Such an event may not, for whatever reason, have occurred. Secondly, materially is defined in respect of each pass through event, not cumulative events as United Energy seems to have suggested (see, for example, United Energy's assertion that in each year, several events could potentially occur which may fall just short of the one percent threshold, which could result in losses up to $14 million). Thirdly, if a different materiality threshold was adopted, for example, the $500,000 proposed by Powercor, it may be that amounts falling just shy of this amount could also not be the subject of a cost pass through. The complaint made by United Energy would arise regardless of the materiality threshold adopted. For the reasons given above, the AER is committed to a pre-determined monetary materiality threshold to avoid the problems associated with the previous threshold applied to nominated events. Finally, the AER notes that United Energy's hypothesis related to a loss of revenue, not incurred costs (which is what the pass through regime aims to provide compensation for).

Citipower and Powercor also disagreed with the AER's assertion in its draft decision that a one per cent materiality threshold was comparable to their, then, proposed materiality threshold of $5 million. Notwithstanding this, the AER considers that a one per cent materiality threshold is preferable to different thresholds for different DNSPs.[113]

16.6.1.14 Timing of pass through events

CitiPower and Powercor expressed concerns about the timing of pass through events, stating::

- that costs may not meet the threshold simply because, for example, the said pass through event occurred over June/July rather than December/January.

The AER considers this assumption to be erroneous. Although the materiality threshold is calculated relative to the regulatory year's revenue, there will not be any under recovery of costs based on when they are incurred in that year. For example, costs that are incurred over December/January (for a cost pass through event that commences in December but does not end until January of the following year), the AER will use the revenue requirement of the year when the event commences in calculating whether or not the materiality threshold as been met.

In response to the EUAA, the AER notes that the assessment process for cost pass through events (and the AER's obligations in assessing costs) are set out at cl. 6.6.1 of the NER.

[113] CitiPower, *Revised regulatory proposal*, p. 406; Powercor, *Revised regulatory proposal*, p. 407.

16.6.1.15 AER conclusion

The AER will maintain its draft decision, that is, to apply a materiality threshold of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

16.6.2 NER prescribed pass through events

16.6.2.1 AER draft decision

In its draft decision, the AER rejected several proposed nominated pass through events on the grounds that they appeared to fall within the NER defined pass through events. Specifically, the AER rejected the following events on the grounds that they would likely fall within the definition of 'service standard event' or 'regulatory change event':

- a transfer of non-pricing distribution regulatory arrangements to a national regulatory framework event (proposed by CitiPower and Powercor)
- a change in safety regulations introduced by the ESV event (proposed by CitiPower and Powercor)
- a changes in exposure limits event (proposed by CitiPower and Powercor)
- a recommendations arising from the Royal Commission into Victorian Bushfires event (proposed by Powercor)
- an ETS event (proposed by CitiPower, Powercor, JEN and United Energy) and a CPRS event (proposed by SP AusNet)
- a transfer of customer regulation to the national regulatory framework event (proposed by United Energy)
- an introduction of new regulatory obligations for vegetation management around powerlines event (proposed by United Energy)
- a changes to bushfire mitigation framework event (proposed by United Energy)
- a national broadband network event (proposed by United Energy)
- a change in corporate income tax event (proposed by United Energy)
- an AEMO fees and charges event (proposed by CitiPower and Powercor)

Part of the AER's rationale for this approach is that it would be an inappropriate exercise of its discretion to nominate additional events in a distribution determination if they are already contemplated in the NER. In particular, the AER considered that it should not exercise its discretion in such a way that would enable costs to be passed through to network users where the rules already provide the parameters of the NER defined events. For example, United Energy's proposed 'change in corporate income tax event' should not, in the AER's opinion, constitute an additional pass through event allowing for the recovery of costs arising from changes in corporate income tax when the tax change event in the NER does not extend to the pass through of these costs. The AER also considered that as the NER provides the AER with the discretion to nominate pass through events *in addition* to the events defined in chapter 10 of the NER, this supports its view that that only events beyond those already stipulated in the NER should be nominated in the distribution determination.[114]

In its draft decision, the AER resisted making an assessment of whether the events would satisfy any of the NER defined events. The AER reasoned that such assessments could not be made until the event had occurred and the associated costs could be quantified. For example, in order for any of the NER defined events to be triggered, the event in question would need to substantially affect the manner in which direct control services are provided. This cannot be known until such time as the event occurs.

16.6.2.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs considered that the AER should confirm that these events (or some of these events) would be treated as NER prescribed pass through events. The Victorian DNSPs also suggested that in the absence of confirmation by the AER that these events would be treated as NER prescribed events, the AER should permit these events as nominated pass through events for the purposes of this determination.[115]

JEN, in its revised regulatory proposal, stated:

- the AER's narrow definition of a 'regulatory change event' being confined to changes in existing regulatory obligations creates increased uncertainty as to whether a 'bushfire event' will in fact be an event relating to possible new, changed or removed regulatory obligations that are either already within the scope of the 'regulatory change event'.

- it is appropriate for the DNSPs to be able to recover the costs resulting from the recommendations of the VBRC (and that DNSPs should not be required to bear the burden of the costs of those events).

- A pass through for recommendations arising from the VBRC is consistent with the requirements of the NEL and Rules and should be accepted by the AER.

- the AER should confirm in its final decision that Powercor's proposed 'bushfire event' falls within the 'regulatory change event' or 'service standard event' scope. If the AER is unable to do so, the AER should treat the 'bushfire event' as a nominated pass through event.[116]

114 AER, *Draft decision*, pp. 709–710.
115 JEN, *Revised regulatory proposal*, pp. 295; CitiPower, *Revised regulatory proposal*, pp. 408–409; Powercor, *Revised regulatory proposal*, pp. 408–409; United Energy, *Revised regulatory proposal*, p. 328.
116 JEN, *Revised regulatory proposal*, p. 303.

CitiPower and Powercor stated that:

- by confining a 'regulatory change event' to a change in an existing regulatory obligation, the AER has taken a very literal approach to the interpretation of 'regulatory change event'.

- this approach is contrary to the NEL which provides that in interpreting a provision of the NER, the interpretation that will best achieve the purpose or object of the NER is to be preferred to any other interpretation, including in particular a literal interpretation such as that adopted by the AER

- the definition of 'regulatory change event' should be interpreted in the context of the purpose of distribution pass through events.[117]

CitiPower and Powercor both further stated that the regulatory change event should be interpreted to include the removal of an existing obligation, a change in existing obligations and the imposition of a new obligation.[118] Both DNSPs sought confirmation that the regulatory change event would include new regulatory obligations that arise during the regulatory control period.[119]

SP AusNet submitted that:

- the AER should nominate a VBRC event, as reliance on the service standard event and regulatory change event in the NER created significant uncertainty for the Victorian DNSPs (given that they would be likely be affected by recommendations arising from the VBRC).[120]

United Energy stated that:

- there is no certainty that new regulatory obligations arising during the regulatory control period will meet the criteria for a service standard event.

- there is a flaw in the way in which the AER has interpreted the meaning of 'service standard' event under the NER —a service standard event carries with it the condition that the event should substantially affect the manner in which the DNSP is required to provide a direct control service.

- the AER has suggested a transfer of customer regulations to a national regulatory framework would constitute a service standard event, when in fact, the only change would be to the commercial and legal environment in which United Energy operates in the course of providing distribution services. Such an event would not go to the manner in which United Energy is required to provide a direct control service.

117 CitiPower, *Revised regulatory proposal*, p. 406; Powercor, *Revised regulatory proposal*, p. 406.
118 ibid.
119 ibid.
120 SP AusNet, *Revised regulatory proposal*, p. 352.

- The AER has increased uncertainty about what type of events might fall within the scope of either the 'regulatory change event' or 'service standard event' specified in Chapter 10 of the NER. [121]

16.6.2.3 Submissions

CitiPower/Powercor, JEN and the Minister each made a submission on this issue. Each submission stated that the AER had erred in its interpretation of the breadth or lack thereof of the 'service standard event' and 'regulatory change event'. Much of the concern in this area arises from recommendations flowing from the VBRC.

In connection with this issue, JEN CitiPower and Powercor contended that the AER should confirm in its final decision how it would treat an event arising from the VBRC. JEN explained that this was because it is likely that it would be subject to further legal obligations arising from VBRC recommendations. CitiPower and Powercor's submission discussed the 'trigger event, ' which they stated was recommended by the VBRC. Powercor, in particular, noted the uncertainty of whether new obligations (or recommendations) imposed on DNSPs would fall within the NER defined events. Due to the said uncertainty of the breadth of the service standard and the reach of the regulatory change events, CitiPower and Powercor provided an updated definition of an ESMS event and amended their revised regulatory proposals from 'recommendations arising from the VBRC event' to a 'VBRC response event'. CitiPower and Powercor expressed concern that the service standard event related only to the imposition, or removal, of new obligations that are service standards (in this respect, Powercor cited the definition of 'service standard event' under the NER, and 'regulatory obligation or requirement' under s. 2D of the NEL).

The AER has also received a submission from the Minister for Energy and Resources.[122] The Minister questioned the efficacy of comparing, as the AER did in its draft decision, the definitions of regulatory change event and tax change event as follows:

> The definition of "tax change event" does not pick up the definition of "regulatory obligation or requirement" and it is for that reason, as well as the necessity to make the definition work with clause 6.6.1(j)(6) of the NER (which refers to countervailing taxes being imposed or removed), that the definition refers not only to change but also to imposition and removal of taxes.[123]

16.6.2.4 AER issues and considerations

As noted in its draft decision the AER considers that several proposed nominated pass through events are likely to fall within the definition of one of the NER prescribed pass through events.[124]

As explained earlier in this chapter, the AER considered in its draft decision that it was inappropriate to confirm whether such events would meet the definition of at least one of the NER defined events. However, in the light of the responses to the

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121 United Energy, *Revised regulatory proposal*, pp. 328–329.
122 Minister for Energy and Resources, Submission to the AER, 20 August 2010, p. 11.
123 Minister for Energy and Resources, Submission to the AER, 20 August 2010, p. 11.
124 AER, Draft decision, pp. 709–711.

draft decision, the AER has reconsidered this issue and these considerations are set out in turn below.

CitiPower, Powercor and JEN all stated that for the VBRC event in particular, the final determination should confirm that this will be considered a regulatory change event.[125] These DNSPs also stated that several of the other events that the AER rejected (see above) should be confirmed as NER prescribed pass through events.[126] SP AusNet and United Energy, however, considered that the VBRC event should still be treated as a nominated pass through event.[127]

In its submission, CitiPower and Powercor raised issues with whether or not the service standard event would encapsulate new regulatory obligations (as put forward in the AER's draft decision).[128] CitiPower and Powercor stated:

- in the AER's draft decision, the AER concluded that 'regulatory change event' 'is restricted to changes in existing regulatory obligations and does not encompass the removal or imposition of a new regulatory obligation or requirement…if the AER maintains this view this will likely have the consequence that one or more of the legal obligations or requirements introduced in response to the VBRC's distribution related recommendations do not fall within the definition of 'regulatory change event.'[129]

Powercor also stated:

> Powercor Australia is concerned that the term 'service standard event' may be construed as restricted to the removal of or imposition of new or changed regulatory obligations or requirements that are service standards. This is because:
>
> - regard may properly be had to the dictionary meaning of the phrase 'service standard' in the defined term in construing the definition of that term; and
> - in construing the term 'service standard event' and its definition, the definition must be read as a whole and in its context, which may, in turn, necessitate a consideration of:
> - the second limb of that definition, which refers to imposing, removing or varying 'minimum service standards'; and
> - the NEL definition of the term 'distribution service standard', which term is used in defining the term 'regulatory obligation or requirement' in s2D of the NEL, forms part of the context in which the definition 'service standard event' is read and construed. The term 'distribution service standard' is defined in s2 of the NEL to mean 'a standard relating to the standard of services provided by a regulated distribution

125 CitiPower, *Revised regulatory proposal,* pp. 407–408; Powercor, *Revised regulatory proposal,* pp. 407–408; JEN, *Revised regulatory proposal,* p. 295, pp. 302–303.
126 ibid.
127 SP AusNet, *Revised regulatory proposal,* p. 352–353; United Energy, *Revised regulatory proposal,* pp. 328–329.
128 AER, *Draft decision,* pp. 709–711. CitiPower/Powercor, *Victorian Bushfire Royal Commission—implications of final report for the EDPR,* August 2010, pp. 9–11.
129 ibid., pp. 9–10.

> system operator by means of, or in connection with, a distribution system…'.[130]

The regulatory change event in the NER provides that a regulatory change event is (among other matters), an event that falls within no other category of pass through event.[131] This means, that, in assessing whether or not a regulatory change event has occurred under the NER, the AER would, as a necessary precondition, have already considered whether or not a service standard event, tax change event or terrorism event has occurred. Logically, for the purposes of the VBRC outcomes, it follows that if an event does not qualify as a service standard event (as contended by Powercor above), then the AER would need to assess whether a regulatory change event has occurred.

The AER accepts the view that its initial interpretation of regulatory change event is likely to be too narrow.[132] The AER also acknowledges that, from a policy perspective, it is desirable to permit the pass through of costs of new regulatory obligations, and such costs can be broadly interpreted to include new regulatory obligations that arise during the regulatory control period, including those arising from the VBRC. The AER notes that these changes are likely to come into effect during the forthcoming regulatory control period. However, the AER still considers that several new obligations that arise could still be considered as service standard events. Putting aside the title of the event, they could encompass new obligations that do not necessarily relate to a service standard imposed upon the DNSP. This view has been put forward by EnergyAustralia in its pass through application to the AER for the solar bonus scheme (SBS) event.[133] In its submission, EnergyAustralia stated:

> The SBS is a Service Standard Event which imposes additional costs on EnergyAustralia in providing direct control services. The SBS requires EnergyAustralia to provide connection services to complying generators and to record a credit against charges payable as well as to report six monthly to the relevant Minister. These new obligations have altered the nature of the direct control services EnergyAustralia is required to provide and accelerated the rate at which generators are seeking connection under the SBS. EnergyAustralia incurs additional costs in implementing these obligations. EnergyAustralia has incurred and is likely to incur these costs during the regulatory control period 2009–14 which were unforseen at the time its distribution determination for the regulatory control period was considered and determined by the AER.[134]

EnergyAustralia also provided the following rationale for the SBS as a service standard event, stating:

> The SBS is a service standard event as it represents a legislative or administrative act or decision that has the effect of either altering the nature or scope of direct control services EnergyAustralia provides, or substantially varying the manner in which it provides these services. The SBS has also

[130] ibid

[131] See definition of regulatory change event, subclause (a), NER, chapter 10.

[132] The AER acknowledges clause 7 of Schedule 2 to the NEL which states that 'the interpretation that will best achieve the purpose or object of this Law is to be preferred to any other interpretation'.

[133] This application was made to the AER on 2 September 2010. See www.aer.gov.au

[134] Note the 'SBS' is reference to the solar bonus scheme. EnergyAustralia, *Cost pass through application NSW Solar bonus scheme*, 2 September 2010, p. 1.

> materially increased EnergyAustralia's costs of providing direct control services.[135]

The AER has considered Powercor's concerns, namely, that the VBRC Final Report contemplates that most of its recommendations will be implemented by the ESV by means of the exercise of its functions or powers and that this is not commensurate with the definition of 'regulatory change event' which is restricted to 'regulatory obligations or requirements under an Act or instrument made or issued under such an Act' and does not encompass 'legal obligations or requirements imposed by an administrative act or decision, such as the acts or decisions of ESV'.[136]

The AER has examined the definition of regulatory obligation or requirement under the NEL.[137] The AER acknowledges Powercor's concerns. However, the AER observes that while the recommendations from the VBRC have been made and the Victorian government had indicated that several of the recommendations might be implemented, it is unclear how these recommendations will be given force.

The AER considers that references to 'instrument' in paragraph 2D(1)(b) of the NEL are reasonably broad. This could, for example mean obligations imposed by the ESV, via the ESMS. The AER notes, in particular, that the word 'instrument' is not confined to subordinate legislation as is denoted by the words 'instrument made or issued under or for the *purposes of that Act* (emphasis added)'.

The AER also notes that Powercor has omitted to mention the definition of 'regulatory obligation or requirement' in paragraph 2D(1)(a) of the NEL. It is possible that any obligations imposed on DNSPs arising from the recommendations of the VBRC will fall within one of the relevant subparagraphs, that is, where the regulatory obligation or requirement is-

i. a distribution system safety duty; or

ii. distribution reliability standard; or

iii. a distribution service standard.

Notably, paragraph 2D(1)(a) is not dependent on the existence of legislation or an instrument of any kind.

Turning to the issue of whether or not a regulatory change event has occurred, the AER has further considered the definition of both regulatory change event, and service standard event in the NER. The AER cannot predict whether an obligation or requirement arising from a VBRC recommendation will meet the definition of service standard event. (The AER notes that this would also be the case if the AER nominated an additional event for VBRC recommendations or similar event). However, it would appear, at the very least, from the AER's examination of the VBRC's recommendations that many, if not all of them or, collectively, if they are cast that way by the legislature or the ESV would constitute at least a regulatory change event or events (subject to the materiality threshold being met). The main element that the DNSP would need to demonstrate, apart from the inbuilt materiality

135 ibid., p. 16.
136 ibid., pp. 9–10.
137 NEL, s. 2D.

threshold, is that the change in regulatory obligation or requirement substantially affects the manner in which it provides direct control services.[138] The AER considers that, based on the VBRC's recommendations, this element would be met. However, a definitive assessment on this issue can only be made once the recommendations are enacted.

Given the breadth of the regulatory change event and the AER's views expressed in the preceding paragraph, the AER, while it acknowledges Powercor's concerns about the service standard event, considers that the regulatory change event overcomes these concerns.

The AER will therefore accept a 'regulatory change event' that encompasses any change in regulatory obligation during the regulatory control period, including the removal of an existing regulatory obligation, a change in an existing regulatory obligation and the imposition of new regulatory obligation.

The AER also emphasises that the occurrence of a regulatory change event is subject to the caveat that it 'materially increase or decrease the cost of delivering direct control services'. The very nature of this requirement means that the AER cannot predict in advance whether a regulatory change event (or any pass through event for that matter) has occurred. The AER notes, for completeness, that this requirement must also be met (for a second time) to qualify as a positive change event in clause 6.6.1 of the NER, that is, when the AER assesses whether to pass costs through to network users.

On this latter issue, there are stakeholder concerns about appropriate consultation for costs passed through in association with the VBRC.[139] Under the NER, the AER is able to engage in any consultation as it sees fit when considering the costs to be passed through to consumers.[140] The AER intends to undertake stakeholder consultation in relation to any costs passed through from the VBRC recommendations.

The other events proposed (for which the DNSPs sought clarification) were:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework/a transfer of customer regulation to national regulatory framework event
- changes to safety regulations introduced by the ESV/changes to bushfire mitigation framework
- changes to exposure limits

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[138] The AER notes that a similar element exists for the service standard event. That is, both events contain the qualifier that the event must substantially vary during the course of the regulatory control period the manner in which a DNSP is required to provide a direct control service. It is thus also possible that an obligation or requirement arising out of the VBRC recommendations could also constitute a service standard event.

[139] EUAA, *AER Draft Determination on Victorian electricity distribution prices for the period 2011–2015 and distributors revised proposals* p. 37; VCOSS, *Submission to the AER distribution price review, draft determination*, pp. 2–3.

[140] NER, cl. 6.6.1 (i).

- a national broadband event
- an introduction of new regulatory obligations for vegetation management around powerlines event
- an emissions trading scheme event/ a CPRS event
- an AEMO fees and charges event.[141]

The first four events, as they are currently defined by the DNSPs, would likely fall within the NER prescribed events, *where they substantially affect the manner in which direct control services are provided*, and they *materially increase or decrease costs of providing those services*. As to whether they would be regulatory change events or service standard events, the AER notes (as set out above) that any assessment of regulatory change event is necessarily presaged by an assessment of whether a service standard event has occurred. For this reason, the AER cannot confirm which NER defined event will apply. The AER is conscious that the definitions as they stand would be either service standard events or regulatory change events subject to the other requirements, including the materiality threshold in each definition, also being met. In respect of the AEMO fees and charges event, the AER considers that the definition, as it stands, would meet the tax change event definition in the NER, subject to the qualifying materiality threshold. This is because the 'tax change event' definition contained in the NER refers to a change in a 'relevant tax'.[142] A 'tax' is further defined as:

> Any tax, levy, impost, deduction, charge, rate, rebate, duty, fee or withholding which is levied or imposed by an *Authority.* [143]

An 'Authority' is further defined as:

> Any government, government department, instrumentality, *Minister*, agency, statutory authority or other body in which a government has a controlling interest, and includes the *AEMC, AEMO,* the *AER* and the *ACCC* and their successors. [144]

16.6.2.5 AER conclusion

For the reasons set out above, the AER does not consider it is appropriate or necessary to include the events above as nominated pass through events for the purposes of this distribution determination. In relation to the VBRC, the AER considers that changes arising from the VBRC will be regulatory change events.[145]

16.6.3 Definition of 'insurer credit risk' event

16.6.3.1 AER draft decision

The AER accepted the 'insurer credit risk' event as a nominated pass through.

141 ibid., pp. 708–710.
142 NER, chapter 10.
143 NER, chapter 10.
144 NER, chapter 10.
145 Where they substantially affect the manner in which the DNSP is required to provide direct control services.

16.6.3.2 Victorian DNSP revised regulatory proposals

SP AusNet proposed several modifications to the definition of this pass through event, including updating it to cover DNSPs in the event that insolvency of one of its insurers results in that insurer not being able to pay out under an insurance policy.[146]

16.6.3.3 AER issues and considerations

The AER considers that there is merit in SP AusNet's proposed amendments and considers that they add clarity to the definition of 'insurer credit risk' event.

16.6.3.4 AER conclusion

The AER accepts SP AusNet's proposed amendments and has incorporated them in the definition of insurer credit risk event (see 'AER conclusion' below).

16.6.4 Electricity Safety Management Scheme (ESMS) pass through event

16.6.4.1 AER draft decision

The AER rejected this as a step change (proposed by CitiPower and Powercor) in its draft decision.[147] This was not considered as a pass through in the draft decision.

16.6.4.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor both proposed this be treated as a nominated pass through event on the basis that that it falls within the AER's nominated pass through assessment criteria.[148] United Energy also proposed this as a nominated pass through event.[149]

16.6.4.3 Submissions

CitiPower and Powercor revised the definitions of their ESMS event in a submission to the AER.

The AER notes that, as part of a submission to the AER, both CitiPower and Powercor updated the definition of an ESMS pass through. This revised definition was:

> A management scheme or plan event means the imposition during the regulatory control period of any new or changed obligation or requirement in a management scheme or plan required under the Electricity Safety Act, or an instrument made or issued under that Act, as amended from time to time which imposition is necessary to obtain ESV acceptance or approval of that scheme or plan, including without limitation:
>
> (a) the imposition by ESV of conditions or limitations under s103 of the Electricity Safety Act in respect of the design, construction, operation, maintenance or decommissioning of the supply network on its provisional acceptance of an electricity safety management scheme under section 103 of the Electricity Safety Act;

146 SP AusNet, *Revised regulatory proposal*, pp. 351–352.
147 AER, *Draft decision*, appendix L, pp. 159–160.
148 CitiPower, *Revised regulatory proposal*, p. 413; Powercor, *Revised regulatory proposal*, p. 413.
149 United Energy, *Revised regulatory proposal*, p. 332.

(b) the modification of a proposed electricity safety management scheme in accordance with section 104 of the Electricity Safety Act to include an obligation or requirement necessary to address a reason or reasons for the non-acceptance by the ESV of the scheme;

(c) the imposition by ESV of an obligation or requirement on the ESV's determination of an electricity safety management scheme under section 105 of the Electricity Safety Act;

(d) the revision of an electricity safety management scheme under section 109 to include an obligation or requirement necessary to address one or more of the matters ESV required the revision to address under section 109(2)(b) of the Electricity Safety Act;

(e) the amendment of a proposed management plan relating to compliance with the Electricity Safety (Electric Line Clearance) Regulations 2010 (Vic) to include an obligation or requirement necessary to address one or more of the reasons that ESV required the preparation of an amended plan in accordance with r9(7) of those Regulations; and

(f) the imposition of an obligation or requirement in a bushfire mitigation plan which imposition is necessary to obtain ESV approval of that plan in accordance with section 83A of the Electricity Safety Act. [150]

16.6.4.4 AER issues and considerations

The AER has considered the definition of the ESMS event. It notes the event relates to the imposition, by Energy Safe Victoria (ESV) of:

> conditions or limitations in respect of the design, construction, operation, maintenance or decommissioning of the supply network on its provisional acceptance of an electricity safety management scheme under section 103 of the Electricity Safety Act.[151]

The AER notes that this event relates to changed or new legal or regulatory obligations imposed on CitiPower and Powercor and United Energy. On this basis, the AER considers that this event would fall within the NER 'regulatory change event' (and, possibly, a 'service standard event') subject to it materially increasing or decreasing the costs of providing direct control services. On this basis, the AER does not consider it necessary to include this as a nominated pass through event in this final decision.

16.6.4.5 AER conclusion

The AER maintains its draft decision position to reject the ESMS pass through event proposed by CitiPower, Powercor and United Energy on the basis that it will fall within the NER prescribed pass through events, subject to the materiality threshold in the NER, and the change 'substantially affecting' the manner in which direct control services are provided.

150 ibid., pp. 13–14.
151 ibid.

16.6.5 AER's rejection of asbestos compensation event

16.6.5.1 AER draft decision

The AER rejected this nominated pass through event, proposed by JEN, in its draft decision.

16.6.5.2 Victorian DNSP revised regulatory proposals

JEN submitted that the AER should accept this pass through event.[152] In arguing this, JEN stated that:

- the AER's position was in conflict with the position taken in the NSW distribution determination, where asbestos compensation claims were accepted
- DNSPs should be treated equally, and the AER should not make a distinction between publically and privately owned businesses
- the AER has misdirected itself—the question is not whether a particular risk is one faced by businesses generally, but whether permitting pass through of costs associated with a particular event is consistent with the NEO and RPP.[153]

16.6.5.3 AER issues and considerations

The AER emphasises that any apparent distinction in its treatment of asbestos compensation risks between privately owned and publicly owned DNSPs is unintentional. The AER also acknowledges that this is a risk faced by JEN.

The AER has developed revised assessment criteria for Victoria which achieve greater consistency with the NEO, RPP (see section 16.1) and the incentive framework. The criteria consider which party is best placed to manage the risk in question. The AER considers that the owner of the DNSP (and, it follows, the DNSP's shareholders) are better placed to carry risks associated with asbestos compensation events. This is because the DNSP is able to identify the extent of the risk and take steps to mitigate the risk. The AER notes that, in its NSW distribution determination, it did not accept asbestos risks explicitly. Rather the AER noted that these could potentially fall within the general pass through event.

As discussed in the draft decision the AER considers that it is the responsibility of the purchaser of a business to undertake any due diligence and any consequent risk should be borne by shareholders, not consumers. However, these risks would have been known at the time JEN purchased the relevant network assets. Accordingly, such risks should not be deferred and passed on to network users

Most significantly, the AER also notes that that the RPP (s. 7A (3) of the NEL) states that the service provider must be provided with incentives to undertake (amongst other things) efficient investment in the network, and to undertake the efficient provision of direct control services. The AER considers that if such costs were passed through, this would ultimately mean that customers would be paying a higher level of costs than is efficient (or that would be charged by a competitive business, in which

[152] JEN, *Revised regulatory proposal,* pp. 300–301.
[153] ibid.

case it would not be viable for those costs to be passed on to customers). Further, the AER notes the NEO, which (amongst other things) seeks to promote efficient investment in, and efficient operation of electricity services for the *long term interests of consumers.*

The AER considers that permitting pass through costs associated with asbestos liability does not generally serve either the RPP or the NEO. Allowing costs to be passed through to customers, particularly when those risks were known at the time of purchase, can hardly be said to constitute an incentive for a DNSP to undertake *efficient investment* in the network. Further, it is unclear how allowing these costs to be borne by end users, rather than shareholders/owners, serves the long term interests of customers.

16.6.5.4 AER conclusion

The AER maintains its position in its draft decision to reject an asbestos compensation event.

16.6.6 Transmission costs pass through event

16.6.6.1 AER draft decision

This event was not proposed in any of the Victorian DNSPs' regulatory proposals. .

16.6.6.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor, JEN and United Energy all proposed that costs associated with transmission connection, avoided transmission use of system (TUOS) and inter DNSP charges be treated as pass through events, should the AER consider that these costs were not recoverable, or the AER did not accept proposed variations to the WAPC formula.[154] JEN, CitiPower and Powercor also proposed a materiality threshold of zero for this event.

16.6.6.3 AER issues and considerations

The previous regulatory regime allowed for the recovery of the avoided TUOS, inter-DNSP payments and transmission connection costs. The AER recognises that these are legitimate costs that attach to the DNSPs' provision of direct control services for which recovery is permitted under the current jurisdictional regulatory regime. At the time of this final decision, the AER acknowledges that there is uncertainty faced by the Victorian DNSPs about the recovery of these costs. While the AEMC's current rule change process is intended to address this apparent deficiency, the process has not been finalised at the time of publishing this decision.[155]

Whilst the above mentioned costs may be uncontrollable, the timing of these costs is known to some extent (for example, inter DNSP payments). A nominated pass through event is typically not the appropriate mechanism to recover these costs. Further, these costs are not insignificant, but are, individually, unlikely to be of such a

[154] CitiPower, *Revised regulatory proposal.* p. 413; JEN, *Revised regulatory proposal.* pp. 310–311; Powercor, *Revised regulatory proposal.* pp. 413–414; United Energy, *Revised regulatory proposal.* p. 330.

[155] See AEMC Rule change, DNSP recovery of transmission related charges, wwww.aemc.gov.au

high magnitude that they would undermine the financial viability of the DNSP or meet the materiality threshold.[156]

To effect the recovery of these costs in this interim period, the AER has decided to nominate an event that will occur annually on 31 May. The event is in respect of the total of the avoided TUOS, inter-DNSP payments and transmission connection costs a DNSP has incurred, up until 31 May of any one year or period during the forthcoming regulatory control period.[157] Each Victorian DNSP may then submit a pass through application seeking the approval of the AER to pass through a positive pass through amount or a negative pass through amount to distribution network users in accordance with clause 6.6.1 of the NER. This ensures that the AER is able to determine the approved pass through amount (or required pass through amount as the case may be) in time for those costs to form part of a Victorian DNSP's pricing proposal, which is due on 1 November of each regulatory year. relation to seeking to pass through these costs on 31 May 2014, the AER acknowledges that the actual annual costs for 2014 and 2015 will not be known. For this reason, the Victorian DNSPs may, in seeking to pass through these costs on 31 May 2014, provide as part of a written statement under clause 6.6.1(c), an estimated eligible pass through amount or required pass through amount (as the case may be) to be recovered in the last year of the 2011–15 regulatory control period.

The AER considers that allowing recovery of these costs will, or is likely to achieve the NEO by providing regulatory certainty to the Victorian DNSPs which is in the long term interests of consumers. This will also provide regulatory certainty, pending the finalisation of the AEMC's rule change process, consistent with the AEMC's intention in drafting the Chapter 6A regulatory framework.[158]

Further, the AER considers this will provide the Victorian DNSPs with a reasonable opportunity to recover at least the efficient costs they incur in providing direct control services, consistent with the RPP.

In considering how these costs should be recovered, the AER has also considered other options, specifically, an amendment to the WAPC formula or an opex allowance. For the reasons set out in chapter 4 and appendix L of this final decision, the AER considers that these means of providing cost recovery are either inappropriate or unavailable under the NER framework. The pass through mechanism is the only workable option for the recovery of these costs, pending a change to the NER as is in prospect by the AEMC. The AER notes that these costs will not be eligible for pass through, should they be recovered under new arrangements arising from the AEMC rule change.

The AER notes that pass throughs apply to the forthcoming regulatory control period. There are some adjustments that are made for 'unders and overs' associated with the

[156] For example, it is unlikely that the materiality threshold for a positive or negative change event would be met. This is a prerequisite for the pass through of costs to users pursuant to clause 6.6.1 of the NER.

[157] For the purpose of clause 6.6.1 of the NER, the eligible pass through amount is derived from the total of the avoided TUOS, inter-DNSP payments and transmission connection costs of any such year in a regulatory control period

[158] AEMC, Rule Determination , National Electricity Amendment (Economic Regulation of Transmission Services, Rule 2006 No. 18, 16 November 2006.

above costs. These have been historically passed through via the WAPC process (in the current regulatory period).[159] However, as the nominated pass through events only relate to events in the forthcoming regulatory control period, these ‘unders and overs’ cannot be the subject of pass through in this nominated pass through event.

16.6.6.4 AER conclusion

The AER has included a network charges pass through event as a nominated pass through for the forthcoming regulatory control period. The definition of this event is set out in the individual DNSPs' distribution determinations.

16.6.7 Premium feed in tariff costs event

16.6.7.1 AER draft decision

The AER, in its draft decision, considered the premium feed in tariff (PFIT) event. It stated:

> The AER notes that the AEMC is currently considering a rule change proposal which will allow DNSPs to include, in their form of control formula, a component to recover costs associated with premium feed in tariffs. …Subject to this process being finalised, the AER will provide for recovery of these costs in its final determination (to be published later in 2010) as part of the Victorian DNSPs' form of control formulas. Therefore, the AER rejects this event as a pass through event.[160]

16.6.7.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor and JEN noted the rule change in their revised regulatory proposals.[161] United Energy also appeared to propose this as a step change.[162]

16.6.7.3 AER issues and considerations

The AER notes that the final AEMC determination on the PFIT was made on 1 July 2010.[163] This allows cost recovery for jurisdictional schemes, including schemes associated with PFIT. Accordingly, the AER does not consider it appropriate that this be the subject of a nominated pass through event. However, the AER notes that other costs—incurred opex and capex costs, for example, or administrative costs—may be incurred with this event. The AER notes that EnergyAustralia has recently submitted a pass through application to the AER which characterises these costs as a 'service standard event' under the NER. The AER further notes that it is open to the Victorian DNSPs to seek cost recovery via the NER prescribed pass through event (as EnergyAustralia has done) when and if those costs arise.[164]

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159 The AER’s reasons for not treating these costs in the form of control formula are set out at chapter 4.

160 AER, *Draft decision*, p. 716.

161 JEN, *Revised regulatory proposal,* p. 302; Powercor, *Revised regulatory proposal,* p. 62.

162 JEN, *Revised regulatory proposal,* p. 93.

163 AEMC, *National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010 No. 7,* July 2010.

164 For the application submitted by EnergyAustralia, see www.aer.gov.au

16.6.7.4 AER conclusion

The AER maintains its draft decision, that is, to reject the PFIT costs event as a nominated pass through event.

16.6.8 Force majeure pass through event

JEN submitted that the force majeure event should be accepted. JEN argued that a force majeure event covers events that would not fall within the AER's natural disaster event. This includes events that may occur before the commencement of the next regulatory control period, and including activities such as war, riot and sabotage that would not be covered by the terrorism pass through event.[165] JEN asserts that the force majeure event would cover events that may occur before the commencement of the regulatory control period.[166]

16.6.8.1 AER issues and considerations

The AER has considered the definition of both natural disaster event and terrorism event. The AER notes that it did permit the force majeure event as part of its NSW distribution determination.[167] The AER accepts that the natural disaster event may not cover all events that are otherwise contemplated by the force majeure event proposed by JEN. The AER does accept that some events caused by human actions may not necessarily fall within the terrorism event in the NER, however, considers that the most serious actions would likely fall within this definition.

Notwithstanding the fact that the AER accepted this event in the NSW distribution determination, the AER notes that it has revised its assessment criteria for the approval of nominated pass through events. Further, the force majeure event did not (and does not) meet these revised criteria. The reasons for not approve the force majeure event are clearly set out that document.[168]

One of those criterion related to forseeability, that is, the event is foreseeable (in that the nature or type of event can be clearly identified). The force majeure event as proposed by JEN cannot be clearly identified in advance. It appears to be a 'catch all' event, similar to the general nominated pass through event that has been included in some previous AER distribution determinations but which has now been abandoned for reasons stated in the AER's draft decision and as discussed in further detail below. A force majeure event cannot be tightly defined in advance, and therefore, the force majeure event does not meet the AER's pass through assessment criteria.

16.6.8.2 AER conclusion

The AER maintains its draft decision, that is, to reject the force majeure event proposed by JEN.

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165 JEN, *Revised regulatory proposal*, p. 293.
166 ibid, p. 293.
167 AER, *NSW Distribution determination 2009–2014, final decision*, April 2009, pp. 267–297.
168 AER, *Draft decision*, pp. 711–718.

16.6.9 Financial failure of a retailer event

16.6.9.1 AER draft decision

The AER rejected the financial failure of a retailer event proposed in its draft decision. The AER considered that cl. 6.21 of the NER provided the Victorian DNSPs with sufficient power to seek prudential arrangements in the event of retailer failure.

16.6.9.2 Victorian DNSP revised regulatory proposals

The Victorian DNSPs asserted that this event should be accepted as a nominated pass through event.[169] The Victorian DNSPs cited the default Use of System Agreement (UoSA), which they are compelled to adhere to in accordance with their distribution licences. They submitted that the prudential requirements of cl. 6.21 of the NER were not sufficient to provide for cost recovery in the event of financial failure. Some DNSPs submitted that cl. 6.21 could not be invoked due to constraints within the UoSA. All five DNSPs stated that the credit support arrangements in the UoSA do not fully compensate for retailer failure.[170] This event was included as part of the ESC's 2006–2010 EDPR. CitiPower, Powercor and JEN each proposed that this event should carry a materiality threshold of zero.

16.6.9.3 AER issues and considerations

In its draft decision, the AER considered that prudential requirements could be sought for 'failure of a retailer costs'. Relevantly, cl. 6.21 of the NER allows DNSPs to seek a number of financial guarantees such as bank guarantees, prepayments or up front contributions. However, the AER notes the UoSA contains prescribed credit support arrangements which the DNSPs are compelled to follow under their licence agreements.

The AER does not accept that it would be impossible to recover these amounts under cl. 6.21 of the NER. This is because that clause provides broad opportunity for prudential requirements, even if an instrument is already in place to recover some (but not all) costs.

The AER accepts that historically, Victorian DNSPs have been able to pass through shortfalls arising from the operation of the UoSA. However, the AER notes that this was under the previous Victorian regulatory regime, which appears to provide more discretion for the regulator to allow the pass through of revenue impacts, and not just cost impacts. Several definitions for this event (as submitted by the Victorian DNSPs) contained references to losses of revenue.

The AER notes that 'positive change event' is defined at chapter ten of the NER. That definition provides that a positive change event for DNSPs relates to the 'increase in costs in the provision of direct control services that the DNSP has incurred'.[171] It is also clear that changes in revenue do not meet the definition of 'eligible pass through

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[169] CitiPower, *Revised regulatory proposal.* pp. 410–411; JEN, *Revised regulatory proposal.* pp. 299–300; Powercor, *Revised regulatory proposal,* pp. 410–411; SP AusNet, *Revised regulatory proposal.* pp. 353–354; United Energy, *Revised regulatory proposal.* p. 329.

[170] CitiPower, *Revised regulatory proposal.* pp. 410–411; JEN, *Revised regulatory proposal.* pp. 299–300; Powercor, *Revised regulatory proposal,* pp. 410–411; SP AusNet, *Revised regulatory proposal.* pp. 353–354; United Energy, *Revised regulatory proposal.* p. 329.

[171] NER, chapter 10.

amount' in Chapter 10 of the NER. This definition clearly excludes 'revenue impacts of an event'. Thus, even if the AER approved the financial failure of a retailer event, the AER would be unable under clause 6.6.1 of the NER to pass through amounts in respect of such event.

16.6.9.4 AER conclusion

For the reasons expressed above, the AER maintains its draft decision, that is, to reject the financial failure of a retailer event. In order for any shortfalls from the operation of the UoSA to be recovered, changes to the NER would be required.

16.6.10 Definition of insurance event

16.6.10.1 AER draft decision

The AER accepted the insurance event proposed by SP AusNet and JEN. The AER made some modifications to the definition of this event (noting that the initial definitions proposed by SP AusNet and JEN were different). The event is designed to allow for recovery of costs over and above any insurance caps for insurance payouts, where a claim is made to the DNSP's insurer.

16.6.10.2 Submissions

The AER received only one stakeholder submission on the insurance event, from the EUCV. The EUCV stated that the drafting permits the DNSPs to insure for a much lower amount than needed and, the DNSPs in doing so, would reduce their opex. In turn, the opex saving would be retained by the DNSPs. Accordingly, in the EUCV's opinion, the nominated pass through event, as currently drafted, would allow the DNSPs to pass on to consumers the over-run in costs.

16.6.10.3 Victorian DNSP revised regulatory proposals

JEN and SP AusNet both submitted that the AER's definition of insurance event required revision. Both considered that the AER's amended definition was too onerous and negated the application of the pass through. They submitted that conduct involving 'negligence, fault or lack of care' are motivators for taking out insurance.[172] SP AusNet stated that an insurance policy would not cover illegal or grossly reckless acts or omissions. Therefore, in the event of such conduct, the insurance policy would be invalidated and the cost pass through not invoked.[173] SP AusNet proposed that the exclusion provisions outlined in the definition should be removed. JEN proposed that its original definition of insurance event should be used.[174] JEN noted the AER's desire to create incentives to reduce costs above the insurance cap. However, it stated that the DNSP's efforts to mitigate costs are already implicit in the AER's assessment of pass through costs.[175]

Text removed [CIC]

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[172] JEN, *Revised regulatory proposal,* pp. 350–351; SP AusNet, *Revised regulatory proposal,* p. 350.

[173] SP AusNet, *Revised regulatory proposal,* p. 350.

[174] SP AusNet, *Revised regulatory proposal,* p. 350.

[175] JEN\, *Revised regulatory proposal,* pp. 350–351. JEN referred to cl. 6.6.1(j) of the NER, which requires the AER to have regard to the efficiency of costs incurred in relation to a positive change event.

16.6.10.4 AER issues and considerations

The AER notes the concerns of JEN and SP AusNet. The AER's intention, in including the exclusion provisions, was to ensure that:

- conduct that was illegal, or knowingly negligent, was not covered by the pass through definition.

- conduct that would invalidate an insurance policy was not covered by the pass through definition.

- in relation to the first point, the AER accepts SP AusNet's contention that conduct which is illegal, or a grossly reckless act or omission, is unlikely to be covered by an insurance policy. The AER also considers that there is merit in SP AusNet's comment that 'a claim against SP AusNet would be unlikely to be successful if the opposing party was unable to establish wrong doing or negligence.'[176]

- in relation to the second point, the AER accepts that, where an insurance policy was not paid, then the insurance cap pass through would not be invoked.

In relation to JEN's arguments, the AER reiterates its draft decision.[177] That is, costs beyond an insurance cap are eligible to be treated as a pass through event under the relevant provisions of clause 6.6.1 of the NER. In response to JEN's assertion that the AER can assess whether or not costs have been mitigated under cl. 6.6.1, the AER notes that the information asymmetry that exists between the regulator and the DNSP makes it difficult to make such an assessment. Therefore, whilst the AER has amended the definition of this pass through event, it has not reverted to JEN's proposed definition of insurance event.

- The AER notes the EUCV's concerns on the 'cost over-run issue'. However, the assessment of cost pass through amounts under cl. 6.6.1 of the NER compels the AER to assess the costs incurred by the DNSPs (where an event occurs), including any steps/actions the DNSPs have taken to mitigate incurred costs. The AER notes that it will not allow costs to be passed through to consumers where it considers those costs have not been incurred efficiently. The AER considers that the DNSPs are not incentivised to under-insure based on the interplay between self insurance and pass throughs discussed in more detail at section16.1 above

The AER has thus amended its definition of 'insurance cap' event to reflect the original wording contained in SP AusNet's and JEN's initial regulatory proposals, subject to the following addition.

In its discussion on insurance, the AER permitted this step change (see appendix L of this decision). However, the AER in that discussion noted that whilst it can permit increased insurance allowances, it cannot compel a DNSP to actually seek the

176 SP AusNet, *Revised regulatory proposal*, p. 350.
177 AER, *Draft decision*, p. 725.

increased coverage for which the premiums were sought. In this instance, the AER is concerned that customers could potentially pay twice—firstly, for increased premiums under the opex allowance, and secondly, through the pass through mechanism (the insurance event, whereby the DNSPs recover costs above its insurance cap. As part of the step changes appendix, the AER stated:

[CIC text removed]

The AER expects that, because an increase in coverage has been allowed for through opex for several DNSPs, the insurance cap pass through event should be amended for so that only costs beyond caps on policies sought in this decision can be recovered, should an insurance event occur.

16.6.10.5 AER conclusion

The AER has updated its definition of insurance event, in response to the concerns raised by JEN and SP AusNet in their revised regulatory proposals. The AER has allowed an opex step change for insurance for several DNSPs. Therefore, the definition of this event (as set out in the distribution determinations) relates to insurance policies for which the DNSP is providing opex as part of this final decision (that is, the 'insurance cap' that must be breached to trigger this event is the cap on the policies funded through the 2011–2015 opex allowances for each DNSP).

16.6.11 Rejection of general pass through event

CitiPower and Powercor did not accept the AER's rejection of the general pass through event.[178] Both DNSPs contended that the AER's approach is inconsistent with its previous distribution determinations. They also submitted that the AER's consideration in its draft decision on its transmission guideline on cost pass through was irrelevant and that given the difficulty in assessing distribution cost pass through, a general pass through event is needed.[179] In relation to the former, CitiPower and Powercor contended that the NER recognises a distinction between distribution and transmission.

178 CitiPower, *Revised regulatory proposal* pp. 409–410; Powercor, *Revised regulatory proposal*, pp. 409–410.
179 ibid.

United Energy also proposed that the AER accept the general pass through event for the Victorian DNSPs. It maintained that a failure to do so would result in inconsistency with other jurisdictions and that it would be unreasonable for the AER to refuse this event for the Victorian DNSPs.[180] It also disputed the AER's 'reliance' on the foreseeability assessment criterion in rejecting the general pass through event. It also cited the inability of DNSPs to reopen determinations (as distinct from TNSPs) to manage unexpected costs during the period. United Energy also stated that in the absence of a general pass through event, more nominated events were required.[181]

16.6.11.1 AER issues and considerations

For the reasons set out in the draft decision, the AER disagrees with the submissions of CitiPower, Powercor and United Energy.[182] Those reasons address the concerns expressed by the DNSPs regarding the lack of a 'reopener' for DNSPs.[183]

The AER makes the following additional points in response to the DNSPs' submissions.

In terms of inconsistency with other jurisdictions for which AER distribution determinations are already in force, the AER notes that any change in its regulatory approach necessarily results in some inconsistency across jurisdictions for a finite period. This is because regulatory control periods (and applicable distribution determinations) are not concurrent across jurisdictions and do not have uniform commencement dates. The AER notes that its regulatory approach will evolve over time. The AER is undertaking the first cycle of distribution determinations. As such, it is accepted the positions may take some time to settle, however, once those positions are settled they may be codified. Accordingly, it is also not unreasonable for the AER to refuse a general pass through event in this distribution determination. At this time, and unless there is good reason for the reintroduction of such event, the AER intends that its refusal of the general pass through event will apply in future distribution determinations.

While the AER acknowledges that the exclusion of the general pass through event may appear inconsistent with its approach in previous determinations, the AER considers that its revised approach maintains adequate coverage for uncontrollable costs. The AER does not anticipate that this will lead to any major differences in likely outcomes. The AER further notes that Victorian DNSPs gain a natural disaster pass through event.

The AER also considers that the lack of a previously consistent approach to defining pass throughs across jurisdictions is not evidence of a need for a general pass through event. The AER also disagrees with the submission that there is difficulty in assessing distribution cost pass throughs and determining the appropriateness of events. The NER does provide an opportunity for additional pass through events to be nominated. However, the AER does not consider that this is because there is inherent difficulty in defining distribution cost pass through events in advance. Rather, this is likely an acknowledgment by the policy makers that DNSPs have been previously been subject

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180 United Energy, *Revised regulatory proposal,* pp. 327–328.
181 ibid.
182 AER, Draft Decision, pp. 718–720.
183 ibid., pp. 718–720.

to different regulatory arrangements, and that additional events (beyond the NER prescribed events) may be necessary to preserve incentive arrangements, or to address transitional issues. It does not mean that DNSPs should be subject to 'catch all' pass through events that are not defined in advance. Particularly, the AER does not consider this necessary for the Victorian DNSPs, who have not been subject to a general pass through event under the current jurisdictional regulatory regime. The AER reiterates that the ESC considered, and rejected, a general pass through event for the Victorian DNSPs. [184]

United Energy stated that, in the absence of a general pass through event, more nominated pass throughs are required for the Victorian DNSPs.[185] CitiPower and Powercor submit that DNSPs should not be left out of pocket for uncontrollable events which arise during the regulatory control period.[186] The AER considers that the number of nominated pass though events is irrelevant, rather, it is the coverage of the nominated events that is more important. Having more nominated pass through events is not preferable unless those pass through events are required in order to meet the NEO and RPP and are in accordance with the overarching incentive framework. None of the relevant DNSPs' submissions have demonstrated why a greater number of nominated events is necessary to meet the NEO and RPP nor why they are justified under the incentive framework.

The AER disagrees with United Energy's suggestion that it should not have had regard to 'foreseeability' in rejecting the general pass through event.[187] For the reasons identified in the draft decision, the AER considers that this is a relevant consideration.

As stated above, the AER's draft decision considered in some detail the argument regarding the lack of a reopener provision for DNSPs. While the AER acknowledges that there is no reopener provision for DNSPs under the NER, the AER does not consider that this is a reason to necessarily allow an 'all encompassing' event for DNSPs. Due to the geographical nature and relative size of transmission networks, it is understood that they are more susceptible to natural disasters and other catastrophic events. In any case, the AER has nominated a natural disaster pass through event in this distribution determination.

The AER also disagrees with the submission of CitiPower and Powercor that the AER's consideration of its transmission pass through guideline was irrelevant or an irrelevant consideration.[188] Notwithstanding the DNSPs' submissions, aspects of the guideline cited in the draft decision apply equally to DNSPs and TSNPs, particularly points concerning regulation, a regulator's judgment and the incentive framework. In addition, the AER notes that the guideline was but one factor it took into account it its reconsideration of the general pass through event. For example, the AER also had regard to SCO documents and the approach taken by the ESC. The AER also refers to the discussion of transmission in section 16.1 of this chapter.

[184] ESCV, *EDPR, 2006–10, Vol. 1, October 2006, pp. 489–490*
[185] United Energy, *Revised regulatory proposal,* pp. 327–328.
[186] CitiPower, *Revised regulatory proposal* pp. 409–410; Powercor, *Revised regulatory proposal,* pp. 409–410.
[187] United Energy, *Revised regulatory proposal,* pp. 327.
[188] CitiPower, *Revised regulatory proposal* pp. 409–410; Powercor, *Revised regulatory proposal,* pp. 409–410; United Energy, *Revised regulatory proposal,* pp. 327–328.

16.6.11.2 AER conclusion

The AER maintains its draft decision, that is, not to apply a general pass through event for the 2011–2015 regulatory control period.

16.7 AER conclusion

The AER approves the following nominated pass through events for the forthcoming 2011—2015 regulatory control period:

- A declared retailer of last resort event
- An insurance cap event
- A network charges pass through event
- An insurer credit risk event.[189]

These events will carry a materiality threshold of one percent of annual revenue, for the reasons set out at section 16.1 above. The AER considers this threshold to be consistent with the NEO and RPP.

The AER further confirms that the following events will be treated as regulatory change events, where they substantially affect the manner in which direct control services are provided, and where they meet the requirement to materially increase or decrease the cost of providing direct control services:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework/a transfer of customer regulation to national regulatory framework event
- changes to safety regulations introduced by the ESV/changes to bushfire mitigation framework
- changes to exposure limits
- an emissions trading scheme event/ a CPRS event
- an ESMS event

The AER considers that the following event will be a tax change event under the NER:

- an AEMO fees and charges event .

[189] The definitions of these events can be found in the AER's distribution determinations for each individual DNSP. These are the distribution determinations for CitiPower, Powercor, JEN, SP AusNet and United Energy for the 2011–2015 regulatory control period. All definitions are identical, save for the insurance cap event for SP AusNet. These can be found on the AER's website at www.aer.gov.au.

The AER rejects the force majeure event, general pass through event, transmission costs event, asbestos compensation event and financial failure of a retailer event proposed by the Victorian DNSPs.

The AER has updated the definitions of insurance cap event, and insurer credit risk events in response to the Victorian DNSPs' revised regulatory proposals.

17 Demand management incentive scheme

17.1 AER draft decision

This chapter sets out the AER's final decision on how it will apply the demand management incentive scheme (DMIS) to CitiPower, Powercor, Jemena Electricity Networks (JEN), SP AusNet and United Energy in the forthcoming regulatory control period. [1]

The objective of the DMIS is to provide incentives for distribution network service providers (DNSPs) to seek out and implement efficient and innovative non-network solutions in response to growing demand and network constraints, as they arise in the network. The DMIS operates in conjunction with existing incentives on the regulatory framework. Whilst demand management programs can be funded through operating expenditure (opex) and capital expenditure (capex) where they meet the relevant capex and opex criteria and factors under the National Electricity Rules (NER), the DMIS aims to provide scope for new and innovative demand management solutions.

Clause 6.6.3(a) of the NER states that:

> The AER may, in accordance with the distribution consultation procedures, develop and publish an incentive scheme or schemes (demand management incentive scheme) to provide incentives for Distribution Network Service Providers to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way.

A decision on how the DMIS will apply to a DNSP is a constituent decision of a distribution determination, under clause 6.12.1(9) of the NER.

Under clause 6.4.3(a)(5) of the NER, a DNSP's annual revenue requirement for each regulatory year of the regulatory control period must be determined using a building block approach, including the revenue increments or decrements (if any), arising from the application of the DMIS. Further, under clause 6.3.2(a)(3) of the NER, the AER, in making a building block determination for a DNSP, must specify how the applicable DMIS is to apply to a DNSP.

The AER published its DMIS to apply to the Victorian DNSPs in April 2009.[2]

Part A of the DMIS is the demand management innovation allowance (DMIA). The DMIA is a 'use it or lose it' allowance provided to the DNSPs through their building block requirement. Part B of the DMIS is the forgone revenue component, which permits the DNSP to recover lost revenue arising from successful implementation of the DMIA.

This allowance is provided to the DNSPs to undertake new and innovative demand management projects as opportunities arise. The draft decision provided the following annual DMIA amounts (real $2010) for the Victorian DNSPs:

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1 This is the AER's DMIS to apply to CitiPower, Powercor, JEN, SP AusNet and United Energy. This DMIS was published in April 2009, and is available at www.aer.gov.au.

2 ibid.

- CitiPower—$200 000
- Powercor—$600 000
- JEN—$200 000
- SP AusNet—$600 000
- United Energy—$400 000.[3]

The AER also decided to apply Part B of the DMIS (the forgone revenue component) to the Victorian DNSPs for the forthcoming regulatory control period. Part B of the DMIS is a forgone revenue component, which allows a DNSP to recover forgone revenue as a result of successful, approved demand management initiatives under the DMIA, where these result in lower energy throughput (and hence, lost revenue) for the DNSP. This component was designed to interact with certain forms of price control under which revenue is directly determined by the throughput level (for example, a weighted average price cap, or WAPC).

17.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor and JEN accepted the AER's draft decision on the application of the DMIS and incorporated the draft decision into their revised regulatory proposals.[4]

SP AusNet accepted the AER's application of the DMIS as set out in its draft decision. SP AusNet also proposed $10.94 million of additional expenditure for demand management and non network initiatives. This was outlined in both SP AusNet's original regulatory proposal and revised regulatory proposal.[5] This expenditure is considered as part of SP AusNet's broader opex program.

United Energy appeared to accept the AER's draft decision on application of the DMIS.[6] United Energy clarified that additional expenditure sought in its original regulatory proposal for general non network alternatives was not intended to be considered as part of the DMIS. United Energy confirmed in its revised regulatory proposal that it is seeking a further $10 million as part of its broader opex allowance to undertake demand management programs (outside the DMIS).[7]

17.3 Submissions

The AER received four submissions on the application of the DMIS to the Victorian DNSPs. These were from:

- EnergyAustralia

[3] AER, *Victorian distribution determination 2011–15*, *Draft decision,* 4 June 2010, p. 736.
[4] CitiPower, *Revised regulatory proposal 201 to -2015*, 21 July 2010, p. 33; Powercor, *Revised regulatory proposal 2011 to 2015*, 21 July 2010, p. 31; JEN, *Revised Regulatory Proposal 2011–15*, 20 July 2010, p. 313.
[5] SP AusNet, *Electricity Distribution Price Review Revised Regulatory Proposal*, July 2010, pp. 263–269.
[6] United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011 – December 2015,* July 2010, pp. 307–309.
[7] ibid., pp. 307–321.

- Energy Response
- Victorian Employers Chamber of Commerce and Industry (VECCI)
- Total Environment Centre (TEC)
- EnergyAustralia submitted that:

> We note the AER has not developed a scheme which provides a positive incentive for distributors to undertake demand management to defer capital projects, or an allowance for these types of projects. We note that NSW distributors are subject to a d-factor scheme that provides an incentive payment for undertaking demand management projects that defer capital expenditure. While we note there are complexities in such a scheme, and current issues with the recovery of these payments, that the d-factor nevertheless provides EnergyAustralia with additional incentives to pursue DM opportunities.[8]

Energy Response noted that the current amount of the DMIA is modest, and that where pilots and trials have been proposed for non-network alternatives above the DMIA, they should be supported through ex ante opex.[9] Energy Response also expressed concern with the interaction of the DMIS with the service target performance incentive scheme (STPIS):

> … the S Factor may act as a major disincentive in the consideration of non-network solutions. …. an exclusion for the DBs from the service performance incentive scheme for aggregated DSR programs would assist in the uptake of Demand Management programs overall. At a minimum, a relaxation of these conditions until such time as the DBs get a better appreciation of whether there is or isn't a material risk with the implementation of an aggregated DSR program, would assist.[10]

SP AusNet also made similar comments on this issue, which are discussed in more detail in chapter 15.

VECCI stated:

> we are concerned that the overall approach to demand management is disjointed. For example in Victoria, an Energy Efficiency Target (VEET) scheme is already in place for households. There is a possibility the VEET may be replaced in the event of a national scheme, but its extension to small business is being considered by the State Government and suggests that an energy efficiency scheme of some description will apply to small business over the period until 2015….VECCI suggests there would appear to be advantages in concentrating demand management resources and that retailers are already subject to demand management obligations under their retail licences (and in the future under the National Energy Customer Framework).[11]

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8 EnergyAustralia, *Energy Australia submission on AER draft regulatory determination for Victorian distributors*, 19 August 2010, p. 17.

9 Energy Response, *Submission to the AER - Draft decision and draft determinations for the Victorian DBs*, 17 August 2010, p. 2.

10 ibid., p. 2.

11 VECCI, *Submission to the AER draft decision on Victorian distribution network tariffs for 2011–15*, 26 August 2010, pp. 15–16.

VECCI recommended that the AER reconsider the merits of allowing funding for DMIS, given the possibility this is dispersing demand management efforts, and the need to move Advanced Metering Infrastructure (AMI) outcomes to ensure that costs do not exceed benefits.[12]

TEC stated:

> United Energy has stated that its allowance of $400 000 per year is insufficient to enable it to undertake even small scale demand management projects and has proposed an increase in the amount of the DMIA to a total of $10 million for United Energy over the forthcoming regulatory control period.8 SP AusNet's proposal for an extra $3.2 million above the DMIA for technology trials also demonstrates the inadequacy of the DMIA.[13]

17.4 Issues and AER considerations

The AER notes that each of the Victorian DNSPs accepted the application of part A and part B of the DMIS, including the DMIA amounts included as part of the AER's draft decision.

Regarding the issues above raised by stakeholders, the AER notes that these issues have been previously considered by the AER through public consultation when the DMIS was developed.

In relation to the d-factor, and as previously discussed, the AER accepts that there is merit in applying a d-factor style scheme for DNSPs.[14] However, the decision to apply a d-factor scheme for NSW DNSPs was largely made to continue the incentive arrangements created by Independent Pricing and Regulatory Tribunal (IPART), which had previously applied a d-factor to the NSW DNSPs. The AER intends to continue to monitor the outcome of this scheme throughout the NSW DNSPs' 2009–14 regulatory control period.

The TEC has raised the inadequacy of the DMIA funding, stating that it is not enough to meet the level of demand management. EnergyAustralia also noted that the DMIA is modest. Again, the AER reiterates that demand management funding can be funded through opex and capex allowances, and indeed, the Victorian DNSPs have sought such funding as part of their revised proposals. The AER further notes that the DMIA is able to fund largely untested non network initiatives. Little empirical evidence has been gathered on customers willingness to pay for such initiatives. Since customers effectively fund the DMIA, it would be inappropriate to increase the amount provided for untested initiatives.

Whilst the AER cannot compel the uptake of non-network alternatives under the NER, it can consider such programs (where put forward by a DNSP in its regulatory proposal) as part of the DNSP's ex ante opex allowance.

12 ibid., pp. 15–16.

13 TEC, *Submission to AER on draft decision Victorian distribution network service providers 2011–2015*, 24 August 2010, p. 8.

14 This issue was discussed extensively in the AER's DMIS for Victorian DNSPs, see pp. 11–12. The AER's DMIS and final decision was published in April 2009 and can be found at www.aer.gov.au.

TEC asserts that AER failed to take into account demand management initiatives proposed by SP AusNet and United Energy. The AER notes that SP AusNet and United Energy have proposed non network alternatives as part of their revised regulatory proposals (for example, direct load control for air conditioning and hot water system timing) which are discussed in more detail at appendix L of this draft decision.

In its revised proposal, SP AusNet stated that it did not consider that the AER has had adequate regard to clause 1.5(b)(7) of the STPIS which states that the AER will have regard to the possible effects of the scheme on incentive for the implementation of non-network alternatives.

In support of a demand management exclusion from the STPIS, Energy Response submitted that the STPIS may act as a disincentive to DNSPs' considerations of non network demand management solutions.

The AER's view on this matter has not changed from its draft decision. In reaching this conclusion the AER has had regard to clause 1.5(b)(7) as well as the other objectives of the scheme, including clauses 1.5.(b)(1) and (6). While Energy Response's comments are acknowledged, there have been no further views put forward or information provided which the AER considers would necessitate a change in the STPIS to exclude the DMIS.

Regarding the issue raised by Energy Response and SP AusNet on the interaction of the DMIS and the STPIS, the AER notes that this was considered both in the development of the STPIS and the draft determination for the Victorian DNSPs. In the former document, the AER noted:

> The AER considers that such an adjustment to the STPIS, which is fundamentally intended to maintain or improve service performance, would be inappropriate as customers should not be worse off in terms of the level of service performance they receive due to the implementation of non-network alternatives. The AER has therefore not included an exclusion for non-network alternatives as it intends that the STPIS be as neutral as possible regarding the level of reliability provided by network solutions vis-à-vis non network alternatives.
>
> The AER considers that the risks associated with the reliability of a non-network alternative should be managed by a DNSP as it is the party best able to manage that risk through the commercial arrangements it establishes in relation to non-network alternatives.[15]

In the AER's draft decision, it stated:

> The AER's position is also supported in a recent report on demand side management by the Australian Energy Market Commission (AEMC).[16] In its report, the AEMC noted that the current service incentive arrangements for distribution networks do not provide a barrier to demand side participation. The AEMC stated that service incentive schemes allow DNSPs to appropriately compare levels of reliability and continuity of

[15] AER, *Final Decision on Service Target Performance Incentive Scheme*, June 2008, p. 19. www.aer.gov.au

[16] AEMC, *Market Review of Demand Side Participation in the NEM, Stage 2 Final Report*, December 2009 p. 32.

supply with likely penalties or benefits. The AEMC stated that demand management options:

> will be considered, if they can improve reliability at relatively low cost rather than being summarily dismissed if they are considered less reliable. Rather, the possible penalty from a lower level of reliability will be considered and valued compared to the cost of the option and possible benefit. Therefore, if the cost of the DSP option is sufficiently low, and the risk of it impacting on the quality of supply can also be managed at a low cost, the network owner will prefer the DSP option.[17]

The AER is not aware of any compelling evidence that would lead it to alter its position on this matter. Consistent with the STPIS, the AER will therefore not exclude non-network alternatives from data collected for the purposes of applying the STPIS.[18]

The AER's view on this matter has not changed. Whilst Energy Response's comments are acknowledged, there have been no further views put forward or information provided which the AER considers would necessitate a change in the STPIS to exclude the DMIS.

On the issues raised by VECCI, the AER notes that some transitional issues have arisen in moving from the current regulatory regime to the national framework. However, it considers that specific programs that are in place in Victoria (for example, the VEET scheme as noted by VECCI) do not necessarily conflict with the intent of the DMIS. Although VECCI raise issues with the implementation of a separate DMIS scheme (and state that there is more benefit in extending the current VEET scheme instead), the AER notes that the intent of the DMIS is to enable the DNSP to implement demand management opportunities as they arise through the regulatory control period. It is not to limit the types of opportunities that DNSPs may respond to. Further, the AER does not consider it necessary to claw back or reconsider DMIA allowances in light of AMI realised efficiencies. The AER notes that there are opportunities for non network alternatives (which the DMIS may fund) beyond those arising from the rollout of AMI.

17.5 AER conclusion

In accordance with clause 6.12.1 (9) of the NER, the AER's final decision on the application of the DMIS is to:

- apply Part A (the DMIA) of the DMIS to the Victorian DNSPs
- apply Part B (the forgone revenue component) of the DMIS to the Victorian DNSPs.

The DMIA amounts (real $2010) for each Victorian DNSP for the forthcoming regulatory control period are:

- CitiPower—$200 000 ($1 million over the regulatory control period)

17 ibid., p. 32.
18 AER, *Draft decision*, p. 658.

- Powercor—$600 000 ($3 million over the regulatory control period)
- JEN—$200 000 ($1 million over the regulatory control period)
- SP AusNet—$600 000 ($3 million over the regulatory control period)
- United Energy—$400 000 ($2 million over the regulatory control period).

The AER notes that although these amounts are allocated annually through the building block mechanism, the DNSP can use these funds at any point in the regulatory control period to pursue initiatives under the DMIS.

18 Building block revenue requirements

This chapter sets out the AER's calculation of annual revenue requirements for the Victorian DNSPs for the provision of standard control services for each regulatory year of the forthcoming regulatory control period. It also sets out the X factors to be applied as part of the weighted average price cap (WAPC) to apply to the standard control services provided by each Victorian DNSP.

18.1 Regulatory requirements

Clause 6.3.2(a) of the National Electricity Rules (NER) states that the AER's building block determination must specify:

> (1) the DNSP's annual revenue requirement for each regulatory year of the regulatory control period;
>
> (2) appropriate methods for the indexation of the regulatory asset base (RAB);
>
> (3) how any applicable efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS) or demand management incentive scheme (DMIS) are to apply to the DNSP;
>
> (4) the commencement and length of the regulatory control period;
>
> (5) any other amounts, value or inputs on which the building block determination is based

Clause 6.5.9 of the NER requires a building block determination to include the X factor for each year of the regulatory control period. The AER must set the X factor with regard to the DNSP's total revenue requirement for the period. The X factor must be set to equalise (in net present value terms) the revenue to be earned from the provision of standard control services with the total revenue requirement attributable to those services. The X factor must also minimise variance between expected revenue and the annual revenue requirement for the last year of the regulatory control period.

A DNSP's building block proposal must be prepared in accordance with the AER's post-tax revenue model (PTRM) and the requirements of Part C of chapter 6 and Schedule 6.1 of the NER. The building block proposal must also comply with the requirements of any relevant regulatory information instrument, such as a regulatory information notice (RIN).

Clause 6.11.2(3) of the NER requires the AER to publish its reasons for its final constituent decisions made in accordance with rule 6.12. The constituent decisions dealt with in this chapter are:

- a decision to approve or refuse to approve the annual revenue requirement for the DNSP[1]
- decisions on other appropriate amounts, values or inputs[2]

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1 NER, cl.6.12.1(2)(i)

- a decision on the X factor (as it relates to the control mechanism discussed in chapter 4)[3]

Under clause 6.12.3(d) the AER must approve annual revenue requirements if it is satisfied that they have been properly calculated using the PTRM on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of chapter 6.

18.1.1 Annual building block revenue requirement

Clause 6.4.3(a) of the NER defines and details the building blocks that form the annual revenue requirement as:

- indexation of the RAB
- return on capital
- depreciation
- estimated cost of corporate income tax
- revenue increments or decrements arising from the AER's efficiency benefit sharing scheme (EBSS), service standards performance incentive scheme (STPIS) or demand management incentive scheme (DMIS)
- other revenue increments or decrements arising from the application of a control mechanism in the previous regulatory control period
- forecast operating expenditure (opex).

18.1.2 Post-tax revenue model

The PTRM published by the AER under clause 6.4.1 of the NER sets out how the annual revenue requirement is to be calculated. Clause 6.4.2 specifies that the PTRM must include:

- a method that is likely to result in the best estimates of expected inflation
- the timing assumptions and associated discount rates applicable to the calculation of building blocks in clause 6.4.3 of the NER
- the manner in which working capital is to be treated
- the manner in which the estimated corporate income tax is to be calculated.

A DNSP's building block proposals must be prepared in accordance with the AER's PTRM under clause 6.3.1.

2 NER, cl.6.12.1(10)
3 NER, cl.6.12.1(11)

18.2 AER draft decision

In accordance with clause 6.3.2(a) of the NER, the AER decided the annual revenue requirements for each regulatory year of the forthcoming regulatory control period for each Victorian DNSP as follows:

Table 18.1 AER draft decision on annual revenue requirements ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	208.2	206.0	222.0	240.8	250.6
Powercor	422.7	439.8	453.8	483.3	485.0
JEN	168.7	174.4	188.1	185.2	178.9
SP AusNet	452.2	379.4	414.2	451.7	407.1
United Energy	262.9	266.6	286.8	306.2	297.0

Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 771–772.

In accordance with clause 6.5.9 of the NER the AER decided the X factors for each regulatory year of the forthcoming regulatory control period for each Victorian DNSP as follows:

Table 18.2 AER draft decision on X factors (per cent)

	2011	2012	2013	2014	2015
CitiPower	7.27	0.00	0.00	–2.00	–2.00
Powercor	8.14	0.00	0.00	0.00	0.00
JEN	1.46	0.00	0.00	3.00	6.00
SP AusNet	4.46	0.00	0.00	0.00	0.00
United Energy	19.57	0.00	–2.00	–3.00	–5.00

Source: AER, *Victorian distribution determination 2011–15*, Draft decision, June 2010, pp. 771–772.

18.3 Victorian DNSP revised regulatory proposals

Tables 18.3 and 18.4 set out the revised revenue requirements and associated X factors proposed by CitiPower and Powercor respectively.

Table 18.3 CitiPower's revised regulatory proposal on annual revenue requirements and X factors ($'m, nominal)

	2011	2012	2013	2014	2015
Return on capital	132.6	148.6	165.6	184.7	203.4
Regulatory depreciation	34.8	38.6	42.7	46.9	52.4
Operating expenditure	52.7	54.4	57.6	59.1	63.4
Efficiency carryover amounts	0.0	0.0	0.0	0.0	0.0
S-factor amounts	0.2	– 2.9	– 3.4	– 0.2	– 7.3
Tax allowance	4.2	4.6	5.5	5.9	6.9
Annual revenue requirement	224.4	243.4	267.9	296.4	318.7
X factor (per cent)	– 7.27	– 4.00	– 4.00	– 4.00	– 4.00

Source: CitiPower, *Revised regulatory proposal*, pp. 427–428.

Table 18.4 Powercor's revised regulatory proposal on annual revenue requirements ($'m, nominal)

	2011	2012	2013	2014	2015
Return on capital	228.0	255.0	283.3	312.1	342.2
Regulatory depreciation	62.2	70.6	79.3	88.2	99.8
Operating expenditure	180.1	190.2	197.0	210.7	224.0
Efficiency carryover amounts	26.6	23.7	2.1	– 7.4	0.0
S-factor amounts	8.3	– 6.8	– 3.6	1.7	– 19.3
Tax allowance	3.9	4.8	6.0	7.2	9.0
Annual revenue requirement	509.1	537.5	564.1	612.5	655.7
X factor (per cent)	– 20.63	– 1.00	– 1.00	– 1.00	– 1.00

Source: Powercor, *Revised regulatory proposal*, pp. 428–429.

Table 18.5 sets out the revised revenue requirements and associated X factors proposed by JEN. In JEN's view, the AER's draft decision on X factors was not consistent with the AER's statement that the price path had been set to align the 2015 building block revenue requirement with JEN's 2015 forecast revenues.[4] JEN considered that its regulatory proposal better aligned JEN's expected revenues and its

4 JEN, *Revised regulatory proposal*, p. 316.

building block revenue requirement in each year of the forthcoming regulatory control period.

Table 18.5 JEN's revised regulatory proposal on annual revenue requirements ($'m, nominal)

	2011	2012	2013	2014	2015
Return on capital	78.9	88.6	99.3	108.4	116.5
Regulatory depreciation	27.0	32.9	39.5	45.4	45.5
Operating expenditure	70.2	69.6	71.3	78.9	86.4
Efficiency carryover amounts	15.0	11.4	14.2	– 2.1	– 3.1
S factor true-up	– 2.2	– 0.9	– 0.4	– 0.4	– 2.8
Tax allowance	2.0	2.7	3.7	5.4	5.4
Annual revenue requirement	190.9	204.3	227.5	235.5	247.9
X factor (per cent)	– 16.41	– 3.00	– 3.00	– 3.00	– 3.00

Source: JEN, *Revised regulatory proposal*, pp. 315–316.

Table 18.6 sets out the revised revenue requirements and associated X factors proposed by SP AusNet. SP AusNet stated that its revised regulatory proposal on X factors:

- minimised the variance between its revised revenue requirement in 2015 and its revised building block revenue requirement in 2015. It noted that, in previous decisions, the AER appeared to have a tolerance of +/- 3.8 per cent in minimising the variance.
- equalised the NPV of its total revised revenue requirement and the revised expected smoothed revenue requirement respectively in the forthcoming regulatory control period.[5]

Within these constraints, SP AusNet's revised proposal was to 'front end' its revenues as its "credit metrics are highly sensitive to the timing of revenue".[6] SP AusNet noted its:

> …credit metrics are more stressed at the start of the regulatory control period than at the end. This is not unexpected given the lingering effects of the global financial crisis over 2011 and 2012 are likely to result in higher than average funding costs at the start of the period. In addition, immediate step changes in opex related to bushfire mitigation further increase underlying costs at the start of the period.[7]

5 SP AusNet, *Revised regulatory proposal*, p. 364–365.
6 SP AusNet, *Revised regulatory proposal*, p. 14.
7 SP AusNet, *Revised regulatory proposal*, p. 364–365.

Table 18.6 SP AusNet's revised regulatory proposal on annual revenue requirements ($’m, nominal)

	2011	2012	2013	2014	2015
Return on capital	214.1	236.0	266.5	296.7	324.8
Regulatory depreciation	91.9	51.2	62.2	58.2	55.9
Operating expenditure	187.6	200.5	213.5	226.1	237.4
Efficiency carryover amounts	15.0	– 24.3	– 4.6	4.1	0.0
S-factor amounts	20.0	2.4	– 5.2	0.8	– 46.7
Tax allowance	6.0	0.0	0.0	0.0	0.0
Annual revenue requirement	534.5	465.8	532.4	586.0	571.4
X factor (per cent)	– 25.08	– 1.9	– 1.9	– 1.9	– 1.9

Source: SP AusNet, *Revised regulatory proposal*, pp. 363–365.

Table 18.7 sets out the revised revenue requirements and associated X factors proposed by United Energy.

Table 18.7 United Energy's revised regulatory proposal on annual revenue requirements ($’m, nominal)

	2011	2012	2013	2014	2015
Return on capital	142.9	159.5	175.6	189.7	199.3
Depreciation	41.4	49.7	60.8	71.2	79.5
Operating expenditure	135.3	135.0	136.3	139.1	142.3
Efficiency carry-over amounts	0.0	0.0	0.0	0.0	0.0
Tax allowance	11.0	12.8	16.2	21.0	25.6
Annual revenue requirement	330.6	357.0	388.9	421.1	446.6
X factor (per cent)	– 16.83	– 4.0	– 4.0	– 4.0	– 4.0

Source: United Energy PTRM.

18.4 Submissions

Submissions on the Victorian DNSPs' revenue requirements and X factors were made by Origin Energy, Consumer Utilities Advocacy Centre (CUAC), Victorian Employers' Chamber of Commerce and Industry (VECCI) and the Energy Users Association of Australia (EUAA).

Origin Energy welcomed the AER's inclusion of information showing the contribution of the various building block components to the X factors.[8] It urged the AER to publish similar information for other electricity and gas distribution determinations.

CUAC supported the AER's amendments to Victorian DNSPs' initial proposed revenue requirements. It considered the amendments were measured and appropriate.[9]

VECCI submitted on behalf of small businesses that they had limited ability to pass on electricity price increases. That is, price increases would likely be absorbed by the businesses themselves because the businesses were typically unable to invest in new energy saving assets.[10]

The EUAA expressed concern that electricity price increases in NSW and Queensland have created hardship for end-users and, therefore, the respective state economies. It urged the AER to have regard to the broader economic impacts of electricity price increases in making its determinations and to confirm key elements of its draft decision.[11]

18.5 Issues and AER considerations

This section analyses the factors contributing to the Victorian DNSPs' proposed X factors and other specific issues raised by stakeholders and the DNSPs.

Further details on the AER's consideration of the Victorian DNSPs' proposed opex, depreciation and corporate income tax is set out at chapters 7, 10 and 12 of this decision. The return on capital using the weighted average cost of capital (WACC) determined in chapter 11 is outlined here. The AER's decision on the Victorian DNSPs' capex allowances is discussed in chapter 8 and indirectly affects the building blocks discussed below.

18.5.1 Contribution to proposed X factors

Table 18.8 decomposes the DNSPs revised proposed X factors into various building block and other elements. For the purposes of comparison across the DNSPs, the data in this table has been calculated by assuming that X factors for years two to five of the forthcoming regulatory control period are equal to zero, hence all required price changes are applied in year one, or as the 'P 0'. The final row of the table shows the total price changes arising out of the DNSPs' initial regulatory proposals for comparison.

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8 Origin Energy Electricity Limited, *Victorian Electricity Distribution Draft Determination and Revised Proposals*, 19 August 2010, p. 3.

9 Consumer Utilities Advocacy Centre, *Submission in response to the AER draft electricity distribution determination for Victoria and the distribution businesses revised revenue proposals*, 19 August 2010, p. 1.

10 Victorian Employers' Chamber of Commerce and Industry, *Submission to AER draft decision on Victorian distribution network tariffs for 2011–15*, 26 August 2010, p. 7.

11 Energy Users Association of Australia, *Submission to the Australian Energy Regulator on its Draft Decision on the Revenue and Price Proposals by the Victorian Electricity Distributors for the Period 2011–2015*, August 2010, p. 8–10.

Table 18.8 Victorian DNSPs' revised regulatory proposals - per cent contribution to 'P 0'

	CitiPower	Powercor	JEN	SP AusNet	United Energy
P0	–7.2	–20.6	–16.4	–25.1	–16.8
X for years 2 to 5	–4.0	–1.0	–3.0	–1.9	–4.0
P0 (assume X2–5 = 0)	–15.5	–22.9	–23.0	–29.6	–25.7
Realignment of tariff revenue to costs in 2010	4.9	1.0	4.9	–5.7	8.6
Energy / demand forecasts	0.3	2.5	–2.6	3.5	–2.7
WACC (incl. franking)	–11.7	–10.1	–9.7	–11.2	–11.3
O & M	–4.1	–8.1	–5.9	–20.0	–10.2
Capex/depreciation	–6.0	–8.7	–9.1	–9.7	–7.1
Accelerated depreciation	0.0	0.0	0.0	0.0	–1.9
Efficiency carryover	0.0	–2.3	–5.1	0.5	0.0
ESC S factor removal	1.6	3.3	4.3	12.7	–1.2
Other	–0.5	–0.4	0.2	0.2	0.2
Total increase from 2010 - revised proposals	**–15.5**	**–22.9**	**–23.0**	**–29.6**	**–25.7**
Total increase from 2010 - initial proposals	–27.4	–34.0	–47.4	–61.3	–25.6

Note: Negative amounts correspond to price increases in the CPI–X equation.
Source: AER analysis.

On the cost side, the table shows each building block element described in section 18.1.1, calculated by assuming particular costs reflect 2010 levels.

'Realignment of tariff revenue to costs in 2010' refers to the level to which current prices need to be adjusted to align costs and revenues at the end of the current regulatory control period (that is, before changes in costs and revenues from 2011 are factored into prices). 'Energy forecasts' are also a driver of price (as opposed to cost) increases as sales quantities affect expected revenues, which are set with respect to the DNSPs' building block costs.

With respect to their initial proposals, the overall price increases arising out of the DNSPs' revised proposals have reduced markedly in the case of SP AusNet and JEN, and to a lesser extent for CitPower and Powercor. This change mainly reflects the DNSPs' responses to the AER's draft decision with respect to energy sales forecasts and related issues around assumed tariff reassignments. All of the DNSPs significantly reduced the assumed impact of time of use tariffs in their revised proposals. Furthermore, the building block calculations in SP AusNet's revised proposal did not incorporate any impacts arising from time of use tariffs in its energy sales forecasts as it proposed to deal with these through amendments to the weighted average price cap control mechanism.[12] Other reductions in price increases with respect to the DNSPs' initial proposals relate to a reduction in the WACC stemming from a lower market risk premium (from 8 to 6.5 per cent) and debt risk premium (4.71 to 4.28 per cent).

Interestingly, while the relative contributions of each driver have changed, the overall price increases arising from United Energy's initial and revised proposals are approximately the same.

General observations from table 18.8 with respect to the proposed price increases are similar to those made in the AER's draft decision on the DNSPs' initial regulatory proposals, namely:

- the biggest contributor to price increases from 2010 is the proposed nominal vanilla WACC of 10.29 per cent, compared to the 8.53 per cent derived from the Essential Services Commission of Victoria's (ESCV) 2006 determination. The difference of 1.76 per cent arises primarily because of the indicative debt risk premium of 4.28 per cent, compared to 1.425 per cent determined by the ESCV.[13]
- opex is a key driver for the increase in costs for both SP AusNet and United Energy
- capex and depreciation are also a significant contributors for cost increases across the DNSPs
- JEN’s proposed cost increase is affected by a higher reward for gains arising under the ESCV’s efficiency carryover mechanism
- SP AusNet has proposed significant cost increase despite been offset by a large penalty arising from S factor outcomes from the current regulatory control period.

18.5.2 General price impacts

In the context of the concerns expressed by several stakeholders, table 18.9 lists the real percentage increases in a typical residential customer’s annual bill as a result of the Victorian DNSPs' proposed X factors, in the first year of the forthcoming regulatory control period and the average change for each of the subsequent four years.

12 SP AusNet, *Revised regulatory proposal*, pp. 56-7.
13 *ESCV, Electricity Distribution Price Review 2006–10*, Volume 1, October 2006, p. 332; AER analysis.

Table 18.9 Victorian DNSPs' revised regulatory proposals cost increases for annual electricity bill ($, 2010)

	2011	2012 to 2015
CitiPower	34.6	19.2
Powercor	99.0	4.8
JEN	78.8	14.4
United Energy	80.8	19.2
SP AusNet	120.4	9.1

Note: Assumed end use bill of $1200 per year, of which 40 per cent is attributed to distribution costs.

The AER’s final decisions on the Victorian DNSPs’ X factors are listed in section 18.7 below. The corresponding impact of the AER’s decision on end use customer bills is presented in table 18.10.

Table 18.10 AER final decision on real cost increases on annual electricity bill ($, 2010)

	2011	2012 to 2015
CitiPower	-30.8	21.6
Powercor	0.5	16.2
JEN	23.9	14.4
United Energy	1.8	18.0
SP AusNet	48.0	21.6

Note: Assumed end use bill of $1200 per year, of which 40 per cent is attributed to distribution costs.

In the case of CitiPower, the AER's X factors result in price decreases in the first year of the forthcoming regulatory control period with increases in each remaining year. Conversely, the X factors determined for JEN and SP AusNet result in a once off increase in 2011 but then smaller increases in real terms thereafter. Clause 6.5.9(b) of the NER requires the AER's X factors to be such that the NPVs of the expected revenue and building block total revenue requirement for the forthcoming regulatory control period are equal, and that the difference between expected revenues and building block revenue requirements in 2015 are minimised. Within these requirements the AER is afforded some discretion in determining X factors which may vary across particular years of the forthcoming regulatory control period.

Under section 16 of the NEL, the AER must exercise its economic functions in a manner that will, or is likely to, contribute to the achievement of the national electricity objective. Under section 16(2) of the NEL, the AER must have regard to the revenue and pricing principles when exercising its discretion in making those parts of a distribution determination relating to direct control network services. When determining X factors within the scope of clauses 6.5.9(b)(1), (2) and (3) the AER has considered the need to provide DNSPs with a reasonable opportunity to recover at least efficient costs (including in particular regulatory years) and other relevant revenue and pricing principles, as well as the long term interests of consumers.

In this context the AER notes the concerns expressed by the EUAA and VECCI about the ability of some customers to absorb the large price increases implied from the Victorian DNSPs' proposals, which contrast from the real reductions in prices arising from the AER's draft decision.

The AER does not consider it has been provided with sufficient justification to incorporate SP AusNet's request to 'back end' its revenue requirements in order to address its 'credit metrics'. SP AusNet also did not specify what this task meant in terms of the AER's discretion in setting X factors. In a meeting with AER staff, SP AusNet provided a confidential presentation relating to benchmark cash-flows and credit rating information, however nothing was presented in relation to SP AusNet's actual repayments to debt holders or how this was affected by the lingering effects of the global financial crisis.[14] No information was presented on any new obligations for bushfire mitigation or associated cash-flow impacts as cited in SP AusNet's revised proposal.

Specific considerations on the X factors determined for each DNSP are outlined in section 18.7 below.

For comparison with table 18.8 above, the AER has decomposed the determinants of its draft decision X factors with respect to 2010 prices in table 18.11. As per table 18.8, the data in this table has been calculated by presuming that X factors for years two to five of the forthcoming regulatory control period are equal to zero, hence all required price changes are applied as a comparative once off price adjustment in 2011 (that is, the 'P 0').

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[14] SP AusNet, *SPA - Credit Metric Presentation Confidential*, provided via email to AER staff on 12 August 2010.

Table 18.11 AER final decision—per cent contribution to 'P 0'

	CitiPower	Powercor	JEN	SP AusNet	United Energy
P0 (assume X2–5 = 0)	**–1.4**	**–6.3**	**–11.0**	**–19.2**	**–5.6**
Realignment of tariff revenue to costs in 2010	6.5	4.1	9.3	–6.4	9.2
Energy / demand forecasts	0.9	2.9	–1.9	2.6	–0.3
WACC (incl. franking)	–5.0	–4.3	–6.6	–6.5	–3.9
O & M	–3.3	–6.1	–4.2	–12.1	–4.4
Capex/depreciation	–3.8	–8.0	–5.2	–10.0	–5.7
Accelerated depreciation	0.0	0.0	0.0	0.0	–1.8
Efficiency carryover	1.3	1.0	–6.1	1.0	0.0
ESC S factor removal	1.8	4.0	3.5	11.9	1.1
Other	0.2	0.2	0.2	0.2	0.1
Total increase from 2010 – Final Decision	**–1.4**	**–6.3**	**–11.0**	**–19.2**	**–5.6**
Total increase from 2010 – Draft decision	6.3	8.1	3.6	4.5	17.0

Note: Negative amounts correspond to price increases in the CPI–X equation

The data in table 18.11 indicate that the overall price increases resulting from the AER's final decision, with respect to 2010 prices, are mainly the result of:

- higher capex allowances compared to actual expenditures in the current regulatory control period
- some increases in opex, mostly stemming from new obligations in relation to bushfire mitigation
- an increase in the WACC (as per the DNSPs' revised proposals) ranging from 9.44 to 9.99 per cent, which is above the equivalent 8.53 per cent nominal vanilla WACC determined by the ESCV for the current regulatory control period. This mainly reflects an increase in the debt risk premium to a range of 3.7 to 4.1 per cent (from 1.425 per cent set by the ESCV).
- the AER's acceptance of slowing growth in energy sales.

JEN's and SP AusNet's prices earlier in the forthcoming regulatory control period are also affected by the rolling in of its capex overspends from the current regulatory control period (36 per cent and 30 per cent respectively). JEN’s prices are also affected by rewards under the ESCV's opex efficiency carryover scheme.

SP AusNet’s price increases are in spite of a large penalty arising from the S factor mechanism.

Aside from these penalties and rewards, the underlying building block revenue requirements of all the DNSPs rise steadily over the period, combined with slowing energy sales growth, contributing to further upwards pressure on average prices.

These price increases contrast to those provided for in the AER’s draft decision, with the differences mainly attributed to the recognition of higher capex and opex requirements, as well as a sizable reduction forecast energy sales in the final decision.

18.5.3 Other factors affecting price calculations

In converting the Victorian DNSPs' approved forecast capex allowances into the asset categories in the PTRM (including for tax purposes) the AER has applied the same percentage allocations used by the DNSPs in their revised regulatory proposals, which also reflected those used in the AER's draft decision.

The AER notes that none of the DNSPs commented on the AER's draft decision and reasons regarding the removal of assumed or forecast tariff reassignments in the PTRM's sales quantity inputs for the forthcoming regulatory control period.[15] The main reason for this decision was that the PTRM's calculations incorporate a simplifying assumption that customers all face the same price increases from what was in place in 2010 (being the latest year for which approved tariffs exist) arising from the uniform application of forecast inflation and X factors to each tariff component. Any assumed tariff reassignments violate this assumption and pre-empt the DNSPs' and the AER's decisions during the regulatory control period regarding the specific prices that might apply to each tariff component. That is, this simplifying assumption is intended to be revenue neutral to pricing decisions during the forthcoming regulatory control period that are made under the freedom and incentives of the weighted average price cap. Under this form of control mechanism, DNSPs are able to determine the specific tariff structures and prices that will apply in the case of TOU reassignments, with the expectation that prices will become more cost reflective. The AER has already accommodated an expected reduction in revenues arising from the mandated roll out of AMI by recognising that energy sales will decline over the period (thus resulting in higher allowed average price increases than would otherwise be the case). Similarly, the AER has accepted the DNSPs' expected impact on costs in the form of a modest reduction in peak demand arising from customer responses to AMI.

In the DNSPs' revised proposals, only SP AusNet's time of use modelling and United Energy's PTRM contained forecast reassignments related to the introduction of time of use tariffs and the mandated roll out of AMI. In requesting the remodelling of energy sales forecasts to reflect the AER's conclusions in chapter 6, the AER also requested any tariff reassignments not be reflected in updated PTRM inputs. The DNSPs' remodelling of energy forecasts, reflecting the AER's conclusions, has been incorporated in the final decision PTRMs and X factors.

[15] AER, draft decision, p. 756.

18.6 Summary of decision on building block components

This section provides a summary of the AER's decision for each DNSP with respect to the building block components listed in clause 6.4.3(a).

18.6.1 CitiPower

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of CitiPower's RAB to be $1287.3 million as at 1 January 2011. Based on this opening value, the AER has modelled CitiPower's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.12.

Table 18.12 AER forecast roll forward of CitiPower's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	1287.3	1407.8	1526.7	1662.5	1797.5
Net capital expenditure[a]	155.3	157.2	178.2	181.4	188.4
Indexation of opening RAB	33.1	36.2	39.3	42.8	46.3
Straight-line depreciation	-67.9	–74.6	–81.6	–89.3	–98.1
Closing RAB	1407.8	1526.7	1662.5	1797.5	1934.1

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that CitiPower's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to CitiPower's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.22.

The nominal vanilla WACC of 9.40 per cent is based on a pre-tax nominal return on debt of 8.81 per cent and a post-tax nominal return on equity of 10.28 per cent. These figures are calculated using CitiPower's agreed averaging period of 20 business days ending 27 August 2010.

Depreciation

As discussed in chapter 10, the AER has not approved CitiPower's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance.

Estimated taxes payable

Using the PTRM, the AER has modelled CitiPower's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than CitiPower's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Table 18.13 shows the AER's estimate of CitiPower's tax payments.

Table 18.13 AER modelling of CitiPower's net tax allowance ($'m, nominal)

	2011	2012	2013	2014	2015
Tax payable	12.5	13.5	14.7	15.4	16.8
Value of imputation credits	–6.3	–6.7	–7.4	–7.7	–8.4
Net tax allowance	6.3	6.7	7.4	7.7	8.4

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for CitiPower of $248.1 million (nominal) during the forthcoming regulatory control period, which is $39.1 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts arising from the ESCV's S factor and carryover mechanisms is a total of –$30.5 million (nominal), compared to the –$13.7 million proposed by CitiPower.

18.6.2 Powercor

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of Powercor's RAB to be $2212.8 million as at 1 January 2011. Based on this opening value, the AER has modelled Powercor's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.14.

Table 18.14 AER forecast roll-forward of Powercor's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	2212.8	2422.4	2629.0	2843.0	3072.9
Net capital expenditure[a]	271.7	276.5	291.9	316.2	329.2
Indexation of opening RAB	57.0	62.4	67.7	73.2	79.1
Straight-line depreciation	–119.1	–132.3	–145.6	–159.5	–176.0
Closing RAB	2422.4	2629.0	2843.0	3072.9	3305.2

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that Powercor's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to Powercor's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.23.

The nominal vanilla WACC of 9.40 per cent is based on a pre-tax nominal return on debt of 8.81 per cent and a post-tax nominal return on equity of 10.28 per cent. These figures are calculated using Powercor's agreed averaging period of 20 business days ending 27 August 2010.

Depreciation

As discussed in chapter 10, the AER has not approved Powercor's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance.

Estimated taxes payable

Using the PTRM, the AER has modelled Powercor's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Powercor's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause

6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Table 18.15 shows the AER's estimate of Powercor's tax payments.

Table 18.15 AER modelling of Powercor's net tax allowance ($'m, nominal)

	2011	2012	2013	2014	2015
Tax payable	25.0	25.8	28.2	30.0	32.8
Value of imputation credits	–12.5	–12.9	–14.1	–15.0	–16.4
Net tax allowance	12.5	12.9	14.1	15.0	16.4

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for Powercor of $866.0 million (nominal) during the forthcoming regulatory control period, which is $136.0 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by Powercor under the ESCV's S factor and carryover mechanisms have been reduced to –$56.9 million (nominal) from the $25.3 million proposed.

18.6.3 JEN

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of JEN's RAB to be $756.5 million as at 1 January 2011. Based on this opening value, the AER has modelled JEN's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.16.

Table 18.16 AER forecast roll-forward of JEN's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	756.5	812.4	875.8	936.9	1001.0
Net capital expenditure[a]	82.5	95.1	98.8	107.1	99.3
Indexation of opening RAB	19.5	20.9	22.6	24.1	25.8
Straight-line depreciation	–46.1	–52.6	–60.2	–67.2	–68.7
Closing RAB	812.4	875.8	936.9	1001.0	1057.4

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that JEN’s proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to JEN’s opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.24.

The nominal vanilla WACC of 9.95 per cent is based on a pre-tax nominal return on debt of 9.35 per cent and a post-tax nominal return on equity of 10.85 per cent. These figures are calculated using JEN's agreed averaging period of 30 business days ending 31 May 2010.

Depreciation

As discussed in chapter 10, the AER has not approved JEN’s proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance.

Estimated taxes payable

Using the PTRM, the AER has modelled JEN's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than JEN's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Table 18.17 shows the AER’s estimate of JEN’s tax payments.

Table 18.17 AER modelling of JEN's net tax allowance ($’m, nominal)

	2011	2012	2013	2014	2015
Tax payable	5.8	6.8	8.9	11.0	11.9
Value of imputation credits	–2.9	–3.4	–4.4	–5.5	–5.9
Net tax allowance	2.9	3.4	4.4	5.5	5.9

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for JEN of $308.1 million (nominal) during the forthcoming regulatory control period, which is $61.5 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by JEN under the ESCV's S factor and carryover mechanisms have been increased to $46.2 million (nominal) from the $35.4 million proposed.

18.6.4 SP AusNet

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of SP AusNet's RAB to be $2074.9 million as at 1 January 2011. Based on this opening value, the AER has modelled SP AusNet's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.18.

Table 18.18 AER forecast roll-forward of SP AusNet's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	2074.9	2279.2	2535.5	2799.0	3064.9
Net capital expenditure[a]	295.4	307.5	325.8	323.9	326.5
Indexation of opening RAB	53.4	58.7	65.3	72.1	78.9
Straight-line depreciation	–144.5	–109.8	–127.5	–130.2	–134.0
Closing RAB	2279.2	2535.5	2799.0	3064.9	3336.3

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that SP AusNet's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to SP AusNet's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.25.

The nominal vanilla WACC of 9.65 per cent is based on a pre-tax nominal return on debt of 9.19 per cent and a post-tax nominal return on equity of 10.34 per cent. These figures are calculated using SP AusNet's agreed averaging period of 20 business days ending 8 October 2010.

Depreciation

As discussed in chapter 10, the AER has not approved SP AusNet’s proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance.

Estimated taxes payable

Using the PTRM, the AER has modelled SP AusNet's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than SP AusNet's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Table 18.19 shows the AER’s estimate of SP AusNet’s tax payments.

Table 18.19 AER modelling of net tax allowance ($’m, nominal)

	2011	2012	2013	2014	2015
Tax payable	22.3	5.8	10.3	8.4	7.9
Value of imputation credits	–11.1	–2.9	–5.1	–4.2	–3.9
Net tax allowance	11.1	2.9	5.1	4.2	3.9

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for SP AusNet of $928.4 million (nominal) during the forthcoming regulatory control period, which is $136.8 million less than proposed.

Revenue decrements arising from previous periods’ control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by SP AusNet under the ESCV’s S factor and carryover mechanisms have been reduced to –$57.2 million (nominal) from the –$38.5 million proposed.

18.6.5 United Energy

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of United Energy’s RAB to be $1380.2 million as at 1 January 2011. Based on this opening value, the AER has modelled United Energy’s RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.20.

Table 18.20 AER forecast roll-forward of United Energy's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	1380.2	1518.4	1655.5	1757.7	1841.5
Net capital expenditure[a]	179.2	186.2	162.1	153.8	159.5
Indexation of opening RAB	35.5	39.1	42.6	45.3	47.4
Straight-line depreciation	–76.5	–88.2	–102.5	–115.3	–125.4
Closing RAB	1518.4	1655.5	1757.7	1841.5	1923.0

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that United Energy's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to United Energy's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.26.

The nominal vanilla WACC of 9.40 per cent is based on a pre-tax nominal return on debt of 8.81 per cent and a post-tax nominal return on equity of 10.28 per cent. These figures are calculated using United Energy's agreed averaging period of 20 business days ending 27 August 2010.

Depreciation

As discussed in chapter 10, the AER has not approved United Energy's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance.

Estimated taxes payable

Using the PTRM, the AER has modelled United Energy's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than United Energy's actual gearing, and a statutory company income tax rate of

30 per cent. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Table 18.21 shows the AER's estimate of United Energy's tax payments.

Table 18.21 AER modelling of United Energy's net tax allowance ($'m, nominal)

	2011	2012	2013	2014	2015
Tax payable	17.0	17.7	19.7	23.3	27.1
Value of imputation credits	–8.5	–8.8	–9.8	–11.7	–13.5
Net tax allowance	8.5	8.8	9.8	11.7	13.5

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for United Energy of $594.0 million (nominal) during the forthcoming regulatory control period, which is $94.0 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by United Energy under the ESCV's S factor and carryover mechanisms have been reduced to –$35.8 million (nominal) from the nil amounts proposed.

18.7 AER conclusion

In accordance with clause 6.12.1 (2) of the NER, the AER's decision on the annual revenue requirement for each Victorian DNSP is set out below. The AER's decision on the annual revenue requirement for each Victorian DNSP is also set out in the distribution determination documents for CitiPower, Powercor, JEN, SP AusNet and United Energy.

The AER has calculated each Victorian DNSP's revenue requirements and X factors based on its decisions regarding the aforementioned building block components. These calculations are summarised in the following sections.

CitiPower

The AER's final decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $1189.7 million, compared to $1350.8 million proposed by CitiPower. The main reasons for this difference reflect:

- a reduction of $112.7 million from the return on capital, reflecting a lower WACC and capex
- the removal of $39.1 million from the proposed opex allowance.

Table 18.22 AER conclusion on CitiPower's revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital	—	121.0	132.3	143.5	156.3	168.9
Regulatory depreciation	—	34.7	38.4	42.3	46.5	51.8
Operating expenditure	—	46.3	47.6	50.1	50.8	53.3
Efficiency carryover amounts	—	4.5	–8.4	–6.2	–5.5	0.0
S factor amounts	—	–2.2	–4.7	–3.6	–0.4	–4.0
Tax allowance	—	6.3	6.7	7.4	7.7	8.4
Annual revenue requirements	—	210.6	211.8	233.5	255.4	278.5
Expected revenues	213.3	205.8	221.0	235.3	252.8	273.9
Forecast CPI (per cent)	—	2.57	2.57	2.57	2.57	2.57
X factors (per cent)	—	6.41	–4.00	–4.00	–5.00	–5.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

CitiPower's building block revenue requirement for 2011 is slightly below its expected revenues for 2010, requiring an initial reduction in average prices. The AER has considered the subsequent increase in underlying revenue requirements when setting X factors, and has determined that moderate price increases from 2012 to 2015 are necessary to minimise the variance between the expected and required revenues in 2015. When taking into account the fact that revenue requirements in 2015 reflect –4.0 million (nominal) of amounts relating to S factor penalties, this difference is –3.03 per cent.

Powercor

The AER's final decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $2511.7 million, compared to $2878.9 million proposed by Powercor. The main reasons for this difference reflect:

- a reduction of $181.8 million to the return on capital, reflecting a lower WACC and capex
- the removal of $136.0 million from the proposed opex allowance
- –$56.9 million in carryover amounts, compared to the $25.3 million proposed

Table 18.23 AER conclusion on Powercor's revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital	—	208.0	227.7	247.1	267.2	288.8
Regulatory depreciation	—	62.1	69.9	77.9	86.3	96.8
Operating expenditure	—	160.9	167.8	169.9	179.3	188.2
Efficiency carryover amounts	—	0.0	1.2	–10.4	–14.5	0.0
S factor amounts	—	–6.1	–22.0	–5.6	–0.3	0.9
Tax allowance	—	12.5	12.9	14.1	15.0	16.4
Annual revenue requirements	—	437.4	457.4	492.9	532.9	591.1
Expected revenues	422.2	440.7	470.0	497.4	529.0	568.8
Forecast CPI (per cent)	—	2.57	2.57	2.57	2.57	2.57
X factors (per cent)	—	–0.11	–3.00	–3.00	–3.50	–4.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

The AER considers these X factors minimise the variance between the expected and required revenues in the final year to –3.78 per cent.

JEN

The AER's final decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $994.3 million, compared to $1106.1 million proposed by JEN. The main reasons for this difference reflect:

- the removal of $61.5 million from the proposed opex allowance
- a reduction of $55.7 million to the return on capital, reflecting a lower WACC and capex
- an offsetting increase of $15.7 million arising from higher than requested efficiency carryover amounts.

Table 18.24 AER conclusion on JEN's revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital	—	75.2	80.8	87.1	93.2	99.6
Regulatory depreciation	—	26.6	31.7	37.7	43.0	42.9
Operating expenditure	—	57.5	57.8	59.4	66.4	67.0
Efficiency carryover amounts	—	20.4	14.6	16.9	–0.7	0.0
S factor amounts	—	5.6	1.0	–0.2	–0.2	–11.1
Tax allowance	—	2.9	3.4	4.4	5.5	5.9
Annual revenue requirements	—	188.2	189.3	205.3	207.2	204.3
Expected revenues	168.8	179.8	190.1	199.3	209.1	220.8
Forecast CPI (per cent)	—	2.57	2.57	2.57	2.57	2.57
X factors (per cent)	—	–4.99	–3.00	–3.00	–3.00	–3.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

The AER considers these X factors minimise the variance between the expected and required revenues in the final year to 2.48 per cent when the –$11.1 million S factor penalty in 2015 is not taken into account.

SP AusNet

The AER's final decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $2446.5 million, compared to $2690.1 million proposed by SP AusNet. The main reasons for this difference reflect:

- the removal of $136.8 million from the proposed opex allowance
- a reduction of $107.8 million to the return on capital, reflecting a lower WACC and capex
- carryover amounts of –$57.2 million, compared to the –$38.5 million proposed, reflecting ECM and also S factor penalties.

Table 18.25 AER conclusion on SP AusNet’s revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital	—	200.2	219.9	244.6	270.0	295.7
Regulatory depreciation	—	91.1	51.2	62.3	58.1	55.1
Operating expenditure	—	162.9	174.2	184.9	199.2	207.1
Efficiency carryover amounts	—	11.4	–24.9	–9.3	2.0	0.0
S factor amounts	—	41.3	21.3	–7.6	–1.8	–89.6
Tax allowance	—	11.1	2.9	5.1	4.2	3.9
Annual revenue requirements	—	518.0	444.5	480.0	531.7	472.3
Expected revenues	373.9	430.0	458.4	488.4	528.1	575.0
Forecast CPI (per cent)	—	2.57	2.57	2.57	2.57	2.57
X factors (per cent)	—	–9.99	–4.00	–4.00	–5.00	–5.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM

SP AusNet's building block requirements are affected by significant S factor penalties and rewards over the period, from $41.3 million in 2011 to –$89.6 million in 2015 (nominal). The AER considers that it would not be appropriate to align expected revenues taking these amounts into account, as doing so is likely to create an unnecessary price shock in 2016 when the underlying building blocks are reassessed. In the absence of the S factor penalty, the difference between expected revenues and building block revenue requirements in 2015 is minimised at 2.34 per cent, compared to 21.75 per cent if the penalty is regarded.

United Energy

The AER’s final decision results in a total revenue requirement over the forthcoming regulatory control period of $1674.9 million, compared to $1944.1 million proposed by United Energy. The main reasons for this difference reflect:

- a reduction of $100.6 million to the return on capital, reflecting a lower WACC and capex
- the removal of $94.0 million from the proposed opex allowance
- S factor penalties–$35.8 million, compared to the nil amounts proposed.

Table 18.26 AER conclusion on United Energy's revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital	—	129.7	142.7	155.6	165.2	173.1
Regulatory depreciation	—	41.0	49.1	59.9	70.1	78.0
Operating expenditure	—	108.6	113.6	117.2	124.9	129.8
Efficiency carryover amounts	—	0.0	0.0	0.0	0.0	0.0
S factor amounts	—	–4.9	–5.1	–6.7	–6.8	–12.3
Tax allowance	—	8.5	8.8	9.8	11.7	13.5
Annual revenue requirements	—	282.9	309.2	335.8	365.0	382.1
Expected revenues	291.8	301.9	313.6	324.5	349.5	379.4
Forecast CPI (per cent)	—	2.57	2.57	2.57	2.57	2.57
X factors (per cent)	—	–0.37	–1.00	–2.00	–6.00	–6.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM

United Energy's building block requirements from 2011 are closely aligned to expected revenues in 2010. In subsequent years of the period, the AER has sought to apply steady price increases in order to align expected revenues and building block revenue requirements in 2015. The variance between the expected and required revenues in this year arising from this final decision is –0.70 per cent.

In accordance with clause 6.3.2(a) of the NER the AER has decided that the annual revenue requirements for each year of the regulatory control period for each Victorian DNSP are as follows:

Table 18.27 AER conclusion on the annual revenue requirements ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	210.6	211.8	233.5	255.4	278.5
Powercor	437.4	457.4	492.9	532.9	591.1
JEN	188.2	189.3	205.3	207.2	204.3
SP AusNet	518.0	444.5	480.0	531.7	472.3
United Energy	282.9	309.2	335.8	365.0	382.1

In accordance with clause 6.5.9 of the NER the AER has decided that the X factors for each year of the regulatory control period for each Victorian DNSP as follows:

Table 18.28 AER conclusion on X factors (per cent)

	2011	2012	2013	2014	2015
CitiPower	6.41	–4.00	–4.00	–5.00	–5.00
Powercor	–0.11	–3.00	–3.00	–3.50	–4.00
JEN	–4.99	–3.00	–3.00	–3.00	–3.00
SP AusNet	–9.99	–4.00	–4.00	–5.00	–5.00
United Energy	–0.37	–1.00	–2.00	–6.00	–6.00

19 Public lighting

Under clause 6.2.2 of the National Electricity Rules (NER), the AER may classify direct control services as either standard or alternative control services.

In its Framework and approach paper, the AER classified the Victorian DNSPs' provision of operation, maintenance, repair and replacement (OMR) of public lighting as an alternative control service.[1] Chapter 2 sets out the classification of services for the 2011–15 regulatory control period.

Clause 6.2.5 of the NER requires the AER, in its distribution determination, to impose controls (a control mechanism) over the prices of direct control services and/or the revenue to be derived from these services. Clause 6.2.5(d) of the NER outlines the factors the AER must have regard to in determining the type of control mechanism to apply to alternative control services. One option the AER may apply, and which it did apply, in respect of public lighting, is a cap on the prices of individual services.[2]

Clause 6.12.3(c) of the NER provides that the control mechanism to be applied in a distribution determination must be as set out in the AER's Framework and approach paper.

Clauses 6.12.1(12) and 6.12.1(13) of the NER require the AER to make constituent decisions on the control mechanism for alternative control services and how compliance with that control mechanism is to be demonstrated, respectively.

This chapter sets out the AER's final decision with respect to the public lighting OMR charges to be levied on customers during the 2011–15 regulatory control period. The chapter also determines the control mechanism to be applied to these charges.

19.1 History and overview of the Victorian public lighting charges model

In 2004, the ESCV created a financial model to test how the Victorian DNSPs' proposed public lighting OMR charges are derived. This followed concerns by local councils and VicRoads (the main customers of public lighting services in Victoria) that OMR charges were excessive and not fair and reasonable.[3]

The ESCV determined that public lighting was an excluded service and therefore regulated under ESCV *Guideline 14: Provision of Services by Electricity Distributors*.[4] The model was the result of extensive consultation between customers, the Victorian DNSPs and the ESCV.

The model used benchmark assumptions about the input costs of materials such as luminaires, photoelectric cells (PE cells), ballasts and the annual failure rates of those

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1 Clause 6.8.1 of the NER requires the AER to publish a framework and approach paper prior to every distribution determination. The paper must include details of the AER's control mechanism for each alternative control service.

2 See clause 6.2.5(d) of the NER.

3 Essential Services Commission of Victoria, *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004, p. 7.

4 ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004, p. iv.

components over their working life. These were added to labour costs in deriving OMR charges. This charge would ensure the Victorian DNSPs recovered opex spent on maintaining public lighting assets and replacing failed light components each year.

The model also recognised that, as the Victorian DNSPs incurred capex on luminaires, this capex would go into the public lighting regulatory asset base (RAB).[5] Such expenditure was recovered through a return of capital and depreciation according to the weighted average cost of capital (WACC) established by the ESCV. In this way, OMR charges would increase as the RAB increased. For example, actual capex was reported in the regulatory accounts with a two year time lag, therefore capex spent in 2006 would be recovered via an increase in OMR charges in 2008.

In summary, OMR charges were therefore derived from the Victorian DNSPs' public lighting opex and capex each year.

The model also incorporated an element of imprecision that cannot capture the individual operating characteristics of each Victorian DNSP. To accommodate this, the ESCV set benchmark unit rates in the model but would approve Victorian DNSPs' proposed OMR charges that were up to 10 per cent above the OMR charges derived from the model.

Therefore, the ESCV was approving the Victorian DNSPs' OMR charges, rather than 'approving' the Victorian DNSPs' respective input costs. The Victorian DNSPs could therefore adjust the input costs in the model, so long as their proposed OMR charges were no more than 10 per cent above charges predicted by the model.[6]

The AER adopted the ESCV's model in 2009, but amended some inputs to accommodate the entry of T5 energy efficient luminaires.[7] This included an OMR charge for T5s which was sought by councils seeking to reduce public lighting energy consumption (and therefore overall costs). Generally however, the model remained consistent with the 2004 version.

The AER updated the public lighting model in 2009 to enable the Victorian DNSPs to forecast public lighting opex and capex for the forthcoming regulatory control period. By incorporating these forecasts, OMR charges are generated for each year of the 2011–15 regulatory control period.

The model was also adjusted to ensure that during the 2011–15 regulatory control period, the Victorian DNSPs can recover capex on luminaires in 2009 and 2010 which has not yet been recovered from customers.[8] By permitting and smoothing the recovery of this capex over the five year period of 2011–15, customer price shock will be minimised.

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5 ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004, pp. 41–45.

6 ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004, pp. 23– 71.

7 AER, *Energy efficient Public Lighting Charges–Final Decision*, February 2009. This also included removing T5 ballast from an operating expenditure to a capital expenditure item.

8 Under the 2004 edition of the model, 2009 capex would have been recovered in 2011 OMR charges, while 2010 capex would have been recovered in 2012 OMR charges.

The model also reflects the ongoing costs faced by the Victorian DNSPs in dealing with intermittent failures and breakdowns of luminaires and other public lighting components as they occur. It therefore reflects the materials costs associated with spot replacement of various public lighting components. Importantly however, the model does not reflect the costs of materials based on a mass rollout of lighting technology.

Due to the AER's change of approach, the materials input costs proposed by the Victorian DNSPs now represent their actual or forecast costs. This takes into account each DNSP's particular circumstances, rather than the benchmark costs applied in the 2004 (and updated 2009) model.

In making its current assessment on input costs, the AER will allow for some potential differences between the services provided by each DNSP, and the input costs faced by each DNSP. Accordingly, the AER accepts that each DNSP may apply a different cost to the same input (for example, lamps).

The AER will accept the Victorian DNSPs' revised proposals where sufficient evidence is provided to the AER to justify input costs which have been adjusted from those established in the ESCV's 2004 decision and the AER's 2009 public lighting decisions.[9] The AER considers that this approach is consistent with the revenue and pricing principles (RPP) in s. 7A of the NEL and the National Electricity Objective (NEO) in s. 7 of the NEL.

Therefore, input costs for items, such as luminaires, lamps and ballasts, as well as failure rates for various components, are assessed by the AER on their merits. The ensuing approved input rates generate the OMR charges for each Victorian DNSP. In recognition of this, the 2009 model removed the 10 per cent buffer applicable to OMR charges under the 2004 model.

19.2 AER draft decision

The Victorian DNSPs' initial regulatory proposals included charges for existing luminaires and energy efficient luminaires, either recently installed on the network, or forecast to be installed during the 2011–15 regulatory control period.[10]

The AER reviewed the Victorian DNSPs' forecast opex and capex over the 2011–15 regulatory control period, together with the proposed input costs and volumes of luminaires, poles and brackets to be replaced, in assessing the efficient costs of providing public lighting services. The AER's draft decision set out these proposed charges (see tables 19.46 to 19.51 of the draft decision).[11]

In accordance with the 'propose-respond' model in the NEL and the NER, the draft decision considered the public lighting input costs of all Victorian DNSPs

9 ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004; AER, *Energy efficient Public Lighting Charges–Final Decision*, February 2009

10 Energy efficient luminaires refers to T5 (2x12W) and T5 (2x24W) lights. The Public Lighting Code defines a luminaire as all assets of the distributor which are dedicated to the provision of public lighting, including lamps, luminaires, mounting brackets and poles on which fixtures are mounted, supply cables and control equipment (for example, photoelectric cells and control circuitry) but not including the distributor's protection equipment (for example fuses and circuit breakers) By contrast, a light refers only to the lamp inside the luminaire housing.

11 AER, *Draft decision*, June 2010, pp. 824–829.

independently, such that the costs for a particular item, such as a PE cell, ballast or luminaire, may vary among the Victorian DNSPs. As noted above, where the Victorian DNSPs provided sufficient evidence that the input costs should be amended from those in the 2004 and 2009 decisions, the AER generally accepted those input costs.

This approach was consistent with the public lighting model developed by the AER which, as discussed above, was a refinement of the model first introduced in 2004 by the ESCV. The AER also reviewed the Victorian DNSPs' forecast opex and capex for the 2011–15 regulatory control period in light of actual public lighting opex and capex over previous regulatory periods.

The AER's draft decision rejected the Victorian DNSPs' proposed opex and capex inputs including the WACC, as well as the price smoothing mechanism proposed by some Victorian DNSPs. The AER also rejected the forecast capex replacement volumes of SP AusNet and United Energy.

The public lighting charges for the main light types approved by the AER were set out in chapter 19 of its draft decision and simplified for 2011 in table 19.1**.**

Table 19.1 AER draft decision OMR charges, main light types, 2011 ($, nominal)

Lighting service	CitiPower	Powercor	JEN	SP AusNet Central	SP AusNet North &East	United Energy
Mercury vapour 80 watt	65.31	40.26	37.60	34.88	38.55	48.88
Sodium high pressure 150 watt	99.74	72.01	73.40	72.96	82.18	78.26
Sodium high pressure 250 watt	101.39	74.59	74.77	73.87	81.57	79.57
T5 (2x14 watt)	34.49	27.33	24.37	30.11	32.93	25.15
T5 (2x24 watt)	–	–	–	34.55	37.46	–

Source: AER draft decision

19.3 Victorian DNSP revised regulatory proposals

The Victorian DNSPs submitted revised regulatory proposals which included revised public lighting models for the 2011–15 regulatory control period. These models included some revised opex and capex inputs and revised capex replacement volumes, which resulted in higher public lighting OMR charges than those approved in the AER's draft decision.

CitiPower and Powercor proposed amendments to the following inputs:

- application of a general materials escalator to materials other than poles and brackets
- costs of public lighting pole and brackets

- proportion of T5 (2x14W) lights that fail between bulk changes during 2011–15
- cost of patrol vehicles
- cost of T5 (2x14W) luminaires
- traffic management costs.[12]

JEN's revised regulatory proposal recommended amendments to:

- labour and materials cost escalation
- proportion of T5 (2x14W) lights that fail between bulk changes during 2011–15
- the WACC.[13]

SP AusNet's revised regulatory proposal disputed the AER's draft decision in relation to:

- the relevant regulatory requirements regarding the appropriate control mechanism for public lighting
- ownership of public lighting assets
- funding of MV80 replacement with T5 energy efficient lighting
- labour costs and escalation
- motor vehicle and plant (and elevated platform vehicle) costs
- other costs for SP AusNet's north and east regions
- proportion of T5 (2x14W) lights that fail between bulk changes during 2011–15
- forecast replacement volumes of luminaires, poles and brackets
- the introduction of new light types.[14]

United Energy accepted the AER's draft decision on public lighting charges, with the exception of opex and capex labour rates, including the labour rates for after hours work.[15] United Energy also contended that the AER should update United Energy's public lighting model to reflect the labour and materials cost escalators that the AER determines in the final decision.[16]

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12 CitiPower, *CitiPower Pty's Revised Regulatory Proposal 2011–15*, July 2010, pp. 451–454; Powercor, *Powercor Australia Ltd's Revised Regulatory Proposal 2011–15*, July 2010, pp. 452–455.

13 JEN, *Revised Regulatory Proposal*, July 2010, p. 318.

14 SP AusNet, *Revised Regulatory Proposal*, July 2010, pp. 393–404.

15 United Energy, *Revised Regulatory Proposal 2011–2015*—public lighting model, July 2010.

16 United Energy, *Revised Regulatory Proposal*, July 2010, p. 345.

The Victorian DNSPs' revised OMR charges for each light type are provided in appendix Q of this final decision.

19.4 Submissions

Submissions in response to the AER’s draft decision on public lighting were received from:

- Sylvania Lighting Australasia (Sylvania)
- Citelum Australia (Citelum)
- Streetlight Group of Councils (SGC)
- Darebin City Council (Darebin)
- Northern Alliance for Greenhouse Action (NAGA).

Sylvania expressed concern that the AER's draft decision did not include a regulated OMR charge for compact fluorescent lights (CFLs). Sylvania suggested that, if CFLs charges were not considered in the final decision, the AER should reassure councils that they could approach the AER with any concerns regarding a DNSP’s proposed CFL charges.[17]

Citelum suggested that the AER should consider existing ESCV policies, noting that the ESCV's 2004 draft decision indicated that many customers were misinformed about whether public lighting OMR services are contestable. Citelum also considered that there is still misinformation regarding the contestability of public lighting.[18]

SGC supports the AER's rejection in its draft decision of the Victorian DNSPs' proposed public lighting charges. This was made on the basis that the opex and capex inputs do not reflect the efficient costs of providing public lighting over the forthcoming regulatory control period. However, SGC raised concerns regarding the AER's draft decision, specifically in relation to:

- materials cost escalation
- traffic management costs
- 'other costs' for SP AusNet's north and east regions
- transitional capex adjustments
- forecast capex
- introduction of new lighting types

[17] Sylvania Lighting Australasia, *Comments – Draft decision Victorian electricity DNSPs distribution determination 2011–2015*, 10 June 2010, p. 2.

[18] Citelum Australia, *Submission to AER: Response to Draft Determination–public lighting contestability*, July 2010, p. 3.

- ownership and contestability of public lighting assets
- compliance with the price control mechanism.[19]

SGC also raised potential compliance issues from having OMR charges split between alternative control and negotiated distribution service classifications.[20]

Darebin considered that the AER's draft decision OMR charges for existing lights were too high and should be reconsidered.

However Darebin, along with NAGA and Citelum, agreed with the AER's position in the draft decision on the contestability of new public lighting assets.[21] NAGA also supported the draft decision's relatively lower OMR price increases for T5s compared to MV80 lights.[22]

19.5 Consultant review

19.5.1 Labour rates and on-costs

In its original report to the AER, Impaq Consulting (Impaq) determined that the competencies required for the repair and maintenance of public lighting are somewhat less than those for other line work, such as glove and barrier work.

The AER engaged Impaq to reconsider its original advice in light of issues raised in the Victorian DNSPs' revised regulatory proposals. Issues were raised in regard to the cost build up of labour rates applicable to other alternative control services. In particular, the AER asked Impaq to review issues raised in relation to the hourly labour charge out rates for line workers.

Impaq provided an addendum to its original report setting out the issues raised and its responses to those issues, which is available on the AER's website.[23] The following section outlines Impaq's advice on public lighting labour rates and the AER's consideration of that advice.

19.6 Issues and AER considerations—operating expenditure

19.6.1 Labour rates and escalation

19.6.1.1 AER draft decision

In reviewing the Victorian DNSPs' proposed labour rates, the AER considered the rates established in its 2009 final decision on energy efficient public lighting.[24] The AER was also persuaded by the recommended range for labour rates in Impaq's

19 SGC, *Submission to the AER–Victorian Distribution Draft Determination*, August 2010, p. 1.
20 SGC, *Submission to the AER–Victorian Distribution Draft Determination*, August 2010, p. 1.
21 Darebin, *Submission to the AER Draft decision*, August 2010, pp. 1–2; NAGA, *Submission to the AER Draft decision*, August 2010, p. 1; Citelum Australia, *Submission to AER*, July 2010, pp. 4–5.
22 NAGA, *Submission to the AER Draft decision*, August 2010, p. 1.
23 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010.
24 AER, *Energy Efficient Public Lighting Charges–Victoria (Final)*, February 2009, p. 40.

report, where Impaq made comparisons with the AER's previous determinations and the industry (NECA) benchmark rates.[25] Accordingly, the 2010 labour rates that the AER accepted in its draft decision for each Victorian DNSP were:

- $71.41 per hour for normal hours
- $82.12 per hour for after hours (night patrols).[26]

The AER’s labour escalators for standard control services were set out in appendix K of the draft decision. The AER applied these cost escalators, as set out in table 19.2, to the 2010 labour rates for each year of the forthcoming regulatory control period. This resulted in the labour rates for 2011–15 as set out in table 19.2.

Table 19.2 AER draft decision on real escalation for outsourced labour (per cent, per annum) and labour rates ($, 2010) for 2011–15

	2011	2012	2013	2014	2015
Labour escalation	0.87	1.48	1.89	1.87	0.69
Labour rate (normal hours)	72.03	73.09	74.47	75.86	76.39
Labour rate (after hours)	82.83	84.06	85.64	87.24	87.85

Source: AER analysis.

19.6.1.2 Victorian DNSP revised regulatory proposals

The AER notes that CitiPower and Powercor did not raise any issues regarding the public lighting labour rates published in the draft decision.

JEN accepted the AER's draft decision labour rates but proposed a set of revised labour escalators. These proposed escalators are provided in table 19.9 and assessed in section 19.6.1.4.

SP AusNet's revised regulatory proposal agreed with the general approach to reviewing the Victorian DNSPs' labour rates adopted by Impaq and supported by the AER. However, SP AusNet considered that Impaq's review contained several errors of fact, including:

- Impaq's view that the competencies required to repair, maintain and replace public lighting assets are limited to that of a distribution line worker, makes no provision for the diversity of skill sets that any group or team of line workers will have, or for the supervision of the crew
- Impaq's review failing to take account of the most recent Enterprise Bargaining Agreement (EBA) for line workers which reduced working hours per day from 8.33 to 8.00.[27]

[25] AER, *Draft decision*, June 2010, p. 802.
[26] AER, *Draft decision*, June 2010, p. 802.
[27] SP AusNet, *Revised regulatory proposal*, July 2010, p. 396.

SP AusNet contended that its labour rates were based on the actual rates provided by the primary contractor providing the resource for the public lighting repair and maintenance activities.[28]

SP AusNet also stated that the AER did not provide the Impaq report for the Victorian DNSPs to review and therefore, SP AusNet was unable to determine Impaq's reasoning. Further, SP AusNet noted that the rates in table 19.32 of the draft decision were similar to those in table 12 of Impaq's report titled *Review of Distributors Proposed Rates in ACS Charges, Revision 1.3*.[29]

SP AusNet contended that no explanation had been provided for the inconsistency between the review of labour rates for public lighting services and other alternative control services, with regards to costs and overheads.[30]

SP AusNet's revised regulatory proposal submitted that:

- the labour rates accepted for all other alternative control services are applicable to public lighting services, as there is no reason to differentiate them, and to do so is unreasonable.[31]
- the direct labour engaged in providing both service types is very similar, and that the skills required for public lighting crews are not limited to that of a basic distribution line worker.[32]
- the labour rates in table 19.3 should be applied for the forthcoming regulatory control period.

Table 19.3 SP AusNet's revised labour rates ($, 2010)

	2010	2011	2012	2013	2014	2015
Labour rate (per hour)	76.33	77.40	78.87	81.00	83.10	85.10
Labour rate for night patrols (per hour)	95.41	96.75	98.59	101.25	103.88	106.37

Source: SP AusNet, *Revised regulatory proposal 2011-15*, July 2010, p. 318.

For night patrols, SP AusNet adopted a 15 per cent loading to the normal hours rate as applied by the AER to the other Victorian DNSPs.[33]

United Energy's revised regulatory proposal accepted the AER's draft decision but included its own labour escalator of 2.6 per cent per annum, applicable to public lighting for the forthcoming regulatory control period.[34]

28 SP AusNet, *Revised regulatory proposal*, July 2010, p. 396.
29 SP AusNet, *Revised regulatory proposal*, July 2010, p. 396; AER, *Draft decision*, June 2010, p. 800.
30 SP AusNet, *Revised regulatory proposal*, July 2010, pp. 396–397.
31 SP AusNet, *Revised regulatory proposal*, July 2010, pp. 396–397.
32 SP AusNet, *Revised regulatory proposal*, July 2010, p. 397.
33 SP AusNet, *Revised regulatory proposal*, July 2010, p. 397.
34 United Energy, *Revised Regulatory Proposal*–public lighting model, July 2010.

19.6.1.3 Consultant's review

Impaq provided an addendum to its original report (addendum report) setting out the issues raised by the Victorian DNSPs and its responses to those issues in relation to charge out rates for lineworkers.

Impaq also considered the Victorian DNPSs' revised regulatory proposals regarding the number of public holidays and daily work hours in the Communications, Electrical and Plumbing Union (CEPU) work agreement.[35]

Based on this information, Impaq's addendum report reduced the hours available for public lighting by 4.9 per cent, from 1642.5 to 1562.4 hours.

Impaq's addendum report also provided the components of on-costs for normal time activities and after hours. These are provided in table 19.4.

Table 19.4 Impaq's revised on-costs (per cent)

Item	On Costs - Low Case	On Costs - High Case	Comment
Superannuation	9	10	The low case is the Superannuation guarantee value of 9 per cent. The high case at 10 per cent is derived from the CP/PAL CEPU workplace agreement
Long Service Leave	1.7	2.5	The low case is based on Long service leave of 13 weeks after 15 years service. The high case is based on 13 weeks Long service leave after 10 years of service
Workcover (estimate)	1	1	Low case and high case reflect information from DNSP's submissions
Payroll Tax	4.9	4.9	Victorian Payroll Tax Rate – Revised for post July 2010
Annual leave loading (17.5%)	1.3	1.3	Based on 17.5 per cent loading on 4 weeks annual leave
Total On costs	18	20	

Source: Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 7.

Impaq also noted that its previous report presumed that the overhead rate included allowance for non-chargeable activities such as:

- training
- work group meetings
- OHS meetings for representatives

[35] Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 6.

- union meetings
- jury service.[36]

Impaq stated that subsequent investigation had indicated that these activities may not have been included in all instances. Impaq responded to JEN's revised regulatory proposal by including an allowance for non-productive time of 10 per cent in the low case. Impaq also noted that:

> the AER's final determination on Public Lighting for Energy Australia in April 2010 has included non-productive time of 51 min per day which is 15%. The low case 10%, non productive time allowance (which gives 90% utilisation on chargeable work) represents an 11.1% adder to the effective charge out rate calculated. The high case 15% non productive time gives a 17.6% adder.[37]

In terms of overheads, Impaq noted that:

> Nothing has come to our attention that would indicate that the previously determined range for overhead rates from 20% to 31% is inappropriate.[38]

In relation to profit margins, Impaq noted that its original report stated that the applicable margin would typically be in the range of 3 per cent to 8 per cent. However, in its addendum report, Impaq noted that:

> various electrical contracting businesses have a significantly higher risk profile (and hence a higher EBIT margin should apply) due to the fact they must compete to win electrical contracting work, where as DNSPs have a monopoly on Alternative Control Services.[39]

Having regard to these issues, Impaq revised the total margin above direct labour cost, which is summarised in table 19.5.

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36 Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 7.

37 Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 7.

38 Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 8.

39 Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 8.

Table 19.5 Impaq's total margin above direct wages cost for business hours (per cent)

Item	Total Margin—Low Case	Total Margin—High Case
On costs	18	20
Non Productive time contribution (10 per cent non productive time trans)	11	18
Overheads	20	31
Profit Margin	3	8
Total [(a)]	62	99

(a) The total margin is not the arithmetic sum of the other items as they are compounding.

Source: Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 8.

In terms of after hours rates, Impaq considered it reasonable that almost all after hours alternative control services could be performed either on the basis of afternoon shift or overtime on day shift. Impaq also noted:

> It is understood the Citipower and Powercor EBA allows the normal time working day to be 7.2 hours between 6am and 6pm. With 2 hours of overtime that allows work up to 8pm. Afternoon shift can cover times to at least 10pm.[40]

Impaq also noted that CitiPower's and Powercor's EBA included a 15 per cent loading on afternoon shift, and hence the effective chargeout rate for afternoon shift is 15 per cent more than for normal business hours.[41]

Impaq's addendum report also provided the total margin above direct wages cost when overtime of two hours or less is worked, which is shown in table 19.6.

[40] Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 8.

[41] Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 9.

Table 19.6 Impaq's total margin above direct wages cost for overtime (per cent)

Item	Total Margin—Low Case	Total Margin—High Case
Overtime loading	50	50
On costs	15	16
Non Productive time contribution (10% non productive time trans	0	0
Overheads	10	15
Profit Margin	3	8
Total [(a)]	95	116

(a) The total margin is not the arithmetic sum of the other items as they are compounding.

Source: Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 9.

In respect of table 19.6 Impaq noted that:

- the on-costs for overtime are less as overtime does not accrue long service leave or annual leave loading
- non productive time should be zero on overtime as the overtime is worked specifically for a particular job and all time is chargeable
- overheads are also lower for overtime
- normal business hours overheads are expected to be recovered during business hours and hence there is much less overhead to be recovered from overtime (which is not planned working time).[42]

Impaq noted the net result of the above is that:

> the cost of out of hours work using overtime is little different to that for afternoon shift. Hence the charge-out rates for after hours services are based on an afternoon shift, and are determined by adding a 15% penalty rate for afternoon shift as required in the Award.[43]

Table 19.7 shows the resulting recommended range of charge out rates for business hours and after hours based on the analysis in Impaq's addendum report.

[42] Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 9.

[43] Electrical Power Industry Award – 2010, page 24 (in Impaq, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 9.).

Table 19.7 Impaq's charge out rate assessment ($ per hour)

Charge out rates	Low Case	High Case
Business Hours	58.04	89.30
After Hours	66.75	102.69

Source: Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges, August 2010*, pp. 9-10.

19.6.1.4 AER considerations

Labour rates

CitiPower, Powercor, JEN and United Energy all accepted the 2010 labour rates published in the AER's draft decision. This was the starting point for establishing the 2011 labour rates.

The AER accepts that SP AusNet's decision not to provide labour rate indexation in its original proposal was an oversight by SP AusNet, and should be reconsidered.

The AER also acknowledges that the information in table 19.32 of the AER's draft decision should be replaced with the information in table 12 of Impaq's report.[44]

The AER notes that SP AusNet agreed with Impaq's general approach to reviewing labour rates. Notwithstanding this, SP AusNet has commented that:

> …it is SP AusNet's view that any review of this nature should be taken by the AER as the basis of establishing a view on the fairness and reasonableness of the proposed amounts and not an absolute determination of the value to be allowed.[45]

The AER used Impaq's addendum report as the basis for determining the labour rates it would accept for the respective Victorian DNSPs, noting that each DNSP may have different direct labour and associated costs.

The AER had regard to the labour rates in its 2009 final decision, the labour rates proposed by the other Victorian DNSPs and Impaq's review of public lighting labour rates. Impaq's review was based on:

- calculation of a charge-out rate based on wage rates plus on-costs, overheads and a profit margin
- evidence from other jurisdictions, including:
  - rates published by ETSA Utilities, Country Energy and EnergyAustralia
  - rates included in the Victorian DNSPs' submissions to the AER's distribution determinations in other jurisdictions, including New South Wales and Queensland

44 Impaq Consulting, *Review of rates in proposed ACS Charges*, May 2010, p. 37.
45 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 395.

- the AER’s draft determination on EnergyAustralia's provision of public lighting services

- comparative benchmarked rates from the National Electrical and Communications Association (NECA).[46]

The AER also notes SP AusNet's comments that the AER's draft decision labour rates for other alternative control services should apply to public lighting services, with SP AusNet contending that:

> …the skill set required for the public lighting crew is not limited to that of a "basic distribution line worker".

In contrast to this however, the AER considered Impaq's conclusion that:

> From our analysis the competencies required for the repair and maintenance of public lighting are somewhat less than that for other line work (eg: glove and barrier).
>
> For the other categories of alternative control services involving line workers the average skill levels required are higher than for public lighting.

To inform its view on the labour required for public lighting works, the AER requested SP AusNet to provide evidence (that is, work contracts, EBA documents) to support its proposed labour rates. In response, SP AusNet stated that it:

> engages the services of a third party contract service provider to manage the maintenance of its Public Lighting system. This contract has been established through a competitive tendering process and the specific costs for Labour and Plant are not divulged in the contract documents…rates have been captured from SP AusNet’s job quoting system that is used in providing customers with competitive quotes for work using similar resources, unless noted to the contrary.[47]

SP AusNet also noted that its labour rate (for normal hours) of $75.38:

> has been taken from the SP AusNet estimating system for competitive construction works, therefore it represents a reasonable weighted average labour cost for this type of work using either day labour or contract labour.[48]

Similarly, the original labour rate (for after hours) of $86.69:

> was provided by the SP AusNet contractor that provides this service. The rate has been compared to the afterhours rate used in SP AusNet’s estimating system of $108.21 and is considered to be reasonable for an activity that can only be conducted overnight.[49]

The AER notes that SP AusNet's revised public lighting model adjusted its 2010 labour rates to $76.33 for normal hours and $95.41 for after hours works.[50]

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46 Impaq Consulting, *Review of rates in proposed ACS Charges*, May 2010, p. 3.
47 Email from SP AusNet to the AER, 8 February 2010, p. 7.
48 Email from SP AusNet to the AER, 8 February 2010, p. 7.
49 Email from SP AusNet to the AER, 8 February 2010, p. 7.
50 SP AusNet, Revised Regulatory Proposal–public lighting model, July 2010.

In assessing SP AusNet's proposed labour rates, the AER has had regard to Impaq's addendum report as a basis for establishing the AER's view on the reasonableness of the Victorian DNSPs' proposed labour rates. In particular, this assessment was based on the requirements of s. 7A(2) of the NEL.

The AER notes that the addendum report recommended labour charge out rates of between $58.04 and $89.30 during normal hours and $66.75 and $102.69 for after hours.[51] The AER has also adopted Impaq's recommendations when setting the labour rates applicable to other alternative control services (see chapter 20).

The AER notes that the proposed labour rates in SP AusNet's revised regulatory proposal are within the range of recommended labour rates set out in Impaq's addendum report.[52] Accordingly, the AER accepts SP AusNet's proposed 2010 labour rates of:

- $76.33 per hour for normal hours
- $95.41 per hour for after hours work.

The AER also notes that CitiPower's and Powercor's initial regulatory proposals included 2010 labour rates of:

- $78.12 per hour for normal hours
- $89.84 per hour for after hours work.[53]

As these rates fall within Impaq's recommended charge out rates accepted by the AER, the AER has adopted these 2010 labour rates for CitiPower's and Powercor's respective public lighting models for the final decision. This is regardless of the fact that both DNSPs—in their respective revised regulatory proposals—agreed with the AER's draft decision 2010 labour rates as provided in section 19.6.1.1.

The AER will maintain the labour rates established in its draft decision for JEN's and United Energy's respective public lighting models. These are consistent with the AER's 2009 decision, the recommended range provided by Impaq, and were not the subject of objection in JEN's and United Energy's revised regulatory proposals.[54]

The AER will apply the outsourced labour escalators set out in appendix K of this final decision to the 2010 labour rates accepted for each Victorian DNSP. This will determine the labour rates applicable to public lighting for 2011–15 as set out in tables 19.11 and 19.12.

[51] Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, p. 10.

[52] Impaq Consulting, *Addendum to Review of Distributors Proposed Rates in ACS Charges*, August 2010, pp. 9–10

[53] CitiPower, *Regulatory proposal–public lighting model*, November 2009; Powercor, *Regulatory proposal–public lighting model*, November 2009.

[54] AER, *Draft decision*, June 2010, p. 802.

Labour cost escalation

The labour cost escalators applied to public lighting in the AER's draft decision is reproduced in table 19.8.

Table 19.8 AER draft decision on annual real increase in labour rates (per cent)

	2011	**2012**	**2013**	**2014**	**2015**
All Victorian DNSPs	1.41	1.90	2.70	2.60	2.40

Source: AER, *Draft decision*–Victorian DNSP public lighting models June 2010.

In their revised regulatory proposals, JEN, SP AusNet and United Energy submitted annual increases for their labour costs set out in table 19.9. CitiPower and Powercor did not take issue with the draft decision labour rate escalation.

Table 19.9 Victorian DNSP revised annual real increase in labour rates (per cent)

	2011	**2012**	**2013**	**2014**	**2015**
JEN	1.79	2.21	2.35	2.09	1.89
SP AusNet	1.40	1.90	2.70	2.60	2.40
United Energy	2.60	2.60	2.60	2.60	2.60

Source: Victorian DNSPs, *Revised regulatory proposals*–public lighting models, July 2010.

The AER's reasoning and final decision on labour cost escalation applicable to standard and alternative control services (including for public lighting) is set out in appendix K.

The AER's final decision escalation rates for outsourced labour for each Victorian DNSP are provided in table 19.10.

Table 19.10 Final decision on real cost escalation for outsourced labour (per cent)

	2011	**2012**	**2013**	**2014**	**2015**
CitiPower	0.8	2.7	5.1	8.4	10.7
Powercor	0.8	2.7	5.1	8.4	10.7
JEN	0.8	2.7	5.1	8.4	10.7
SP AusNet	0.8	2.7	5.1	8.4	10.7
United Energy	0.8	2.7	5.1	8.4	10.7

Note: The figures in this table have been rounded to two decimal places
Source: AER analysis

The AER has applied these escalators to each Victorian DNSPs' respective 2010 labour rates for the forthcoming regulatory control period. This results in the labour rates for 2011–15 for each Victorian DNSP as shown in tables 19.11 and 19.12.[55]

19.6.1.5 AER conclusion

The AER's final decision on the Victorian DNSPs' public lighting labour rates for the forthcoming regulatory control period is provided in tables 19.11 and 19.12.

Table 19.11 Final decision on labour rates ($, 2010), normal hours

	2010	2011	2012	2013	2014	2015
CitiPower	78.12	78.76	80.21	82.11	84.68	86.45
Powercor	78.12	78.76	80.21	82.11	84.68	86.45
JEN	71.41	71.99	73.31	75.06	77.40	79.02
SP AusNet	76.33	76.96	78.37	80.23	82.74	84.47
United Energy	71.41	71.99	73.31	75.06	77.40	79.02

Source: AER analysis

Table 19.12 Final decision on labour rates ($, 2010), after hours

	2010	2011	2012	2013	2014	2015
CitiPower	89.84	90.57	92.24	94.43	97.38	99.42
Powercor	89.84	90.58	92.24	94.43	97.39	99.42
JEN	82.12	82.79	84.31	86.32	89.01	90.88
SP AusNet	95.41	96.19	97.96	100.29	103.42	105.59
United Energy	82.12	82.79	84.31	86.32	89.01	90.88

Source: AER analysis

19.6.2 Elevated platform vehicle and patrol vehicle costs

19.6.2.1 AER draft decision

The vehicle costs adopted by the AER in its draft decision were:

- $10.00 for patrol vehicles (per hour)[56]
- $35.00 for elevated platform vehicles (per hour) for urban MV80 and T5 lights
- $45.00 for elevated platform vehicles (per hour) for rural MV80, T5 and S-HP lights.[57]

[55] It should be noted that the escalators for each year, will be applied to the labour rates for the reference year 2010. That is, labour rates will not be escalated on a compounding basis.

[56] AER, *Draft decision*, June 2010, p. 802.

19.6.2.2 Victorian DNSP revised regulatory proposals

CitiPower's and Powercor's revised regulatory proposals submitted that the rate for patrol vehicles should be $25.43 per hour (an increase from their initial proposal of $25.00), as this was:

> …the average of the rates quoted in CitiPower's (and Powercor Australia's) internal document, which sets out the rates for contractors in the regional areas. As a reasonableness check based on the ATO 'rate per business kilometre' for an ordinary engine 1.601–2.6 litre (1,1601–2,600cc) of 74 cents per kilometre[58] multiplied by an approximated 40 kilometre per hour travelled by the patrol vehicle, the rate is $29.60 per hour.[59]

CitiPower and Powercor believed that the AER should accept their proposed rates because they are externally derived.[60]

SP AusNet's revised regulatory proposal noted that the AER had incorrectly referenced its 2009 final decision in stating that it would adopt the platform vehicle rates of $10.00. SP AusNet also considered that:

> The AER has not provided any basis, description or supporting evidence for rejecting SP AusNet's submitted charges except for the reference to the 2009 Final Decision which was made in error.[61]

In addition, SP AusNet considered that it was inappropriate to apply rates originally adopted in 2004 to the forthcoming regulatory control period.[62] SP AusNet further noted that its proposed rates were established by reference to rates charged by contractors for each of the above vehicle types for the 2010 financial year. SP AusNet therefore proposed that the appropriate rates are those it originally submitted:

- light elevated platform vehicle (urban use) rate of $40.00 per hour
- heavy elevated platform vehicle (rural and remote use) rate of $72.28 per hour
- platform vehicle (night patrols) rate of $27.40 per hour.[63]

19.6.2.3 AER considerations

In response to CitiPower's and Powercor's revised regulatory proposals, that patrol vehicles costs should be increased to $25.43 per hour, the AER noted the information sourced from the Australian Taxation Office (ATO) website. This included the rate per business kilometre for an ordinary engine of 74 cents per kilometre.[64]

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57 AER, *Draft decision*, June 2010, p. 814.

58 'ATO, *Tax Return Information on Work-related Car Expenses'* (in CitiPower, *Revised Regulatory Proposal*, July 2010, p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 454).

59 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 454.

60 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 454.

61 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 394.

62 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 394.

63 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 394.

64 'ATO, *Tax Return Information on Work-related Car Expenses'* (in CitiPower, *Revised Regulatory Proposal*, July 2010 p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 454.).

Further, the AER notes that in responding to the AER's request for evidence and documentation to support their proposed cost increase for patrol vehicles ($25.00 per hour), CitiPower and Powercor provided the following:

> - patrol vehicles (per hour) of $25.00 – This cost reflects the average patrol vehicle rates as determined by PNS's [CitiPower and Powercor's service provider] sub-contractor.[65]

The AER has considered the matters put forward by CitiPower and Powercor and agrees that amendments to the rates established in 2004 and 2009 is warranted, based on the subcontracting evidence provided above.[66]

Therefore, the AER accepts that CitiPower's and Powercor's patrol vehicle costs will be $25.43 per hour for the forthcoming regulatory control period, as proposed.

Regarding SP AusNet's comments in its revised regulatory proposal, the AER acknowledges that its draft decision should have referred to the 'patrol vehicle' rates of $10.00 established in the AER's 2009 final decision, and not the 'elevated platform vehicle' costs.[67]

However, the AER notes that in responding to the AER's request for evidence and documentation to support its proposed cost increase for patrol vehicles ($27.40 per hour), SP AusNet stated that it:

> … does not have access to the specific costs of vehicles used by its contractors, this rate is that used for a light vehicle in SP AusNet's estimating system for competitive construction works, therefore it represents a reasonable cost for this type of vehicle.[68]

Similarly, when justifying its proposed costs for elevated platform vehicles for urban areas ($40.00 per hour), SP AusNet stated:

> This vehicle rate was provided by the SP AusNet contractor that provides this service. The rate has been compared to the rate used in SP AusNet's estimating system of $72.78 for a large EPV and is considered to be reasonable for the use of a smaller EPV that can be used in urban areas.[69]

In support of its proposed costs for elevated platform vehicles for rural areas ($72.28 per hour), SP AusNet stated it:

> …does not have access to the specific costs of plant and equipment used by its contractors, this rate has been taken from SP AusNet's estimating system for competitive construction works, therefore it represents a reasonable cost for this type of plant.[70]

To inform its decision on each Victorian DNSP's input costs, it is important for the AER to be provided with evidence that enables it to provide a DNSP with a

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65 Email from CitiPower and Powercor to AER, 8 February 2010, p. 7.
66 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 454.
67 AER, *Energy Efficient Public Lighting Charges—Victoria (Final)*, February 2009, p. 40.
68 Email from SP AusNet to AER, 8 February, p. 7.
69 Email from SP AusNet to AER, 8 February, p. 7.
70 Email from SP AusNet to AER, 8 February, p. 7.

reasonable opportunity to recover at least the efficient costs it incurs in providing direct control services (clause 7A(2) of the NEL).

The AER concludes that, on the basis of the reasoning provided, SP AusNet has established that its proposed costs for elevated platform and patrol vehicles are in accordance with the NEO and the RPP.

The AER's final decision on SP AusNet's vehicle costs for public lighting services will be:

- light elevated platform vehicle (urban use) rate of $40.00 per hour
- heavy elevated platform vehicle (rural and remote use) rate of $72.28 per hour
- platform vehicle (night patrols) rate of $27.40 per hour.

19.6.2.4 AER conclusion

The AER's final decision on the Victorian DNSPs' vehicle rates for the forthcoming regulatory control period is provided in table 19.13.

Table 19.13 AER final decision on vehicle rates ($, 2010), per hour

	Patrol Vehicles	Elevated Platform Vehicles (urban)	Elevated Platform Vehicles (rural)
CitiPower	25.43	35.00	45.00
Powercor	25.43	35.00	45.00
JEN	10.00	35.00	45.00
SP AusNet	27.40	40.00	72.28
United Energy	10.00	35.00	45.00

Source: AER analysis

19.6.3 Materials costs and escalation

19.6.3.1 AER draft decision

Material costs

The AER's draft decision maintained materials costs as per its 2009 final decision, due to a lack of evidence from the Victorian DNSPs to the contrary. These material costs included:

- $158.55 for MV80 luminaires
- $4.57 for MV80 lamps
- $18.45 for MV80 PE cell
- $33.21 for S-HP250 lamps

- $13.50 for a T5 (2x14W) PE cell
- $193.00 for a T5 luminaire.[71]

Materials escalation

The AER's draft decision applied materials costs escalation to standard control services and, where appropriate, alternative control services.

The AER considered that steel is the predominant material used for public lighting poles and brackets and therefore was the only appropriate materials escalator to be applied to the Victorian DNSPs' public lighting models. Other materials—like lamps and PE cells—were considered to have no comparable material escalator that the AER considered appropriate to apply. The AER also noted that the ESCV's 2004 public lighting model did not include escalation for materials (or labour).[72]

The AER considered that the Victorian DNSPs' public lighting charges are also indexed by CPI, which in the long run reflects the general movement in input costs throughout the economy. This ensures that the Victorian DNSPs receive appropriate compensation in OMR charges for changes in the price of materials.[73]

Therefore the AER's draft decision did not apply cost escalation to public lighting materials, except for public lighting poles and brackets.[74]

19.6.3.2 Victorian DNSP revised regulatory proposals

Material costs

CitiPower and Powercor submitted that the AER adopt a unit cost of $241.00 for T5 (2x14W) luminaires in its final decision, based on a recent quote from Pierlite Australia Pty Ltd (Pierlite) for spot replacements. This was more representative of luminaire costs than a quote previously provided by MAV (which was based on a bulk purchase) and which the AER applied in its draft decision.[75]

SP AusNet rejected the S-HP250 lamp cost of $33.21 in the AER's draft decision and instead applied a cost of $38.00 in its revised proposal.[76]

Materials escalation

CitiPower and Powercor disagreed with the AER's draft decision not to apply a materials cost escalator for public lighting materials other than poles and brackets. They considered that the AER should apply the general materials escalator to lamps, photo-electric (PE) cells, luminaires and miscellaneous materials (both bulk lamp and repair).[77]

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71 AER, *Draft decision*—Victorian DNSP public lighting models, June 2010.
72 AER, *Draft decision*, June 2010, pp. 803–804.
73 AER, *Draft decision*, June 2010, pp. 803–804.
74 AER, *Draft decision*, June 2010, pp. 803–804.
75 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 453; Powercor, *Revised Regulatory Proposal*, July 2010, p. 454.
76 SP AusNet, *Revised Regulatory Proposal*–public lighting model, July 2010.
77 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 451; Powercor, *Revised Regulatory Proposal*, July 2010, p. 452.

Despite the AER determining that these inputs had no comparable escalator for it to apply, CitiPower and Powercor considered that this was not a proper basis for the AER to exclude escalation on these materials.[78]

JEN, in conjunction with other Victorian DNSPs, engaged SKM to update the real materials cost escalation rates which were applied in its initial regulatory proposal. This was done with consideration of the real cost escalators used by AER in its draft decision.[79]

JEN adopted a composite (weighted) escalator applicable to various asset classes and updated its escalators in its revised regulatory proposal based on its consultants' (BIS Shrapnel, Econtech and SKM) advice.[80]

Table 19.14 sets out JEN's revised steel escalators. JEN submitted that these escalators are consistent with clauses 6.5.7(c)(3) of the NER and represent forecasts that are a realistic expectation of price movements over the forthcoming regulatory control period.[81]

Table 19.14 JEN's revised annual real cost escalators for steel (per cent)

	2011	2012	2013	2014	2015
Revised steel escalators	12.60	–4.70	–0.40	–1.60	–1.40

Source: JEN, *Revised regulatory proposal*, July 2010, p. 318.

SP AusNet did not seek materials escalation in its revised regulatory proposal.

19.6.3.3 Submissions

SGC noted that clause 2.1(c) of the PLC states that distributors must 'use best endeavours to develop and implement plans to provide OMR in a way which minimises costs to public lighting customers'. SGC argued that the material costs in the AER's draft decision public lighting models were too high for MV80 lamps, luminaires and PE cells.[82]

SGC stated that these do not represent the fair costs that other DNSPs pay for the same component or readily available market prices. In support of this SGC observed that:

> the CF42 [compact fluorescent 42] and MV80 are basically the same luminaire so cost should not exceed $85.65 representing the ESCV Paper's $131.50 (CF42) less $45.85 (ballast)… Our claim for a lower MV80 luminaire charge is supported by United Energy's $111.62 for 2011.[83]

[78] CitiPower, *Revised Regulatory Proposal*, July 2010, p. 451; Powercor, *Revised Regulatory Proposal*, July 2010, p. 452.
[79] JEN, *Revised Regulatory Proposal*, July 2010, p. 191
[80] SKM, *Victorian Distribution Network Service Providers cost escalator updates: Final Report – JENJEN/ United Energy Asset Categories*, 8 July 2010 (in JEN, Revised Regulatory Proposal, July 2010, p. 191).
[81] JEN, *Revised Regulatory Proposal*, July 2010, p. 193.
[82] SGC, *Submission to the AER*, August 2010, p. 3.
[83] SGC, *Submission to the AER*, August 2010, p. 3.

SGC proposed that 'fair and reasonable' costs for these materials should not exceed:

- $1.98 for MV80 lamps
- $85.65 for MV80 luminaires
- $12.00 for PE cells.[84]

19.6.3.4 AER considerations

Materials costs

The AER has had regard to the NEO in s. 7 of the NEL and, in particular, the RPP in s. 7A of the NEL in assessing public lighting inputs.

In response to SGC's concerns regarding the public lighting component costs, the AER notes that SGC did not provide any evidence (for example, quotations from vendors) to support their argument that:

> we identified a number of high charges included by distributors in their proposals for review by the AER…
>
> …to enable the AER to assess appropriate costs, we have sourced prices for common components based on very modest order amounts and must therefore be considered as the upper bounds of a fair cost as distributors will be purchasing in far greater quantities.[85]

The AER's draft decision on component costs for public lighting was based largely on those adopted by the ESCV's 2004 review of public lighting as well as the AER's 2009 final decision on energy efficient lights. Those decisions were made having regard to existing public lighting arrangements under the ESCV Public Lighting Code (PLC) and stakeholder submissions, including that of the Victorian DNSPs. The AER also observes that the Victorian DNSPs have, in some cases, maintained the input costs from the ESCV's 2004 decision.

In the absence of independent quotes or other documentation to suggest that the AER should depart from 2009 costs, the AER considers that those costs represent the efficient costs of providing public lighting services. Where supporting evidence has been provided, the AER has amended the input costs.

The AER maintains that the draft decision costs were largely adopted from the ESCV's 2004 public lighting model and the AER's 2009 final decision on energy efficient lights. Accordingly, the AER is not persuaded by SGC's submission, which has relied on anecdotal evidence of 'industry sources' that MV80 luminaires, MV80 lamps and PE cell costs should be lower than those adopted in the draft decision.

As no firm quotes were provided, the AER does not consider it appropriate to give weight to these arguments that component costs are below those costs established by the ESCV's 2004 public lighting decision and the AER's 2009 final decision.

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84 SGC, *Submission to the AER*, August 2010, p. 3.
85 SGC, *Submission to the AER*, August 2010, p. 17.

However, the AER has given consideration to the quotations provided to CitiPower and Powercor by Pierlite. For a quantity of 500 T5 (2x14W) luminaire units, the quotation provided:

- a price of $241.18 for each T5 (2x14W) luminaire including the PE cell
- a price of $223.65 for each T5 (2x14W) luminaire without a fitted PE cell.[86]

For the luminaire to work effectively, it requires a PE cell. Therefore, the AER has accepted CitiPower's and Powercor's quote of $241.18 for a T5 (2x14W) luminaire including PE cell as applicable to their network. The quote, which was based on a quantity of 500 luminaires, is deemed appropriate given CitiPower's and Powercor's forecast luminaire spot replacement volumes over the 2011–15 regulatory control period.[87]

The T5 (2x14W) luminaire costs (including PE cell) for JEN, SP AusNet and United Energy will remain at $193.00, as these DNSPs accepted the AER's draft decision on luminaire costs for their networks and did not propose revisions.

SP AusNet also advised the AER that the S-HP250 lamp cost of $33.21 is the appropriate input costs to apply, rather than a cost of $38.00 as provided in its revised public lighting model.[88] The AER has accepted this adjustment.

Materials cost escalation

The materials escalators applicable to all Victorian DNSPs are set out in appendix K, which includes the reasons as to why the AER adopted those escalators.

Consistent with appendix K, the AER's final decision is to apply the steel escalators to the unit costs of public lighting poles and brackets,[89] weighted by 45 per cent to reflect only the purchase price for steel. Table 19.15 shows the AER's final decision escalators.

[86] CitiPower and Powercor, Quotation from Pierlite for the cost of luminaires, 24 June 2010, p. 2 (in CitiPower, *Revised Regulatory Proposal*–Attachment 233, July 2010.).

[87] CitiPower, *Revised Regulatory Proposal*–public lighting model, July 2010; Powercor, *Revised Regulatory Proposal*–public lighting model, July 2010.

[88] Email from SP AusNet to AER staff on 23 September 2010.

[89] Including non-standard poles and brackets.

Table 19.15 AER final decision on real escalation rates for public lighting materials—poles and brackets (per cent)

	2011	2012	2013	2014	2015
CitiPower	9.4	8.4	7.3	6.3	5.5
Powercor	9.4	8.4	7.3	6.3	5.5
JEN	9.4	8.4	7.3	6.3	5.5
SP AusNet	9.4	8.4	7.3	6.3	5.5
United Energy	9.4	8.4	7.3	6.3	5.5

Note: The figures in this table have been rounded to two decimal places
Source: AER analysis

These escalation rates are to be applied to each Victorian DNSPs' 2010 costs of poles and brackets for each year of the forthcoming regulatory control period. The AER's consideration and final decision on the Victorian DNSPs' costs of public lighting poles and brackets are provided in section 19.7.2.

When reviewing the Victorian DNSPs' proposed materials escalators for public lighting services, the AER took into consideration its approach to materials escalation for standard control and other alternative control services in this final decision. The AER considers it appropriate to have regard to these services in order to establish a consistent approach for determining the applicable escalation rate to be applied to public lighting materials.

The AER also considers it appropriate, for reasons of consistency, to have regard to the treatment of materials escalation in other NEM jurisdictions. In this regard, the AER notes it has applied materials costs escalators to public lighting opex inputs for Ergon and Energex in the Queensland final decision.[90] Therefore, the AER considers it appropriate to apply a general materials escalator to opex materials in Victoria.

Accordingly, the AER has reconsidered its approach to material escalation for public lighting. The AER agrees with CitiPower and Powercor that it would be inappropriate to apply escalation to poles and brackets but not to other public lighting materials components.

The AER considers that it is appropriate to apply the general weighted opex escalation rates from appendix K of this final decision to the Victorian DNSPs' public lighting materials. These components include:

- lamps
- PE cells
- luminaires
- miscellaneous materials (for bulk lamp, and repair).

90 AER, Queensland distribution determination 2010–11 to 2014–15 (final), pp. 335–346

Table 19.16 sets out the final decision on materials cost escalations for these opex components over the forthcoming regulatory control period. These escalation rates are to be applied to the 2010 costs of the above opex components for each Victorian DNSP for each year of the forthcoming regulatory control period.

Table 19.16 AER final decision on real escalation rates for public lighting materials—other public lighting components (per cent)

	2011	2012	2013	2014	2015
CitiPower	0.6	2.1	3.9	6.2	7.4
Powercor	0.6	2.1	3.9	6.2	7.4
JEN	0.6	2.1	3.9	6.2	7.4
SP AusNet	0.6	2.1	3.9	6.2	7.4
United Energy	0.6	2.1	3.9	6.2	7.4

Note: The figures in this table have been rounded to two decimal places
Source: AER analysis

Appendix K sets out the AER's assessment and determination as to why these escalators were chosen.

19.6.4 Traffic management costs

19.6.4.1 AER draft decision

The AER's draft decision did not amend the traffic management costs originally proposed by SP AusNet, JEN and United Energy. However, the AER adopted SP AusNet's traffic management costs for Powercor's network, noting that their respective networks were similar as they are both predominantly rural.[91]

The AER also estimated that CitiPower's forecast costs were likely to be approximately four times that of JEN. The AER therefore apportioned the total costs by the major light types and the location of these lights based on the methodology used by JEN in apportioning its costs.[92]

The AER's draft decision on traffic management costs is set out in the table 19.17.

[91] AER, *Draft decision*, June 2010, p. 805–806.
[92] AER, *Draft decision*, June 2010, p. 805–806.

Table 19.17 AER draft decision on total traffic management costs ($, 2010)

	2011	2012	2013	2014	2015
CitiPower	102 041	103 029	104 033	105 021	106 027
Powercor	66 989	68 499	71 787	72 529	73 283
JEN	90 000	90 000	90 000	90 000	90 000
SP AusNet	47 214	55 916	64 955	66 234	67 534
United Energy	69 477	71 283	73 136	75 038	76 989

(a) Figure for T5 (2x14W) also includes proposed traffic management costs for T5 (2x24W) lights.

Source: AER, *Draft decision*, June 2010, p. 806.

19.6.4.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor revised their proposed traffic management costs to $13.75 per light and $8.56 per light, respectively. Both submitted that the AER should accept these because the costs were derived from a public tender. [93]

The other Victorian DNSPs did not contest the AER's draft decision. However, JEN submitted that:

> In 2004, traffic control costs could not be forecast by JEN or by the ESCV because the traffic control requirements had not been established at that time. The ESCV's public lighting model was not in a position to allow for the costs that were driven by the Road Management Act 2004. This is because the Road Management (Works & Infrastructure) regulations under the Road Management Act 2004 did not come into force until 2005. Further, the code of practice for management of infrastructure road reserves was only implemented in 2008.[94]

19.6.4.3 Submissions

SGC supported the AER's view that the Victorian DNSPs' proposed traffic management costs may not be reflective of efficient costs for providing those services. However, SGC also considered that:

> the hours allocated for services in the 2004 ESC model included allowances for traffic management services and that a separate component charge is therefore not valid and can be excluded by the AER.[95]

SGC stated that it was not aware of any material changes to the *Traffic Management Act* since the ESCV's 2004 review of public lighting established the input costs for the provision of lighting services by the Victorian DNSPs. SGC reiterated the views in its original submission which stated:

93 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 453; Powercor, *Revised Regulatory Proposal*, July 2010, p. 454.

94 Road Management Act 2004, Code of Practice: for Management of Infrastructure in Road Reserves, 6 October 2008 (in Jemena, *JEN 2011–15 regulatory proposal: response to stakeholder submissions,* September 2010, Attachment 1 - page 2.).

95 SGC, *Submission to the AER*, August 2010, p. 10.

> there has not been any change in the requirement of the Road Management Act which was introduced in January 2005 ie prior to the last regulatory period, with its requirements well know (sic) at the time of the ESCV's 2004 model which did not require a separate allowances for "traffic control charges", that is, it was included in the modelling.[96]

SGC also suggested that the traffic management costs for T5 lights should be reclassified by the AER as capital costs.[97]

19.6.4.4 AER considerations

In responding to SGC's concerns, the AER considers that the Victorian DNSPs incur traffic management costs in complying with the requirements of the Victorian *Road Management Act* 2004 (RMA). At the time of the 2004 decision, traffic management costs were not considered or included in the calculation of OMR charges. That was because the RMA had not taken effect and costs could not be estimated with certainty. Therefore, the AER concurs with JEN's statements above.

The AER disagrees with SGC's claims that traffic control costs were included in the 2004 model. Furthermore, these costs are more appropriately defined as opex, not capex as proposed by SGC, because they are incurred by a DNSP at the time of repairing or replacing damaged public lights. These are therefore common fixed costs borne by the Victorian DNSPs.

Therefore, as outlined in the draft decision, the AER considers that traffic management and control costs have become more significant since 2004.

In the draft decision, the AER noted that CitiPower and Powercor did not adequately explain their forecast traffic management costs and it was unclear whether these forecasts reflect reasonable assumptions and forecasting methodologies.[98]

In their respective revised proposals however, both CitiPower and Powercor proposed higher traffic management costs than those outlined in the AER's draft decision. Both parties stated that traffic management costs were 'competitively tendered', which resulted in 'efficient costs'.[99]

Taking this reasoning into consideration, the AER rejects CitiPower's and Powercor's revised traffic management costs, based on a benchmark analysis of the comparative costs proposed by other Victorian DNSPs. CitiPower and Powercor did not provide, in their revised regulatory proposals, any substantive evidence or documentation to justify their proposed costs, which are significantly higher than those of the other Victorian DNSPs.

Apart from this lack of evidence not supporting the NEO (it is unclear on the evidence available whether CitiPower's and Powercor's traffic management costs constitute efficient investment in or efficient operation and use of electricity services for the long term interests of consumers), the AER also considers that the RPP are not satisfied (see s. 7A(2) of the NEL).

96 SGC, *Submission to the AER*, February 2010, p. 13.
97 SGC, *Submission to the AER*, February 2010, p. 10.
98 AER, *Draft decision*, June 2010, p. 805.
99 CitiPower, *Revised regulatory proposal*, p. 453; Powercor, *Revised regulatory proposal*, p. 454.

Accordingly, the AER maintains its draft decision on CitiPower's and Powercor's traffic management costs.

The AER's final decision on traffic management costs for each Victorian DNSP for the 2011–15 regulatory control period is set out in table 19.18.

Table 19.18 AER final decision on Victorian DNSPs' traffic management costs, 2011–15 ($, 2010)

	2011	2012	2013	2014	2015
CitiPower	102 041	103 029	104 033	105 021	106 027
Powercor	66 989	68 499	71 787	72 529	73 283
JEN	90 000	90 000	90 000	90 000	90 000
SP AusNet	47 214	55 916	64 955	66 234	67 534
United Energy	69 477	71 283	73 136	75 038	76 989

Source: AER analysis.

19.6.5 Failure rates of T5 lights between bulk changes

19.6.5.1 AER draft decision

The draft decision contended that the Victorian DNSPs provided insufficient information to demonstrate that failure rates for T5 lights should be higher than the rate of 11.2 per cent, as established in the AER’s 2009 final decision. However, the AER recognised that further information on the performance and failure rates of energy efficient luminaires and components may come to hand over time.

Table 19.19 sets out the draft decision failure rates for MV80s and T5 luminaires.

Table 19.19 AER draft decision on percentage failure rates of lights between bulk changes, 2011–15 (per cent)

	MV80	T5 (2x14W)
CitiPower	15.0	11.2
Powercor	15.0	11.2
JEN	19.6	11.2
SP AusNet	15.0	11.2[a]
United Energy	19.6	11.2

(a) Figure for T5 (2x14W) also includes proposed traffic management costs for T5 (2x24W) lights

Source: AER analysis.

19.6.5.2 Victorian DNSP revised regulatory proposals

CitiPower's and Powercor's revised regulatory proposals observed that the AER had approved failures rates of 19.5 per cent and 18.5 per cent for T5 (2x14W) in their public lighting OMR charges 2010.[100] They submitted that the AER should therefore approve the same failure rates for the 2011–15 regulatory control period.[101]

JEN believed that the AER's draft decision incorrectly noted that each Victorian DNSP, except for United Energy, had proposed annual failure rates for MV80s which were unchanged from the proposed failure rates for 2010.

JEN commented that it had also proposed annual failure rates (19.6 per cent over a 4-year period) for MV80 lights which were different to those currently applying to it for 2010. JEN noted that these rates had been accepted by the AER.[102]

JEN contended that the AER's 2009 final decision on luminaire failure rates is significantly below the predicted failure rate and maintenance factor noted in the Victorian Sustainable Public Lighting Action Group (VSPLAG) report.[103] JEN's reasons for this are:

> Firstly, the lamp failure is not the only type of component failure that occurs in a T5 light. A T5 light uses the same type of photoelectric cell that is used in the existing MV80 lights and these photoelectric cells are susceptible to failure.
>
> Secondly, JEN is not aware of any evidence that suggests that the T5 lamp has a longer life than the MV80 lamp. Because there are two lamps in a T5 light, JEN considers there is a greater chance of a T5 light failure compared to a MV80 (which has only one lamp). By including the photoelectric cell failure rate with the T5 lamp failure rate, JEN believes that the T5 light failure rate will be the same, if not greater, than the MV80 lights.[104]

JEN believed that these propositions are supported by the VSPLAG report which states:

> T5, CF & 50w HPS low-energy lights have maintenance factors that exceed that of the 80W MV light.[105]

JEN also noted the VSPLAG report's general findings which stated that the T5 lights are:

> …the T5 (twin 14W & twin 24W) & the compact fluorescent (CF) (32W & 42W) low-energy lights were comparable or better in performance than the current standard, the 80W MV.[106]

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100 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 453.
101 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 453.
102 JEN, *Revised Regulatory Proposal*, July 2010, p. 319.
103 VSPLAG, *Evaluation of Low Energy Light for Minor Road Lighting*, 12 March 2008, pp. 8–9 (cited in JEN, *Revised Regulatory Proposal*, July 2010, p. 319).
104 JEN, *Revised Regulatory Proposal*, July 2010, p. 320.
105 VSPLAG, *Evaluation of Low Energy Light for Minor Road Lighting*, 12 March 2008, pp. 6–7 (in JEN, *Revised Regulatory Proposal*, July 2010, p. 320).

JEN considered that it is important not to misinterpret these 'general findings' and that the above is an 'overall evaluation'.[107] JEN also noted that VSPLAG's advice was not simply based on failure rates alone but includes other assessment criteria such as energy efficiency, light output depreciation over time and colour rendition.[108]

JEN recommended that T5 failure rates be aligned with its proposed rates for MV80s of 19.6 per cent. Street lighting services would otherwise be skewed towards the uptake of T5 lights and are not cost reflective given the VSPLAG assessment.[109]

SP AusNet noted that more than 80 per cent of its lights are MV80s, and that therefore, the failure rates in its revised regulatory proposal are indicative of annual MV80 failure rates.[110] SP AusNet also contended that those manufacturers' claims about failures do not account for:

> failures that are not lamp related, such as PE Cells, the luminaire, wiring and in addition to these accidents and vandalism. A recent sample of data indicated that about 60% of light failures attended involved the failure of the lamp and 40% all other reasons.[111]

SP AusNet submitted that its internal data on luminaire component failures provide a fairer representation of in-service failure rates. It contended that as these other factors are unlikely to vary greatly from light type to light type, it was proposed that:

> As a minimum the T5 failure rate be adjusted to include allowance for the 40% failures that are not lamp related, this raises the failure rate to 18.7%.[112]

19.6.5.3 Submissions

SGC proposed a reduction to the failure rates proposed by JEN and United Energy, stating that:

> both are well above those achieved through good asset maintenance practices. If JEN and UED are experiencing these rates we expect that they are either 1) using inferior (substandard) components or 2) not conducting the bulk lamp changes within the prescribed 4 years period.[113]

SGC also proposed that a maximum failure rate of 15 per cent (applicable to MV80 lights) should be applied to all luminaire types.

SGC submitted that if CitiPower and Powercor have higher failure rates, this would be due to bulk changes not being performed within the four year period. SGC proposed that the actual bulk changes should be audited by the AER to ensure a four year maximum. SGC also proposed that the AER investigate the 15 per cent failure

[106] VSPLAG, *Evaluation of Low Energy Light for Minor Road Lighting*, 12 March 2008, p. 3 (in JEN, *Revised Regulatory Proposal*, July 2010, p. 320).
[107] JEN, *Revised Regulatory Proposal*, July 2010, p. 320
[108] JEN, *Revised Regulatory Proposal*, July 2010, p. 320
[109] JEN, *Revised Regulatory Proposal*, July 2010, p. 320
[110] SP AusNet, *Revised Regulatory Proposal*, July 2010, Table 17.3, p. 399.
[111] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 399.
[112] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 399.
[113] SGC, *Submission to the AER*, August 2010, p. 12.

rate and consider the PE failure component, and adopt the same failure rate for PE cells for T5s and MV80s.[114]

19.6.5.4 AER considerations

In response to CitiPower's and Powercor's submissions, the AER notes that both DNSPs have misunderstood the AER's approval of its 2010 public lighting OMR charges with respect to T5 (2x14W) failure rates.

The 2004 version of the public lighting model relied on benchmark costs, as discussed in section 19.2 of this chapter. To accommodate likely differences among the Victorian DNSPs, approved OMR charges could be up to 10 per cent above the charges determined by the model. The AER (and previously the ESCV) therefore approved OMR charges, rather than specific inputs.

When proposing 2010 OMR charges for approval, CitiPower and Powercor did not apply the 10 per cent buffer. Instead, they adjusted the failure rates to deliver an outcome commensurate with applying the buffer. As this was consistent with the model, the AER approved their OMR charges.

By contrast, the 2011–15 public lighting model relies on the AER approving the Victorian DNSPs' actual, as opposed to benchmark, input costs and also assessing the forecast opex and capex within the model. In combination, these determine OMR charges.

Accordingly, the AER rejects CitiPower's and Powercor's respective failure rates of 19.5 per cent and 18.5 per cent.

The AER also considers that JEN may have misunderstood the AER's draft decision comment which noted:

> Each Victorian DNSP, except for United Energy, proposed annual failure rates for MV80s which are unchanged from the proposed failure rates for 2010.[115]

Although JEN claims that this was incorrect, the AER notes that each DNSP's (except United Energy's) public lighting model proposed MV80 failure rates which were consistent from 2010 to 2015. This included JEN's resubmitted model, which proposed an MV80 failure rate of 19.6 per cent for 2010 to 2015.[116] Accordingly, the AER does not accept JEN's suggestion that its comment was incorrect. Further, the AER does not accept JEN's statement that the AER 'proposed a failure rate of 19.6 per cent over a 4-year period', as this was in fact over a six year period.[117]

JEN's revised regulatory proposal provided some general information regarding the VSPLAG report. Notwithstanding this, the AER considers that JEN has not provided sufficient statistical evidence for the AER to depart from its draft decision which determined that T5 failure rates should be 11.2 per cent for all Victorian DNSPs.

114 SGC, *Submission to the AER*, August 2010, p. 12.
115 AER, *Draft decision*, June 2010, p. 809
116 JEN, *Regulatory proposal*–public lighting model, February 2010.
117 JEN, *Revised Regulatory Proposal*, July 2010, p. 319.

The AER notes that JEN used the 2008 VSPLAG report. However, the AER has decided to adopt the failure rates of 11.4 per cent for T5 luminaires as set out in the 2009 edition of the VSPLAG report.[118]

In the AER's draft decision it stated that:

> the AER considers that the information provided to it by the Victorian DNSPs was insufficient for it to determine that failure rates for T5 lights should be higher than the rate of 11.2 per cent, as established in the AER's 2009 final decision. It is recognised that further information on the performance and failure rates of energy efficient luminaires and components may come to hand over time.
>
> However, in the absence of sufficient information, the AER will continue to adopt 11.2 per cent as the proportion of T5 lights that fail between bulk changes.

The information provided in the Victorian DNSPs' revised regulatory proposals and SGC's submission, are insufficient for the AER to determine that T5 failure rates should differ from that of the 2009 VSPLAG report, being 11.4 per cent.

The AER also acknowledges the data provided by SP AusNet in its revised regulatory proposal.[119] This data show that the annual failure rate of the lights in its network, which are predominantly MV80 lights, is 10.67 per cent (rounded to 10.7 per cent) on average over the period 2004 to 2009. The AER also considers that, as more than 80 per cent of SP AusNet's light population are MV80s, this rate of 10.7 per cent is indicative of the failure rate for MV80 light types but not necessarily for T5 lights.

According to SP AusNet, the statistics:

> Relate to all failure types and therefore provide a fairer representation of the in service failure rates.[120]

The AER does not consider SP AusNet's request for a failure rate of 18.7 per cent follows from these statistics. Accordingly, the AER's final decision on the annual failure rates of MV80 and T5 lights for SP AusNet and the other Victorian DNSPs are as set out in table 19.20.

[118] VSPLAG, *Evaluation of Low Energy Light for Minor Road Lighting*, 12 March 2008, pp. 8–9.
[119] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 399.
[120] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 399.

Table 19.20 AER final decision percentage failure rates of lights between bulk changes, 2011–15 (per cent)

	MV80	T5 (2x14W)
CitiPower	15.0	11.4
Powercor	15.0	11.4
JEN	19.6	11.4
SP AusNet	10.7	11.4[a]
United Energy	19.6	11.4

(a) Figure for T5 (2x14W) also includes proposed traffic management costs for T5 (2x24W) lights

Source: AER analysis.

19.6.5.5 AER conclusion

The AER's final decision on luminaire failure rates between bulk changes is set out in table 19.20.

19.6.6 Other costs

19.6.6.1 AER draft decision

Geographical Information System (GIS) costs of $100 000 per annum for each Victorian DNSP were approved by the AER for the 2011–15 regulatory control period.[121]

SP AusNet's 'other costs' for the north and east regions were rejected because it had not provided sufficient evidence to substantiate those costs.[122]

19.6.6.2 Victorian DNSP revised regulatory proposals

SP AusNet did not agree with the AER’s draft decision to reject its proposed 'Other Costs for North and East Regions' and contended that the AER:

- incorrectly stated that SP AusNet receives a 5 per cent premium in costs for rural areas
- was wrong to claim that SP AusNet did not explain what these additional costs were for.[123]

SP AusNet's revised regulatory proposal explained that:

> the 5% premium that is applied to Rural and remote lights is applied to material costs to cover the additional transport and handling costs for materials delivered to sites in these areas. The premium is only applied to materials and does not cover any of the other costs associated with servicing lights in these areas.

121 AER, *Draft decision*, June 2010, p. 807.
122 AER, *Draft decision*, June 2010, p. 808.
123 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 398.

Further, SP AusNet noted that:

> the additional costs claimed cover requirements of a Living away from home allowance. SP AusNet is obliged to pay crews working on public lighting in rural and remote areas an allowance to cover the costs of accommodation and meals when they are required to stay overnight in an area rather than return to the depot and then back to the same or similar location the following day.[124]

SP AusNet claimed that these costs were expected to be incurred to efficiently provide public lighting services, rather than being an SP AusNet cost. SP AusNet reported this cost as:

> $120 per crew member paid out on 75 events in each region a year and allocated between MV80 lanterns and T5 lanterns on the basis of the number that each light type represents in the North and East areas.[125]

SP AusNet proposed a unit cost of $1.25 to be included in the cost of 'bulk change and repairs' for its MV80 and T5 lights in the north and east regions of it network.[126]

19.6.6.3 Submissions

SGC did not support the AER's draft decision on the annual GIS allowance of $100 000. SGC explained that:

> The GIS services were originally included to enable distributors to establish their spatial location of the assets and to provide web based access to public lighting customers over the prior period. This has now been completed by all distributors.[127]

SGC proposed that the spatial location, type and customer and web-based access is now already established, and that the Victorian DNSPs each received $500 000 in the prior period to cover these costs. SGC also considered that there were very few changes to the data for each light on a yearly basis, or even during the life of each light.[128]

SGC also noted that:

> the distributors are required to keep this data (except spatial location) to meet their obligations as MP and MDA under the Metrology Rules - and not the Public Lighting Code.[129]

SGC also submitted that the Victorian DNSPs already receive payment of a network use of service (NUOS) charge for maintaining inventory, light type and customer details. SGC noted that these NUOS charges would provide United Energy an amount in excess of $120 000 per annum.[130]

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124 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 398.
125 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 398.
126 SP AusNet, *Revised Regulatory Proposal*—public lighting model, July 2010.
127 SGC, *Submission to the AER*, August 2010, p. 10.
128 SGC, *Submission to the AER*, August 2010, p. 11.
129 SGC, *Submission to the AER*, August 2010, p. 11.
130 SGC, *Submission to the AER*, August 2010, p. 11.

SGC contended that there was a NUOS charge but no GIS component charge prior to 2005 and that this GIS charge:

> must be removed from public lighting OMR costs, or if retained, substantially reduced to a nominal cost for only when the spatial location needs to be changed.[131]

SGC also noted that SP AusNet has introduced a 'living away from home' allowance despite the fact that rural and remote services already attract a surcharge.[132]

19.6.6.4 AER considerations

The AER rejects SGC's claims regarding GIS costs. The draft decision noted that GIS component costs are required for the ongoing maintenance of the Victorian DNSPs' public lighting data. Without a GIS system, the Victorian DNSPs will not be able to track lights within their network in order to meet the minimum requirements set out in clauses 2.3.1, 5.1 and 5.2 of the Public Lighting Code, regarding provision of public lighting data to customers.[133] Accordingly, the AER maintains the positions established in its draft decision to allow an annual GIS component cost of $100 000 for each Victorian DNSP.

With regards to SGC's claims that network use of system (NUOS) charges recovers GIS costs, the AER disputes this. NUOS charges recover the costs of energy consumption only. Therefore, SGC's claims are rejected.

The AER acknowledges that while SP AusNet receives a five per cent premium in costs for rural and remote areas, this premium is only applied to material costs. The AER acknowledges that this premium is not applied to operational costs, such as labour and vehicles, associated with servicing lights in those areas. The AER also accepts SP AusNet's explanation that the proposed costs cover requirements of the 'living away from home allowances'.[134]

The AER further acknowledges that SP AusNet would be obliged to pay crews working in rural and remote areas an allowance to cover accommodation and meals when required to stay overnight. The AER considers that this may be more efficient than having crews return to an urban depot and then back to the same or similar work location on the following day.

Accordingly, the AER accepts the SP AusNet's 'other costs' for north and east regions, including the unit cost of $1.25 to be applied to the bulk change and repair of MV80 and T5 lights.

19.6.6.5 AER conclusion

The AER's final decision is to approve annual GIS costs of $100 000 for each Victorian DNSP, and to approve the other costs for north and east regions for SP AusNet.

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131 SGC, *Submission to the AER*, August 2010, p. 11.
132 SGC, *Submission to the AER*, August 2010, p. 18.
133 AER, *Draft decision*, June 2010, p. 807. See also Public Lighting Code, pp. 2, 7–8.
134 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 398.

19.7 Issues and AER considerations—capital expenditure

19.7.1 Forecast replacement volumes of luminaires, poles and brackets in 2011–15

19.7.1.1 AER draft decision

The AER rejected United Energy’s proposed volumes of poles and brackets to be replaced during 2015, and reduced these volumes to:

- 284 poles and brackets in urban areas
- 54 poles and brackets in rural areas.

The AER noted that these amounts were equivalent to the average volume of forecast replacements over the period 2011 to 2014.[135]

The AER also rejected SP AusNet's proposed volumes of luminaires, poles and brackets to be replaced over 2011 to 2015, which were the main drivers of SP AusNet's significant increases in forecast public lighting capex.

SP AusNet’s total capex was observed to triple, from $5.1 million in the 2006–10 regulatory period to $15.6 million for the forthcoming regulatory control period. The AER noted that SP AusNet's proposal lacked evidence that the substantial increase in capex was efficient. Table 19.21 sets out the draft decision replacement volumes for SP AusNet.

[135] AER, *Draft decision*, June 2010, pp. 815–816.

Table 19.21 AER draft decision on SP AusNet's annual replacement volumes of luminaires, poles and brackets, 2011–15

	2011	2012	2013	2014	2015
MV80 luminaires					
Urban	535	455	407	407	407
Rural	135	115	103	103	103
Remote	26	22	20	20	20
S-HP150 luminaires					
Urban	242	246	249	253	257
Rural	68	69	70	71	73
Remote	6	6	6	6	6
S-HP250 luminaires					
Urban	141	143	145	148	150
Rural	62	63	64	65	66
Remote	5	5	5	6	6
Poles and brackets					
Urban	537	551	581	590	599
Rural	182	187	197	200	203
Remote	14	14	15	15	15
Brackets on non-dedicated poles					
Urban	870	894	942	956	971
Rural	294	302	318	323	328
Remote	22	23	24	25	25
Other luminaires					
Other light types (excluding T5s)	122	124	126	128	130

Source: AER, *Draft decision*–SP AusNet's public lighting model, June 2010.

The other Victorian DNSPs' proposed forecast capex was not substantially different to historic trends and was therefore accepted by the AER.[136]

19.7.1.2 Victorian DNSP revised regulatory proposals

CitiPower, Powercor, JEN and United Energy accepted the AER's draft decision.[137]

[136] AER, *Draft decision*, June 2010, p. 816.

SP AusNet has accepted the AER’s approach and reduced the number of pole and bracket replacements to 1.5 per cent.[138]

In terms of public lighting luminaires, SP AusNet submitted that more than 50 per cent of lighting assets are approaching the end of their 20 year life and would therefore require replacement during the 2011–15 regulatory control period. [139]

SP AusNet submitted that the AER's draft decision significantly under funded it to replace public lighting assets over 2011–15 and therefore failed to promote the long term interest of customers.[140]

SP AusNet's forecast capex to meet its public lighting obligations is in table 19.22.

Table 19.22 SP AusNet, total capex forecast, 2011–15 ($ '000, nominal)

	2011	2012	2013	2014	2015
Capital required to maintain	1 700	1 930	2 140	2 340	2 550

Source: SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 400.

19.7.1.3 Submissions

SGC supported the AER's draft decision to reject the Victorian DNSPs' proposed capex on the grounds that they were not efficient. SGC proposed that:

> To further assess the fairness of proposed distributor capex we would require to have (sic) the distributors provide the number of items by type, to be replaced and the cost per item.[141]

SGC also proposed the following:

- replacement of 3 per cent of brackets per year—this 3 per cent should be of brackets which have been in place for 30 years, not based on current inventory.
- the annual percentage of luminaires replaced should be applied to the inventory 20 years ago.[142]

19.7.1.4 AER considerations

The AER's draft decision stated:

> the AER reduced SP AusNet's forecast annual replacement volumes of luminaires, poles and brackets by 50 per cent for its draft decision.[143]

The AER acknowledges that its draft decision modelling had actually incorrectly reduced SP AusNet's proposed replacement volumes of MV80 lights by 75 per cent, instead of 50 per cent.

[137] United Energy, *Revised Regulatory Proposal*, July 2010, p. 345.
[138] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 398.
[139] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 397.
[140] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 399.
[141] SGC, *Submission to the AER*, August 2010, p. 12.
[142] SGC, *Submission to the AER*, August 2010, p. 12.
[143] AER, *Draft decision*, June 2010, p. 814.

Notwithstanding this, the AER notes that in June 2010 it served a revised Regulatory Information Notice (RIN) on SP AusNet, seeking data on replacement volumes of:

- MV80 luminaires (urban, rural and remote)
- S-HP150 and S-HP250 luminaires (urban, rural and remote)
- public lighting poles and brackets (urban, rural and remote)
- brackets on non-dedicated poles (urban, rural and remote).[144]

The AER notes that SP AusNet has not provided any of the historical replacement volumes data as requested in the AER's revised RIN.[145]

The AER observes that SP AusNet's revised public lighting model proposes an 81 per cent increase in total capex from $6.3 million in the 2006–10 regulatory period, to $11.3 million for the forthcoming regulatory control period.

The AER notes that a large part of this step up is driven by the proposed increase in capex for existing luminaires (from $1.8 million to $4.4 million), including forecast replacement volumes of MV80, S-HP150 and S-HP250 luminaires during 2011–15.[146]

Therefore, the AER considers it important to have regard to the relevant historical actual replacement volumes when assessing SP AusNet's proposed capex increases. As noted above, SP AusNet did not provide these in response to the revised RIN issued by the AER.

However, SP AusNet provided the AER with an age profile of its existing MV80, S-HP150 and S-HP250 luminaires which showed that a total of 13 920 luminaires were already older than 20 years.[147] This represents 13 per cent of the total stock of those luminaires in SP AusNet's network. From this information, the AER calculated that the capex required for SP AusNet's proposed luminaires replacements over the 2011–15 regulatory control period was approximately $4.48 million ($2010).[148]

Furthermore, the AER observes that customers have therefore benefited from SP AusNet's deferment of replacement capex for these luminaires which are older than 20 years, by being charged a lower OMR rate in the 2006–10 regulatory period.

However, these luminaires are well beyond their economic life of 20 years and will likely require replacement during the 2011–15 regulatory control period due to failures. Customers will thus be required to pay for this replacement through updated OMR charges.[149]

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144 AER, *Regulatory Information Notice to SP AusNet*–Electricity Distribution Revised Regulatory Templates–2.6c PL model inputs capex, June 2010.

145 AER, *Regulatory Information Notice to SP AusNet*, June 2010.

146 SP AusNet, *Revised Regulatory Proposal*–public lighting model, July 2010.

147 Email from SP AusNet to AER on 17 March. Also see SP AusNet, *Revised Regulatory Proposal*, July 2010, pp. 400–401.

148 Calculated from AER's final decision public lighting model for SP AusNet.

149 The ESCV's 2004 decision set the economic life of luminaires at 20 years, after which they are to be replaced. The AER has continued with this approach in the 2011–15 model. This is supported

Therefore, the AER considers this evidence supports SP AusNet's proposed replacement volumes and capex for existing luminaires over the 2011–15 regulatory control period. Accordingly, the AER accepts these replacement volumes for the forthcoming regulatory control period, which are presented in table 19.23.

Table 19.23 SP AusNet, replacement volumes of MV80, S-HP150 and S-HP250 luminaires, 2011–15

	2011	2012	2013	2014	2015
MV80					
Urban	2 141	1 820	1 629	1 629	1 629
Rural	540	460	411	411	411
Remote	105	89	80	80	80
S-HP 150					
Urban	484	491	499	507	515
Rural	136	139	141	143	145
Remote	12	12	12	13	13
S-HP 250					
Urban	282	286	291	295	300
Rural	124	126	128	130	132
Remote	11	11	11	11	11

Source: AER analysis.

SP AusNet accepted the AER's draft decision on the forecast replacement volumes of poles and brackets (and other luminaires) for the 2011– 15 regulatory control period. Accordingly, the AER affirms the replacement volumes for those components, as provided in table 19.21, for the final decision.

19.7.2 Costs of poles and brackets

19.7.2.1 AER draft decision

The draft decision rejected CitiPower's and Powercor's proposed cost of $3 125 for poles and brackets and set the costs at $500 in line with the ESCV's 2004 decision and AER's 2009 decision.

19.7.2.2 Victorian DNSP revised regulatory proposals

The revised regulatory proposals of CitiPower and Powercor stated that:

by clause 2.3.1(g) of the PLC requires distributors to replace luminaires with appropriate new luminaires at the end of their economic life.

> Upon further review CitiPower [and Powercor] observes that the figure appeared to contain labour and other costs not related to pole and bracket costs.[150]

Accordingly, these DNSPs proposed a revised cost of $1 351.30 for poles and brackets, "representing a weighted average of standard poles and brackets used", [151] supported by various vendor quotes.

19.7.2.3 Submissions

The AER notes that no submissions were received on this issue.

19.7.2.4 AER considerations

The AER has reviewed the information provided by CitiPower and Powercor and acknowledges the quotations from recommended vendors for poles and brackets. The information includes both 'standard' and 'non-standard' poles as well as brackets and the base. CitiPower and Powercor provided the AER with the following costs for poles only:

- weighted average costs of poles (both standard and non-standard) – $1 085.44
- weighted average costs of poles (standard only) – $1 117.86.[152]

In reviewing these costs, the AER notes that of the 544 poles supplied to CitiPower and Powercor in 2009, 316 of these were non-standard poles. CitiPower and Powercor have not provided the AER with any additional information or reasons to exclude non-standard poles from the calculation of the weighted average cost. The AER also notes that in responding to its enquiries, CitiPower and Powercor updated its weighted average costs of poles to include both standard and non-standard poles.[153]

Accordingly, the AER considers it appropriate to include both standard and non-standard poles in the calculation of the weighted average cost of the poles used by CitiPower and Powercor. Therefore the cost of poles (that is, excluding brackets) the AER accepts for both parties is $1 085.44.

The AER acknowledges CitiPower's and Powercor's proposed cost of $233.44 for brackets, which has been derived using the same approach used for poles. Accordingly, the AER's final decision on the costs of poles and brackets for CitiPower and Powercor will be $1 318.88.

In both their initial regulatory proposals and revised regulatory proposals, JEN, SP AusNet and United Energy proposed a pole cost of $500. The AER has no additional evidence on which to amend this cost for the respective DNSPs.

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150 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 451; Powercor, *Revised Regulatory Proposal*, July 2010, p. 453.

151 CitiPower, *Revised Regulatory Proposal*, July 2010, p. 452; Powercor, *Revised Regulatory Proposal*, July 2010, p. 453.

152 CitiPower, *Revised Regulatory Proposal*–Attachment 230 Quotations from vendors for costs or poles and brackets, July 2010; Powercor, Revised Regulatory Proposal–Attachment 230 Quotations from vendors for costs or poles and brackets, July 2010; Email from CitiPower and Powercor to the AER, 16 September 2010.

153 Email from CitiPower and Powercor to the AER, 16 September 2010.

Accordingly, the AER's final decision cost of poles and brackets for JEN, SP AusNet and United Energy is $500.

The AER will apply material cost escalation for steel, set out in table 19.15 earlier in this chapter, to the cost of public lighting poles.

19.7.2.5 AER conclusion

For CitiPower and Powercor, the final decision sets the cost of poles and brackets at $1 318.88.

For JEN, SP AusNet and United Energy, the AER's final decision is to set the cost of poles and brackets at $500.

19.7.3 Weighted average cost of capital (WACC) and CPI index

19.7.3.1 AER draft decision

The AER's draft decision on the real pre-tax WACC to be applied to each Victorian DNSPs' respective public lighting RABs in the forthcoming regulatory control period is shown in table 19.24.

Table 19.24 AER Draft decision on real pre-tax WACC (per cent)

	2011–15
CitiPower	7.46
Powercor	7.38
JEN	7.44
SP AusNet	7.30
United Energy	7.46

Note: The figures in this table have been rounded to two decimal places
Source: AER, *Draft decision*, June 2010, p. 817-818.

The AER also adopted a forecast annual CPI of 2.57 per cent for the forthcoming regulatory control period.

19.7.3.2 Victorian DNSP revised regulatory proposals

CitiPower and Powercor did not adjust their respective real pre-tax WACC for the forthcoming regulatory control period.[154]

JEN's revised regulatory proposal applied a real pre-tax WACC of 8.61 per cent in its public lighting model for the forthcoming regulatory control period.[155] SP AusNet and United Energy both submitted a revised WACC figure of 7.53 per cent.[156]

[154] CitiPower, *Revised regulatory proposal*–public lighting model, July 2010; Powercor, *Revised Regulatory Proposal*–public lighting model, July 2010.
[155] JEN, *Revised regulatory proposal*–public lighting model (Appendix 19.1), July 2010.
[156] SP AusNet, *Revised regulatory proposal*–public lighting model, July 2010; United Energy, *Revised Regulatory Proposal*–public lighting model, July 2010.

19.7.3.3 Submissions

Submissions on the WACC are set out in chapter 11 of this final decision.

19.7.3.4 AER considerations

The AER's consideration of the Victorian DNSPs' proposed WACC, together with submissions on the WACC, are set out in chapter 11 of this final decision. Consistent with the discussion in chapter 11, table 19.25 sets out the real-pre tax WACC applicable to each Victorian DNSP's respective public lighting RABs for the forthcoming regulatory control period.

Table 19.25 AER final decision on real pre-tax WACC (per cent)

	2011–15
CitiPower	7.37
Powercor	7.30
JEN	7.92
SP AusNet	7.41
United Energy	7.39

Note: The figures in this table have been rounded to two decimal places
Source: AER analysis.

19.7.4 Replacement of MV80 lights with T5 lights

19.7.4.1 AER draft decision

Table 19.26 sets out the AER's draft decision on the number of MV80 lights to be replaced by T5 lights for each Victorian DNSP for the forthcoming regulatory control period.

Table 19.26 AER draft decision replacement of MV80 lights with T5 lights, 2011–15

	2011	2012	2013	2014	2015
CitiPower	5 860	5 860	860	0	0
Powercor	25 409	25 409	20 409	0	0
JEN	3 362	3 068	3 596	3 701	3 500
SP AusNet - Central	7 053	7 163	4 269	0	0
SP AusNet – North & East	3 221	3 272	1,950	0	0
United Energy	3 000	3 000	3 000	3 000	3 000

Source: AER, *Draft decision*–Victorian DNSP public lighting models, June 2010.

19.7.4.2 Victorian DNSP revised regulatory proposals

The AER notes that CitiPower, Powercor and United Energy did not depart from the forecast replacement numbers in the draft decision.

JEN noted that the forecast replacements of MV80 lights for T5 lights in its original proposal was based on the interest shown by municipal councils in its distribution area. JEN explained that following a tender process in response to the councils' requests for the prices of retrofitting, JEN indicated that the price would be $291.70 per retrofit in 2009.[157]

Following their manufacturers' (Pierlite Pty Ltd) price increases for T5s (of 25 percent to $390), JEN expected 25 per cent fewer MV80s to be replaced with T5s than previously forecast or set out in the AER's draft decision.[158]

JEN also submitted that:

> Currently as at July 2010 no council in JEN's distribution area has made requests or commitments to retrofit MV80's with the new T5 installation in the current year. It was JEN's expectation when forecasting November 2009 that matters between councils and JEN would have been more advanced in terms of the T5 take up than they currently are. As a result of the slower take up in February 2010, JEN adjusted the forecast for 2010 to zero and forecast the the [sic] commencement of the roll out of T5 lights to begin in 2011.[159]

JEN's forecast replacement of MV80 lights with T5 lights in its revised regulatory proposal are provided in table 19.27.

Table 19.27 JEN's revised forecast take-up rate of retrofitting MV80 lights with T5 lights per year, 2011–15

	2011	2012	2013	2014	2015
JEN revised proposal	2 291	2 348	2 772	2 863	2 711

Source: AER, *Draft decision*–Victorian DNSP public lighting models, June 2010; JEN, *Revised regulatory proposal*–public lighting model, July 2010.

SP AusNet has also included revised volumes of forecast replacements of MV80 lights with T5 lights in its revised public lighting model, as provided in table 19.28.

Table 19.28 SP AusNet's revised forecast take-up rate of retrofitting MV80 lights with T5 lights per year, 2011–15

	2011	2012	2013	2014	2015
SP AusNet revised model - central	7 163	4 269	0	0	0
SP AusNet revised model – north & east	3 272	1 950	0	0	0

Source: AER, *Draft decision*–Victorian DNSP public lighting models, June 2010; SP AusNet, *Revised Regulatory Proposal*–public lighting model, July 2010.

157 JEN, *Revised regulatory proposal*, July 2010, p. 321.
158 JEN, *Revised regulatory proposal*, July 2010, p. 321.
159 JEN, *Revised regulatory proposal*, July 2010, p. 321.

19.7.4.3 Submissions

No submissions were received on this issue

19.7.4.4 AER considerations

The AER has considered the revised inputs and information provided by JEN, including Pierlite's advice on the price increase for T5 lights.

The AER is persuaded that a price increase in T5 lights will negatively impact on the number of MV80s to be replaced by T5 lights. Accordingly, the AER accepts JEN's and SP AusNet's revised forecasts accordingly.

The AER's final decision on the number of MV80 lights replaced by T5 lights for each Victorian DNSP is provided in table 19.29.

Table 19.29 AER final decision on number of MV80 lights replaced with T5 lights per year, 2011–15

	2011	2012	2013	2014	2015
CitiPower	5 860	5 860	860	0	0
Powercor	25 409	25 409	20 409	0	0
JEN	2 291	2 348	2 772	2 863	2 711
SP AusNet – Central	7 163	4 269	0	0	0
SP AusNet – North & East	3 272	1 950	0	0	0
United Energy	3 000	3 000	3 000	3 000	3 000

Source: AER analysis.

19.7.5 Funding for the installation of T5 lights

19.7.5.1 AER draft decision

The AER noted that any joint funding arrangements between the Victorian DNSPs and councils for retrofitting T5 luminaires (or other new luminaire types) in place of existing luminaires, is a commercial decision for these parties.[160] That is, this service is a negotiated service which is separate from the ongoing OMR charge for these lights.

On this basis, the AER subsequently rejected SP AusNet's assertion that it funds $94.55 of the capital cost of T5 lights, which councils may wish to install.

19.7.5.2 Victorian DNSP revised regulatory proposals

With regard to luminaires, SP AusNet noted that it accepts the AER determination on prices for energy efficient light types (that is, T5 lights). With regard to setting OMR charges SP AusNet submitted that:

[160] AER, *Draft decision*, June 2010, p. 816.

> there is little difference between prices that are established using a model that is based on a distributor funding the initial installation plus the recovery of operating and maintenance costs or the customer/third party funding the initial installation and the distributor recovering the operating and maintenance costs plus the capital to fund the outturn of the light at the end of its life. Provided the former pricing model recognises a notional capital and not actual capital where the practice follows the latter approach prices will be similar under either option.
>
> However, where the practice follows the latter approach the use of the distributor's asset base to determine written down values and replacement costs of the assets is flawed. The assets on a distributors register will not be representative of the entire population, rather it represents that small portion that has been funded by the distributor as a result of replacement due assets reaching the end of their physical life, damage by accident or vandalism, or partial funding of small schemes where the installation cost exceeds the quoted price.[161]

19.7.5.3 Submissions

SGC submitted that councils, not Victorian DNSPs, pay for the capital cost of replacement lights and OMR charges must be reduced in recognition.[162]

19.7.5.4 AER consideration

In response to SP AusNet's revised proposal, the AER considers that there is a difference between:

- a DNSP funding the initial installation plus the recovery of operating and maintenance costs.
- the customer (council) or third party funding the initial installation and the DNSP recovering the operating and maintenance costs plus the capital to fund the replacement of the light at the end of its life.

The AER notes that installing or retrofitting a new type of public lighting asset, such as a T5 light, is a negotiated service and falls under the negotiated distribution service framework, as determined in the AER's Framework and approach paper and discussed in the AER's 2009 final decision on energy efficient public lighting.[163] This is a separate service to the operation, maintenance and replacement of existing DNSP owned assets.

The AER notes that where a council requests a DNSP to retrofit a new type of public lighting asset (for example, T5), the DNSP is not required under its distribution licence, or the PLC, to fund the capital cost for the new asset up front.

The AER maintains that any joint funding arrangements between the Victorian DNSPs and councils for retrofitting T5 luminaires (or other new luminaire types) in place of existing luminaires, is a commercial decision for these parties.

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161 SP AusNet, *Revised Regulatory Proposal*, July 2010, pp. 399–400.

162 SGC, *Submission to the AER*, August 2010, p. 12.

163 AER, *Framework and approach paper*, May 2009, p. 60; AER, *Energy efficient public lighting charges–Victoria (final)*, February 2009, p. 6.

The funding costs do not form part of the public lighting model and regulated charges for public lighting alternative control services. Such arrangements would however be subject to the negotiated services framework set out in chapter 3 of this final decision.

Therefore, the AER rejects SP AusNet's revised proposed capex for energy efficient lights and has removed its $94.55 funding component from its capex proposal.

The AER notes this adjustment has reduced SP AusNet's total 2011–15 forecast capex for energy efficient lights by $2.52 million. It has also reduced SP AusNet's annual OMR charges for T5 lights in the 2011–15 regulatory control period by an average of $8.11 for T5 (2x14W) luminaires and $8.99 for T5 (2x24W) luminaires.

The AER has not accepted SCG's assertion that councils pay for the capital cost of replacement lights and that because of this, OMR charges should be reduced. The AER notes that future capex replacement costs of public lighting assets are funded by the Victorian DNSPs and rolled into the public lighting regulatory asset base, after which a return on and of these assets is recovered from councils.

19.8 Issues and AER considerations—other matters

19.8.1 Introduction of new lighting types during 2011–15

19.8.1.1 AER draft decision

The AER noted that in September 2009 a public lighting Memorandum of Understanding (MOU) was entered into between:

- The Victorian DNSPs
- VicRoads
- Victorian Local Government Association
- Municipal Association of Victoria
- Victorian Department of Sustainability and Environment.[164]

The AER noted that this MOU specifically set out procedures for introducing new lighting technologies at any time in Victoria to meet environmental (and other) objectives.

The AER's Framework and approach paper classified the alteration and relocation of existing DNSP public lighting assets and the provision of new public lighting assets, as negotiated services—noting the regulatory arrangements under the PLC and Guideline 14.[165] Under these arrangements, public lighting services can be provided

[164] AER, *Draft decision*, June 2010, pp. 818–819.

[165] The AER also had regard to clause 6.2.1 of the NER, in particular, the matters set out in clause 6.2.1(c) and (d) of the NER such as the form of regulation previously applicable to the relevant service. See also AER, *Framework and approach*, May 2009, p. 4.

by parties other than the Victorian DNSPs, such as VicRoads and local councils, or other third parties.[166]

The AER's draft decision classified alteration and relocation of existing DNSP public lighting assets and the provision of new public lighting assets as negotiated services.

The AER noted that new public lighting assets also refer to assets constructed in new residential and commercial subdivisions by parties other than the DNSP.

The AER understands that under Victorian arrangements, these assets are (usually) vested to the Victorian DNSPs upon connection to the relevant electricity distribution network. The DNSP is then responsible for the associated operation, maintenance, repair and replacement of these assets under the PLC.

If the asset is not vested to the DNSP, the third party provider is responsible for the associated operation, maintenance, repair and replacement of these assets.[167]

New technology public lighting assets constructed from 1 January 2011 which are not regulated as public lighting alternative control services under the AER's distribution determination, are considered by the AER to be 'new assets' and therefore subject to the AER's negotiating criteria and the relevant DNSP's negotiating framework.

Accordingly, councils and Victorian DNSPs can negotiate a charge for new lighting technology that did not exist at the time of the relevant DNSP's regulatory proposal or the AER's final distribution determination.[168]

The AER notes that it is not empowered under the NER to consider or request ad-hoc proposals for public lighting charges where a distribution determination is already in force. The introduction of any new lighting technology during the 2011–15 regulatory control period will therefore be on a negotiated basis. Chapter 3 of this final decision sets out the approach to negotiated distribution services.[169]

19.8.1.2 Victorian DNSP revised regulatory proposals

SP AusNet submitted that it operates its public lighting as a single system across its distribution area and across all light types. The differences between the systems are in respect to the different types of poles that are available not the light types utilised. SP AusNet also stated that:

> any decision that treats different light types in a different manner has the effect of undermining the existing public lighting system. This in turn would lead to additional costs for all light types as separate systems are established to capture and record data for the different light types. Given that this is not the status quo each DNSP would need to reassess the costs that would be incurred in this regard.[170]

SP AusNet expressed its disappointment that:

[166] AER, *Draft decision*, June 2010, p. 819.
[167] AER, *Draft decision*, June 2010, p. 819.
[168] AER, *Draft decision*, June 2010, p. 819.
[169] AER, *Draft decision*, June 2010, p. 819.
[170] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 400.

> the AER has chosen an approach that in time will lead to the fragmentation of the public lighting system.[171]

It considered that higher public lighting costs would result.[172]

19.8.1.3 Submissions

SGC supported the AER's view in its draft decision that the PLC enables the alteration and relocation of existing assets and provision of new public lighting as a negotiated service.

However, SGC explained that one council indicated that:

> Negotiated Distribution Services are a disincentive to introduce these energy efficient lights due to the one sided nature of such negotiations and the lack of realistic alternatives for customers.[173]

SGC therefore expressed disappointment that CFLs were not included in the draft decision, despite being an approved luminaire by several DNSPs.[174]

SGC suggested that there are potential conflicts in establishing regulated charges on a negotiated distribution service framework, including:

> having the same service (OMR) split between Alternative Controlled Distribution Services and Negotiated Distribution Services is potentially problematic for all parties concerned (i.e. the AER, distributors and customers) when it comes to establishing rates fro [sic] the service.[175]

SGC also suggested there will be problems when:

> apportioning costs between the Alternative Controlled Distribution Services and Negotiated Distribution Services eg overhead, profit, GIS, call centres etc.[176]

SGC argued that because a customer will potentially not be able to effectively negotiate with the DNSP, the AER should review OMR charges annually and remove any negotiated distribution services for OMR charged by the DNSP.[177]
SGC also proposed that the AER (re)considers OMR for public lighting as a negotiated distribution service for the current and the next regulatory control period 2016–20.[178]

On vesting new public lighting assets to the distributor, SGC advised that:

> distributors have been "requiring" that new public lights are vested to them otherwise more costly arrangements for connection were required by the distributor. In our previous Submission (sic) on the AER we advised we had concerns regarding this type of "requiring" or "forcing" under "Victorian

[171] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 400.
[172] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 400.
[173] SGC, *Submission to the AER*, August 2010, p. 13.
[174] SGC, *Submission to the AER*, August 2010, p. 13.
[175] SGC, *Submission to the AER*, August 2010, p. 13.
[176] SGC, *Submission to the AER*, August 2010, pp. 13–14.
[177] SGC, *Submission to the AER*, August 2010, p. 14.
[178] SGC, *Submission to the AER*, August 2010, p. 14.

> arrangements" in terms of Part IV of the Trade Practices Act 1974 (the Act), particularly sections 45, 46 and 47.[179]

SGC considered that the AER must address these concerns.

In correspondence between 30 August 2010 and 11 October 2010, SGC resubmitted matters regarding ownerships of public lights and the capital funding of lights.[180]

Sylvania raised concerns that the AER's draft decision did not include a regulated OMR charge for CFLs. Sylvania noted the Victorian DNSPs had now approved CFLs for use on their networks and had published "commercial rates" for CFLs on their websites (with charges lower than for T5s).

Therefore, Sylvania suggested that the AER should either include CFL charges in the final determination, or exclude both T5 and CFL's completely. Sylvania also recommended that, if the AER chose not to set CFLs charges in the final decision, it should reassure councils that they could approach the AER with any concerns they had about the Victorian DNSPs's proposed CFL charges.[181]

19.8.1.4 AER consideration

The AER notes SP AusNet's submission that it operates its public lighting as a single system across its distribution area and across all light types. The AER also notes that there may be costs associated with 'all light types as separate systems are established to capture and record data for the different light types'.[182]

In response to this, the AER notes that it has provided SP AusNet and the other Victorian DNSPs with $100 000 per annum for GIS over the forthcoming regulatory control period, as discussed in section 19.7.6 above. The AER notes that SP AusNet had stated that the GIS was fundamental to the management of its public lighting system, and that it serves as the primary record of lights connected to the SP AusNet network.

Accordingly, the AER is satisfied that the $100 000 per annum for GIS costs provided to the Victorian DNSPs is sufficient to capture and record data for the different light types.[183]

In addition, the AER reiterates that the classification of public lighting services was considered at length in its Framework and approach paper.[184] The AER considered, for the reasons discussed in that paper, including the existing regulatory regime in Victoria and the various matters in respect of classification in clause 6.2.1 of the NER, that there were cogent reasons for classifying public lighting services that had been treated as 'excluded services' by the ESCV as alternative control services.

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179 SGC, *Submission to the AER*, August 2010, p. 14.

180 These matters are substantially the same as those set out in the AER's draft decision at page 820.

181 Sylvania Lighting Australasia, *Comments – Draft decision Victorian electricity DNSPs distribution determination 2011–2015*, 10 June 2010, p. 2.

182 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 400.

183 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 400.

184 AER, *Framework and approach paper*, May 2009, p. 45.

Similar consideration was given by the AER to the classification of the alteration and relocation of existing DNSP public lighting assets and new public lighting as negotiated distribution services. In accordance with clause 6.12.3(b) of the NER, the AER does not consider that, in light of SP AusNet's regulatory proposal and submissions received, there are good reasons from departing from these classifications.

With regard to SGC's submission, the AER maintains that new technology public lighting assets which are constructed from 1 January 2011 and not regulated as public lighting alternative control services are considered by the AER to be 'new assets'.

As noted earlier, such assets are subject to the AER's negotiating criteria and the relevant DNSP's negotiating framework. Correspondingly, councils and Victorian DNSPs can negotiate a charge for a new lighting technology that did not exist at the time of the relevant DNSP's regulatory proposal or the AER's final determination.

Moreover, the AER notes that councils are able to approach third party service providers to negotiate the installation of new CFL lights.

The AER acknowledges, but does not accept, SGC's concerns about asset vesting, noting that the Victorian DNSPs have previously advised that they are open to assets not being vested to them provided technical and safety requirements have been met.[185]

In terms of the ownership and capital funding of public lights, the AER considers that SGC has not raised any new matters. Accordingly the AER maintains its views and positions established in its draft decision.[186]

19.8.1.5 AER conclusion

The AER considers that the $100 000 per annum for GIS costs is sufficient to meet upgrades to the Victorian DNSPs' information reporting systems on luminaire types in their network.

19.8.2 Ownership of public lighting assets

19.8.2.1 AER draft decision

The AER noted that its 2009 decision and the ESCV's 2004 decision rejected SGC's claim that public lighting assets are owned by municipal councils.[187]

The ESCV's 2004 investigation determined that the financing of new public lighting installations by the customer, referred to in a 1993 State Electricity Commission of Victoria (SECV) letter did not recover any costs associated with the replacement of the public lighting assets in later years. Asset ownership was vested by the Victorian government to the DNSPs during electricity industry privatisation in the mid 1990s.

The AER noted in its draft decision that, it has no role in determining the ownership of the assets vested at the time of privatisation and that if municipal councils dispute

185 ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision,* August 2004, p. 98, and verbal advice provide by SP AusNet to AER staff on 14 September 2010.

186 See AER, *Draft decision,* p. 820.

187 ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision,* August 2004, pp. 96–98; AER, Energy Efficient Public Lighting charges—Victoria (Final), February 2009, p. 17.

asset ownership, it would be appropriate for the councils to raise this with the Victorian government.

19.8.2.2 Victorian DNSP revised regulatory proposals

In its revised proposal SP AusNet considered that the AER had made some incorrect assumptions on public lighting asset ownership, specifically:

> where new lights are constructed by other parties and connected to the SP AusNet distribution network and no explicit statement is made by a public lighting customer as to the ownership of the lights, they must default to the distributor and not to the public lighting customer.[188]

SP AusNet also noted that:

> the inevitable outcome of any other approach will result in increased costs to the provision of public lighting services as the system becomes more and more fragmented and the fixed costs of all operators are recovered over fewer lights.[189]

19.8.2.3 Submissions

SGC was concerned that local councils were funding the capital cost of assets rather than disputing asset ownership per se.[190]

SGC acknowledged that the AER has no role in determining the ownership of assets vested at the time of privatisation. SGC was of the view that the AER had not considered that the State Electricity Commission of Victoria's tariff charges were:

- reduced to reflect removing the capital component from the tariff
- applied to all lanterns on current offer irrespective of the date they were installed.[191]

SGC also noted the ESCV's 2004 Review reintroduced a capital component to the OMR charge. SGC considers that:

> by treating the cost of replacement lights, poles and brackets as being funded by distributors and not by councils, the ESCV built in an automatic annual increase that will see OMR charges increase to $86.90 (i.e. more than trebling from $26.69) by 2035 without any consideration of CPI movements and for no changes in the services being received by councils.[192]

SGC submitted that based on the total public lighting inventory of around 450,000 lights, public lighting customers would be paying approximately $25 million per annum extra under the ESCV’s 2004 decision methodology. SGC expressed its concern that the ESCV’s approach has been largely adopted by the Victorian DNSPs in their modelling of OMR charges.[193]

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188 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 401.
189 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 401.
190 SGC, *Submission to the AER*, August 2010, p. 15.
191 SGC, *Submission to the AER*, August 2010, p. 15.
192 SGC, *Submission to the AER*, August 2010, p. 15.
193 SGC, *Submission to the AER*, August 2010, p. 15.

Finally, SGC proposed that the current modelling adopted by the Victorian DNSPs and the AER for determining the replacement costs component in the OMR is critically flawed as it assumes distributors fund the replacement lights.

SGC submitted that the OMR tariff must be reduced to recognise that councils, not Victorian DNSPs, pay for the capital costs of replacement lights through a component in the OMR charge.[194]

19.8.2.4 AER consideration

The AER considers that SGC's submission is premised on questionable assumptions about asset ownership, principally that customers (councils) own the luminaires presently installed on the Victorian DNSPs networks and therefore should not pay for their operational or capital costs.

Councils pay for the opex incurred and forecast by the Victorian DNSPs on public lighting plus any capital incurred and forecast by the Victorian DNSPs when the luminaire needs replacing over its operating life. Councils have not and do not fund this capital. The Victorian DNSPs fund capex costs and recoup the costs through the OMR charge.

The AER affirms the view expressed in the draft decision that existing public lighting assets are owned by the Victorian DNSPs. The AER reiterates that it does not determine such matters and it cannot make a constituent decision on such matters under clause 6.12.1 of the NER.

19.8.3 Contestability of public lighting

19.8.3.1 AER draft decision

The AER noted that the Service and Installation Rules (2005) (SIRs) are an industry wide formal standard (but not a regulatory standard) that helps the Victorian DNSPs and other service provides to comply with regulatory and electricity supply obligations.

The SIRs form the major part of the Victorian DNSPs’ 'reasonable technical requirements' referred to in the Electricity Distribution Code, and are set by the Victorian Service Installation Rules Management Committee.[195]

The AER observed that clause 7.8.5 of the SIRs notes that agreement between the Victorian DNSPs and other parties is required before equipment may be installed on a DNSP’s pole.[196]

The AER also noted that the PLC, which must be adhered to by customers and the Victorian DNSPs and observed by the AER, defines 'public lighting assets' as meaning:

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194 SGC, *Submission to the AER*, August 2010, pp. 14–15.

195 Made up of representatives from each of the Victorian DNSP and at the time the SIR’s were written, advisers from the Office of the Chief Electrical Inspector and National Electrical and Communications Association.

196 Clause 7.8.5 of the Victorian Service & Installation Rules (2005), pp. 7-50–7-52.

> all assets of a distributor which are dedicated to the provision of public lighting, including lamps, luminaires, mounting brackets and poles on which fixtures are mounted, supply cables and control equipment (for example, photoelectric cells and control circuitry) but not including the distributor's protection equipment (for example fuses and circuit breakers).[197]

The AER noted that in determining whether 'new public lighting assets' are contestable, clause 1.3 of the PLC makes it clear that the PLC only applies to public lighting assets owned by the Victorian DNSPs. It would appear, therefore, that the installation of new assets is contestable under the PLC.

However, the AER notes that there are certain processes in place if alterations are to be made to existing assets. These are set out in clause 4.4 of the PLC. For example, a customer must, among other matters, obtain the DNSP's approval of the person who undertakes this work.[198]

Related to this, clause 4.4 of the PLC and the SIRs both require the agreement between the DNSP and the respective parties to replace one asset with another—in this case, an existing DNSP owned public light on a DNSP owned pole, with a new energy efficient light, constructed and installed by a third party provider other than the DNSP.

Accordingly, the AER considered that the replacement, relocation and alteration of existing assets and the installation of new public lighting assets are contestable under clause 4.4 of the PLC.

As discussed previously, such services are classified as negotiated services in this final decision and would be subject to the AER's negotiating criteria and the relevant DNSP's negotiating framework.

19.8.3.2 Victorian DNSP revised regulatory proposals

All Victorian DNSPs agreed with the draft decision regarding the contestability of public lighting assets.[199]

19.8.3.3 Submissions

SGC noted that in general terms, it supports the AER's views regarding contestability. However, SGC raised the following issues for the AER's consideration:

> - The Public Lighting Code (PLC) only applying to distributor owned assets is preventing the effective development of the market and we propose a review of the PLC.
>
> - SGC agrees with and supports the AER's determination that the replacement, relocation and alteration of existing assets and the installation of new public lighting assets are contestable under clause 4.4 of the PLC.[200]

197 ESCV, *Public Lighting Code*, April 2005, p. 10.
198 ESCV, *Public Lighting Code*, April 2005, p. 6.
199 SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 401.
200 SGC, *Submission to the AER*, August 2010, p. 16.

19.8.3.4 AER consideration

As the PLC only applies to the Victorian DNSPs' assets, the AER does not agree with SGC that it prevents effective development of the market because new public lighting does not need to be vested to the Victorian DNSPs and can therefore be operated by third parties. The Victorian DNPSs however, are entitled to recover the costs of operating public lighting assets they own.

Any review of the PLC should be raised with the ESCV as the AER does not have power to amend ESCV codes and guidelines.

19.8.4 Information requirements

19.8.4.1 AER draft decision

In anticipation of assessing the 2016–20 OMR charges and consistent with the AER's 2009 final decision, the AER noted in its draft decision that Victorian DNSPs will be required to report actual capex between energy efficient luminaires and existing luminaires.

The AER anticipated specifying formal reporting requirements in a RIN.

19.8.4.2 Victorian DNSP revised regulatory proposals

SP AusNet submitted that establishing separate records for energy efficient and non-energy efficient lights will lead to additional costs for which no allowance has been made.[201] The additional costs are the result of having to establish systems:

- to capture separately the costs for the different light types
- establish and maintain recording systems for the different light types
- establish and maintain reporting systems for the different light types.[202]

SP AusNet noted that for example:

> in this regard work crews currently work on a range of light types throughout the day, their costs are captured and recorded according to their time being spent on public lighting capital works or maintenance works. In future they will be required to allocate their time between capital works for energy efficient lights or others light types, maintenance for energy efficient lights or other light types. Vehicles used will need to be allocated throughout the day as the crew changes from one light type to another.[203]

19.8.4.3 Submissions

The AER notes that no submissions were received on this issue.

19.8.4.4 AER considerations

The AER considers that the $500 000 allocated to each DNSP for GIS costs in the current regulatory control period will enable it to undertake capex reporting. The AER

[201] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 401.
[202] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 401.
[203] SP AusNet, *Revised Regulatory Proposal*, July 2010, p. 401.

also considers that the $500 000 allowance for each DNSP for GIS costs over the 2011–15 regulatory control period will be sufficient to meet the ongoing costs of reporting.

Chapter 21 of this final decision outlines the AER's outcomes monitoring and compliance framework. The AER will undertake further consultation with Victorian DNSPs and other stakeholders to determine the specific form of the outcome measures for Victorian DNSPs to report against as part of a separate RIN process.

19.8.5 Control mechanism for public lighting OMR services including price paths and compliance with the control mechanism

19.8.5.1 AER draft decision

Control mechanism for public lighting OMR services including price paths

The AER's draft decision noted that a CPI-X approach will be used to establish a price path for alternative control services.

Compliance with the control mechanism

The AER's draft decision noted that compliance with the control mechanism was to be demonstrated by the Victorian DNSPs through the annual pricing proposal, by updating the forecast CPI for the actual CPI each year.

19.8.5.2 Victorian DNSP revised regulatory proposals

Control mechanism for public lighting OMR services including price paths

CitiPower and Powercor contend that it is appropriate to apply 'X factors' to the unit rates of public lighting services. These 'X factors' are consistent with the escalators proposed in Chapter 8 of CitiPower's and Powercor's respective revised regulatory proposals.

CitiPower's and Powercor's proposed X factors are provided in table 19.30.

Table 19.30 Proposed X factors for public lighting (real), per cent

	2012	2013	2014	2015
CitiPower	(0.9)	2.3	1.4	1.5
Powercor	(0.9)	2.3	1.4	1.5

Source: CitiPower, *Revised regulatory proposal*, July 2010, p. 453; Powercor, *Revised regulatory proposal*, July 2010, p. 455.

Compliance with the control mechanism

The Victorian DNSPs accepted the AER's draft decision regarding the control mechanism to be applied to public lighting services and compliance with the control mechanism in 2011–15.

19.8.5.3 Submissions

The AER notes that no submissions were received on either issue.

19.8.5.4 AER consideration

Control mechanism for public lighting OMR services including price paths

The price smoothing mechanism acts as the 'X' in the public lighting model. Therefore, no further additions are required. The AER will apply the relevant costs escalators to various input costs as set out in this final decision.

The control mechanism applying to public lighting services is a cap on charges for each regulatory year of the regulatory control period and is in the form CPI-X. This is described in the public lighting model, where real price movements take the form of the 'X'.

The 'X' is implied by the annual smoothing factor within the model, which the AER has set at 20 per cent for each Victorian DNSP.

Compliance with the control mechanism

DNSPs are to ensure compliance with the control mechanism, in accordance with clause 6.12.1(13) of the NER, by submitting, at the time of their initial pricing proposal for 2011 and each pricing proposal for each subsequent regulatory year of the forthcoming regulatory control period, actual annual CPI as measured by:

a. the all groups index for the eight state capitals as published by the Australian Bureau of Statistics for the September quarter immediately preceding the starts of the calendar year, divided by

b. the all groups index for the eight state capitals as published by the Australian Bureau of Statistics for the September quarter immediately preceding the previous September quarter.

In the public lighting models provided by the Victorian DNSPs with their respective pricing proposal, the AER will substitute the actual CPI for the forecast CPI and approve public lighting OMR charges where the CPI conforms to the methodology described above.

19.9 AER conclusion

The AER has assessed the public lighting expenditure forecasts and associated charges proposed by each of the Victorian DNSPs. The AER has assessed the forecast expenditure including conducting an assessment of the reasonableness of each of the labour, materials and other cost inputs for the forecast opex and capex.

As set out in this chapter, the AER has accepted SP AusNet's revised labour rates and also approved CitiPower and Powercor's originally proposed labour rates. The AER has maintained the labour rates for the other Victorian DNSPs as set out in its draft decision. The AER has adopted the labour escalators from appendix K of this final decision.

The AER has accepted the patrol and elevated platform vehicle cost increases as proposed by CitiPower, Powercor and SP AusNet.

The AER has not accepted the Victorian DNSPs' revised materials cost escalators and has instead adopted the escalators from appendix K of this final decision.

The AER also accepted the revised T5 luminaire cost for CitiPower and Powercor.

The AER has not accepted CitiPower's and Powercor's revised traffic management costs on the basis that these costs do not represent efficient costs in accordance with the NEL. Further, the AER did not receive sufficient information to be convinced that the draft decision traffic management unit costs should be amended for the final decision.

The AER has not accepted the Victorian DNSPs' proposals for higher MV80 and T5 failure rates. In adopting the statistical information provided by SP AusNet, the AER has revised its failure rates of MV80 lights. The AER has also updated the draft decision failure rates for T5 lights taking into account more recent information from VSPLAG.

The AER accepts SP AusNet's proposed 'living away from home' costs allowances, noting that SP AusNet would be obliged to pay crews working in rural and remote areas an allowance to cover accommodation and meals when required to stay overnight. The AER notes that this may be more efficient than having crews return to a depot and then back to the same or similar work location on the following day.

The AER also maintained its draft decision to provide each Victorian DNSP with $100 000 per annum in GIS costs for the maintenance of their public lighting inventory data.

The AER's concludes that SP AusNet's revised replacement volumes of luminaires, poles and brackets represent efficient capex requirements for the forthcoming regulatory control period, in accordance with the RPP, and in particular, s. 7A(2) of the NEL.

The AER also accepted CitiPower's and Powercor's revised cost for poles and brackets based on information from suppliers' quotations.

The AER also accepted JEN's and SP AusNet's revised volumes for the forecast replacement of MV80 lights with T5 lights during 2011–15.

The AER maintained its draft decision not to accept SP AusNet's proposal that it funds $94.55 of the cost of T5 lights, including those which replace MV80 lights. Accordingly, the AER has removed this $94.55 cost component from SP AusNet's capex requirements.

The AER has adopted the WACC and CPI used in other parts of this final decision.

In accordance with clause 6.12.1(12) of the NER, the control mechanism that will apply to the Victorian DNSPs' public lighting services is a cap on the charges for each year of the forthcoming regulatory control period. In accordance with clause 6.12.1(13) of the NER, the Victorian DNSPs' compliance with the control mechanisms for public lighting services is to be demonstrated through the annual pricing proposals.

19.9.1 AER conclusion on DNSPs' public lighting operational expenditure

Table 19.31 shows the AER's final decision total opex for each DNSP over the 2011–15 regulatory control period.

Table 19.31 AER final decision on total public lighting opex for 2011–15 ($, 2010)

	2011	2012	2013	2014	2015
CitiPower	2 000 529	2 047 194	2 087 464	2 136 624	2 173 437
Powercor	4 419 093	4 704 841	5 023 339	5 353 263	5 664 372
JEN	1 934 747	1 967 701	2 007 883	2 058 627	2 096 599
SP AusNet	4 076 438	4 298 367	4 607 425	4 778 324	4 919 624
United Energy	3 121 493	3 131 259	3 141 026	3 150 792	3 160 558

Source: AER analysis.

19.9.2 AER conclusion on DNSP's public lighting capital expenditure

Table 19.32 sets out the AER's final decision total capex for each DNSP over the 2011–15 regulatory control period.

Table 19.32 AER final decision on total public lighting capex for 2011–15 ($, 2010)

	2011	2012	2013	2014	2015
CitiPower	- 734 929	- 644 933	15 367	113 962	114 054
Powercor	-1 351 883	-1 023 149	- 483 734	297 229	297 543
JEN	894 726	271 126	548 427	281 891	773 490
SP AusNet	1 579 768	1 641 010	1 903 866	1 944 716	1 981 571
United Energy	1 812 577	1 670 717	1 905 423	1 506 967	1 474 787

Note: Negative capex figures are due to customer contributions for replacing existing lights (MV80) with energy efficient lights (T5), being greater than the DNSP's capex for existing lights.

Source: AER analysis.

19.9.3 AER conclusion on DNSPs public lighting charges

The AER's final decision public lighting charges for Victorian DNSPs over the 2011–15 regulatory control period is set out in tables 19.33 to 19.38.

These charges are also set out in the AER's distribution determination documents for CitiPower, Powercor, JEN, SP AusNet and United Energy.

Table 19.33 AER final decision on OMR charges, CitiPower, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	62.61	65.08	65.24	66.37	67.68
Sodium high pressure 150 watt	104.18	108.28	109.82	112.74	115.69
Sodium high pressure 250 watt	105.82	109.99	111.49	114.41	117.37
T5 2x14 watt	32.45	33.58	34.83	36.27	37.60
Fluorescent 20 watt	124.59	129.51	129.82	132.07	134.68
Fluorescent 40 watt	125.22	130.16	130.48	132.73	135.35
Mercury vapour 50 watt	88.90	92.41	92.64	94.24	96.10
Mercury vapour 125 watt	98.92	102.82	103.08	104.86	106.93
Mercury vapour 250 watt	88.89	92.39	93.65	96.10	98.59
Mercury vapour 400 watt	89.95	93.49	94.77	97.25	99.76
Mercury vapour 700 watt	132.27	137.49	139.37	143.01	146.71
Sodium high pressure 70 watt	132.73	137.97	138.30	140.70	143.48
Sodium high pressure 100 watt	106.26	110.44	112.02	115.00	118.01
Sodium high pressure 220 watt	106.03	110.21	111.72	114.64	117.60
Sodium high pressure 360 watt	107.93	112.19	113.72	116.70	119.72
Sodium high pressure 400 watt	116.40	120.99	122.64	125.85	129.11
Sodium high pressure 1000 watt	209.52	217.78	220.76	226.53	232.39
Metal halide 70 watt	204.73	212.81	213.33	217.02	221.30
Metal halide 100 watt	163.56	170.00	172.42	177.01	181.64
Metal halide 150 watt	164.60	171.08	173.52	178.14	182.80
Metal halide 250 watt	126.98	131.99	133.79	137.29	140.84
Metal halide 400 watt	126.98	131.99	133.79	137.29	140.84
Metal halide 1000 watt	189.41	196.88	199.57	204.79	210.09

Source: AER analysis.

Table 19.34 AER final decision on OMR charges, Powercor, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	41.22	44.32	53.05	52.19	52.45
Sodium high pressure 150 watt	75.14	79.02	84.17	84.96	86.65
Sodium high pressure 250 watt	77.74	81.80	87.21	87.85	89.49
T5 2x14 watt	28.93	29.95	31.10	32.32	33.36
Fluorescent 20 watt	114.59	123.22	147.49	145.09	145.80
Fluorescent 40 watt	114.59	123.22	147.49	145.09	145.80
Mercury vapour 50 watt	57.30	61.61	73.74	72.55	72.90
Mercury vapour 125 watt	55.65	59.84	71.62	70.46	70.80
Mercury vapour 250 watt	59.08	62.17	66.28	66.76	68.01
Mercury vapour 400 watt	68.41	71.98	76.75	77.30	78.75
Mercury vapour 700 watt	103.39	108.79	115.99	116.83	119.02
Sodium low pressure 90 watt	101.44	106.68	113.63	114.70	116.98
Sodium low pressure 180 watt	101.44	106.68	113.63	114.70	116.98
Sodium high pressure 400 watt	103.39	108.79	115.99	116.83	119.02
Incandescent 100 watt	114.59	123.22	147.49	145.09	145.80
Incandescent 150 watt	114.59	123.22	147.49	145.09	145.80
Metal halide 250 watt	103.39	108.79	115.99	116.83	119.02
Metal halide 400 watt	103.39	108.79	115.99	116.83	119.02

Source: AER analysis.

Table 19.35 AER final decision on OMR charges, JEN, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	37.88	40.13	42.26	44.69	47.45
Sodium high pressure 150 watt	73.34	77.05	80.77	85.04	89.53
Sodium high pressure 250 watt	75.18	79.02	82.84	87.23	91.87
T5 2x14 watt	24.69	25.63	26.76	28.12	29.45
Fluorescent 20 watt	47.36	50.16	52.82	55.86	59.31
Fluorescent 40 watt	47.36	50.16	52.82	55.86	59.31
Fluorescent 80 watt	47.36	50.16	52.82	55.86	59.31
Mercury vapour 50 watt	47.36	50.16	52.82	55.86	59.31
Mercury vapour 125 watt	55.69	58.99	62.12	65.69	69.75
Mercury vapour 250 watt	72.17	75.85	79.53	83.74	88.19
Mercury vapour 400 watt	81.19	85.34	89.47	94.21	99.22
Sodium low pressure 90 watt	77.74	81.68	85.62	90.14	94.90
Sodium high pressure 50 watt	91.68	96.32	100.96	106.29	111.91
Sodium high pressure 100 watt	100.48	105.56	110.66	116.50	122.66
Sodium high pressure 400 watt	99.98	105.09	110.18	116.01	122.18
Sodium high pressure 250 watt (24 hours)	117.27	123.26	129.24	136.07	143.31
Metal halide 70 watt	97.36	103.12	108.60	114.84	121.94
Metal halide 100 watt	162.82	171.06	179.31	188.78	198.76
Metal halide 150 watt	162.82	171.06	179.31	188.78	198.76
Metal halide 250 watt	161.63	169.88	178.11	187.54	197.52
Incandescent 55 watt	47.36	50.16	52.82	55.86	59.31
Incandescent 100 watt	59.10	62.60	65.92	69.71	74.02
Incandescent 150 watt	73.88	78.25	82.40	87.14	92.52

Source: AER analysis.

Table 19.36 AER final decision on OMR charges, SP AusNet, central region, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	36.56	39.47	42.21	45.03	47.76
Sodium high pressure 150 watt	83.81	88.80	93.88	99.27	104.30
Sodium high pressure 250 watt	84.83	89.90	95.04	100.49	105.58
T5 2x14 watt	32.57	33.99	35.23	37.09	38.81
T5 2x24 watt	37.03	38.61	40.03	42.08	43.97
Mercury vapour 50 watt	55.94	60.39	64.59	68.89	73.07
Mercury vapour 125 watt	53.75	58.02	62.05	66.19	70.20
Mercury vapour 250 watt	89.08	94.39	99.80	105.51	110.86
Mercury vapour 400 watt	92.47	97.99	103.60	109.53	115.08
Sodium high pressure 100 watt	89.67	95.02	100.45	106.21	111.60
Sodium high pressure 400 watt	120.46	127.65	134.96	142.69	149.92

Source: AER analysis.

Table 19.37 AER final decision on OMR charges, SP AusNet, north and east regions, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	42.36	45.59	48.67	51.80	54.82
Sodium high pressure 150 watt	94.77	100.31	105.99	112.01	117.62
Sodium high pressure 250 watt	93.98	99.49	105.14	111.12	116.69
T5 2x14 watt	38.03	39.62	41.05	43.13	45.04
T5 2x24 watt	42.58	44.34	45.95	48.22	50.30
Mercury vapour 50 watt	62.69	67.47	72.03	76.66	81.14
Mercury vapour 125 watt	62.69	67.47	72.03	76.66	81.14
Mercury vapour 250 watt	97.74	103.47	109.35	115.56	121.36
Mercury vapour 400 watt	100.56	106.46	112.50	118.90	124.86
Sodium high pressure 100 watt	101.40	107.33	113.41	119.85	125.85
Sodium high pressure 400 watt	133.45	141.28	149.30	157.79	165.70

Source: AER analysis.

Table 19.38 AER final decision on OMR charges, United Energy, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	48.84	52.21	55.84	59.47	62.99
Sodium high pressure 150 watt	78.25	82.34	86.71	91.10	95.40
Sodium high pressure 250 watt	79.56	83.79	88.30	92.83	97.26
T5 2x14 watt	25.25	25.88	26.65	27.65	28.63
Fluorescent 2x20 watt	63.01	67.35	72.03	76.71	81.25
Fluorescent 3x20 watt	63.01	67.35	72.03	76.71	81.25
Mercury vapour 50 watt	72.29	77.27	82.64	88.01	93.22
Mercury vapour 125 watt	72.29	77.27	82.64	88.01	93.22
Mercury vapour 250 watt	72.40	76.25	80.35	84.47	88.51
Mercury vapour 400 watt	100.25	105.58	111.26	116.96	122.55
Mercury vapour 700 watt	100.25	105.58	111.26	116.96	122.55
Sodium high pressure 70 watt	106.96	114.34	122.28	130.23	137.94
Sodium high pressure 100 watt	86.08	90.58	95.38	100.21	104.94
Sodium high pressure 400 watt	100.25	105.58	111.26	116.96	122.55
Metal halide 70 watt	105.64	111.16	117.05	122.98	128.79
Metal halide 100 watt	105.64	111.16	117.05	122.98	128.79
Metal halide 150 watt	105.64	111.16	117.05	122.98	128.79
Metal halide 250 watt	107.41	113.12	119.20	125.31	131.30
Metal halide 400 watt	107.41	113.12	119.20	125.31	131.30

Source: AER analysis.

20 Other alternative control services

This chapter sets out the AER's consideration of the Victorian Distribution Network Service Providers' (DNSPs') alternative control (fee based and quoted) services pricing and how compliance with the pricing control mechanism is to be demonstrated by the Victorian DNSPs in the forthcoming regulatory control period.[1] This chapter:

- summarises the draft decision on the Victorian DNSPs' alternative control services
- provides an overview of the DNSPs' revised regulatory proposals and stakeholder submissions on alternative control services
- details the AER's consideration of the relevant regulatory requirements in making this final decision on alternative control services prices and price paths for the forthcoming regulatory control period
- considers each of the issues raised relating to the Victorian DNSPs' fee based and quoted alternative control services in turn, as well as revised advice provided by the AER's consultant, Impaq Consulting (Impaq)
- sets out the AER's final decision on how compliance with the control mechanism will be monitored
- states the AER's final decision on each of the major issues raised.

The final decision prices and X factors for the form of control for the Victorian DNSPs' alternative control services are listed in appendix Q.

The AER's consideration of the Victorian DNSPs' public lighting (alternative control) services pricing control mechanism is set out in chapter 19 of this final decision. Classification of the Victorian DNSPs' alternative control services (including fee based and quoted services) is set out in chapter 2 of this final decision.

Generally, alternative control services are services that were previously classified as 'excluded services' under the Essential Services Commission of Victoria's (ESCV) 2006 Electricity Distribution Price Review (2006 EDPR) and are provided at the request of a customer. Alternative control services are divided into fee based services, quoted services and public lighting services.[2] This final decision entitles the Victorian DNSPs to levy charges for alternative control services over the forthcoming regulatory control period. Due to the sheer number of services and the variability between services provided by each of the Victorian DNSPs, the services and final decision prices are not listed in this chapter, however are listed in appendix Q.

Fee based services are those for which costs are generally discernable prior to undertaking the service, and do not vary significantly among customers, for example

[1] Due to their variable nature, quoted services are provided on the basis of a quotation by a DNSP for the materials and labour time required to provide the service. Fee based services are more standardised services with less variation between customers, and are accordingly provided on the basis of a fixed fee.

[2] Public lighting services are discussed in chapter 19 of this final decision.

re-energisation. For fee based services, the AER has determined a fixed fee per service for each DNSP where relevant.

Quoted services are more variable, dependent on the particulars of the service being provided, for example elective undergrounding of assets. For quoted services, this decision approves a set of applicable labour rates (inclusive of margins and all overheads) for each DNSP which can be applied to quoted services work as appropriate. Materials for quoted services are to be recovered at cost.

This final decision relates to manual services only. It does not set prices for the Victorian DNSPs' remote metering services which are facilitated by the rollout of advanced metering infrastructure (AMI) in Victoria. The regulatory arrangements relating to the AMI rollout are set out in an August 2007 Order in Council made by the Victorian Governor in Council under sections 15A and 46D of the *Electricity Industry Act 2000*. The Order in Council was amended on 25 November 2008, 22 January 2009 and 31 March 2009 (the 'revised Order'). Clause 3 of the revised Order requires that certain metering services (which the AER considers includes new remote services, such as remote energisation and remote special reads) will continue to be regulated as 'excluded services' during the forthcoming regulatory control period. In the current regulatory control period, excluded services were regulated under the Victorian DNSPs' distribution licences and the ESCV's Guideline 14. Accordingly, the AER will regulate the new services that are facilitated by AMI (including all remote services) under the Victorian DNSPs' distribution licences and Guideline 14 as part of a process that is separate to this final decision.

20.1 Regulatory requirements

Clause 6.8.1 of the National Electricity Rules (NER) requires the AER to publish a Framework and approach paper in anticipation of every distribution determination, which amongst other things includes the control mechanisms to apply to direct control services. Clause 6.2.2(a) of the NER states that direct control services are divided into subclasses of standard control services and alternative control services.

Clause 6.2.5(b) lists the control mechanisms that the AER may apply to direct control services. One mechanism the AER may apply is a cap on the prices of individual services, under clause 6.2.5(b)(2) of the NER.

Clause 6.2.5(d) of the NER outlines the factors the AER must have regard to in deciding on the control mechanism to apply to alternative control services, being:

- the potential for development of competition in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)

- any other relevant factor.[3]

Under clauses 6.12.1(12) and 6.12.1(13) of the NER, the AER's distribution determination must set out a decision on the control mechanism for alternative control services and how compliance with that control mechanism is to be demonstrated.

Clause 6.12.3(c) of the NER provides that the control mechanisms to be applied in a distribution determination must be as set out in the Framework and approach paper.

20.2 AER draft decision

The AER's draft decisions on the Victorian DNSPs' fee based and quoted alternative control service 2011 prices and price paths for 2012–15 (together being the control mechanism) was set out chapter 20 and in a series of tables in appendix O of the draft decision.

The 2011 prices and labour rates for fee based and quoted services approved by the AER in the draft decision drew upon the advice provided by the AER's consultant, Impaq Consulting (Impaq), specifically, the appropriate labour charge out rates and times taken to perform each service. A public version of Impaq's final report was released with the AER's draft decision.

The AER's analysis of the differing methodologies adopted by the Victorian DNSPs for calculating fee based alternative control services prices resulted in different prices for similar services across the DNSPs.

However, this variation reflected different price calculation methods and 2010 price starting points proposed by each DNSP.

In general, the AER found that a build up of costs resulted in higher proposed prices than a top down approach, although one DNSP's competitive tender process resulted in proposed prices significantly lower than the other DNSPs. Further details on the AER's draft decision are provided in the issues and considerations section below.

20.3 Victorian DNSP revised regulatory proposals

20.3.1 CitiPower and Powercor

In their revised regulatory proposals, CitiPower and Powercor stated that the AER's draft decision prices would not allow for the recovery of the efficient costs of providing fee based alternative control services.[4] CitiPower and Powercor proposed new prices for fee based alternative control services, based on their own internal and contract labour rates, times taken to perform services and profit margins.

Specifically, CitiPower and Powercor submitted that:

- profit margins—the AER should increase its accepted profit margin for alternative control services from 3 per cent to 5.7 per cent, based on a profit margin reported

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3 NER, clause 6.2.5(d).

4 CitiPower, *Revised Regulatory Proposal 2011 to 2015,* 21 July 2010, p. 433; Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p. 434.

by Norfolk's Electrical and Communications Division. CitiPower and Powercor also considered that the AER's calculation to incorporate a profit margin within its labour rate was incorrect

- contract rates—that the AER should allow alternative control services prices to increase over the forthcoming regulatory control period in line with increasing costs due to the AMI rollout
- labour rates for line workers—that the AER should reconsider the labour rates used to calculate draft decision prices in light of information taken from a Hays salary survey, daily work hours, public holidays, non-chargeable time and other DNSP labour rates around the NEM
- times required for activities—that the AER should reconsider the draft decision on times taken to perform services based on CitiPower's and Powercor's own surveys and reports on the times and tasks taken in performing services in their networks.

CitiPower and Powercor therefore made revisions to the alternative control services model used by the AER in setting draft decision charges, reflecting their positions on the input costs and times taken to provide fee based alternative control services.[5]

CitiPower and Powercor provided separate price paths for 2012–15 for their reconnection, disconnection and special read services and all other fee based alternative control services, as set out in table 20.9.

CitiPower's revised regulatory proposal stated that it had decided not to provide its proposed fault level compliance service due to the AER's decision to classify this service as a fee based alternative control service.[6] CitiPower and Powercor both provided proposed prices for re-test of types 5 and 6 meters and reserve feeder services, as requested in the draft decision.[7]

For quoted services, CitiPower and Powercor proposed revised hourly labour charge out rates for line workers, design/survey workers and administration workers, as set out in table 20.1.

[5] CitiPower, *Revised regulatory proposal*, Appendix 19; Powercor, *Revised regulatory proposal,* Appendix 19.

[6] The AER's consideration of this classification issue is provided in chapter 2.

[7] CitiPower, *Revised regulatory proposal*, p. 444; Powercor, *Revised regulatory proposal*, p. 445.

Table 20.1 CitiPower and Powercor revised regulatory proposal—hourly charge out rates for quoted services ($, 2010), excluding GST

	CitiPower	Powercor
General line worker—business hours	115.14	112.11
General line worker—after hours	126.61	123.28
Design/survey—business hours	123.56	120.31
Design/survey—after hours	139.16	135.50
Administration	47.85	45.34

Source: CitiPower, *Revised regulatory proposal*, p. 447; Powercor, *Revised regulatory proposal*, p. 448.

CitiPower and Powercor also amended the draft decision approved charges to incorporate their own proposed cost escalators.

20.3.2 Jemena Electricity Networks (JEN)

Charges submitted in JEN's revised regulatory proposal for fee based alternative control services largely reflected the AER's draft decision on the inputs of labour and times. However, JEN's revised regulatory proposal stated that the incorporation of elements of the AER’s draft decision should not be taken as JEN necessarily agreeing with or endorsing the AER’s or Impaq’s conclusions on the underlying or efficient costs of providing alternative control services.[8]

JEN raised issues regarding the following elements of the AER's draft decision on alternative control services:

- profit margins
- hourly rates for line workers—non chargeable time
- after hours rates for line workers
- scheduler hourly rates
- times taken to perform back office functions, wasted service vehicle visits
- contract rates for meter equipment test services
- tax liabilities for routine connection services
- reserve feeder charges
- temporary supply services.[9]

[8] JEN, *Revised Regulatory Proposal 2011–15*, 20 July 2010, p. 325.
[9] ibid., pp. 327–347.

In addition, JEN adjusted its revised regulatory proposal charges to correct for some errors it submitted the AER made in interpreting the times proposed by JEN. JEN's revised regulatory proposal charges also incorporated its own proposed cost escalators.

20.3.3 SP AusNet

SP AusNet's revised regulatory proposal largely accepted the AER’s draft decision for fee based alternative control services. However, SP AusNet raised issues regarding the following elements of the draft decision:

- the inclusion of Access Economics’ revised labour escalators
- the 38 per cent reduction in SP AusNet's proposed fee for Multi Phase Overhead—CT connected meter—After hours
- the 6 per cent reduction in SP AusNet's proposed fee for Overhead supply—Coincident Disconnection (Truck visit)—After hours.[10]

SP AusNet's revised regulatory proposal included further information on its proposed fee for the 'after hours truck by appointment' service, as requested in the draft decision.[11]

SP AusNet accepted the draft decision regarding its proposed quoted services fees.

SP AusNet also accepted the draft decision to escalate its quoted services labour rates by the outsourced labour escalation rate approved by the AER for standard control services. However SP AusNet's proposed charges in its revised regulatory proposal incorporated its own revised cost escalators.[12]

20.3.4 United Energy

United Energy's revised regulatory proposal largely accepted the AER's draft decision on its fee based alternative control services charges for 2011. However, United Energy raised an issue regarding the AER's rejection of its proposed charges for meter data services for customers consuming more than 160MWh per annum.[13]

United Energy submitted revised proposed charges for the services which the AER identified as being arbitrarily inflated above the winning bidder prices, following further negotiation with its winning bidder.[14]

20.4 Submissions

The AER received one submission in response to its draft decision for alternative control services, from the Property Council of Australia. The submission discussed CitiPower's initial proposal to provide a 'fault level compliance service' as a standard control service. This service relates to the connection of embedded generators.

[10] SP AusNet, *Electricity Distribution Price Review, Revised Regulatory Proposal*, July 2010, p. 388.
[11] ibid., p. 389.
[12] ibid., attachment *'SP AusNet - ACS prices - SP AusNet RevisedV1.xls.'*
[13] United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, July 2010, p. 339.
[14] ibid., p. 339.

The Property Council of Australia expressed dissatisfaction with the classification of the fault level compliance service as an alternative control service in the draft decision, and CitiPower's decision not to provide the service. The AER has considered the Property Council of Australia's submission in its final decision on service classification, set out in chapter 2.

The AER did not receive any other submissions relating to its decisions, or the Victorian DNSPs' revised proposals, on alternative control services prices.

20.5 Consultant review

The AER engaged Impaq to reconsider its initial report in light of the issues regarding alternative control services raised by CitiPower, Powercor and JEN in their revised regulatory proposals. In particular, Impaq was engaged to review issues raised in relation to:

- hourly labour charge out rates for line workers
- contract rate increases during 2012–15 due to the AMI rollout
- times taken to perform certain services.

Impaq provided an addendum to its initial report setting out the issues raised and its responses, which is available on the AER's website.[15] Impaq's advice in response to these issues is detailed in the following section.

20.6 Issues and AER considerations

In making this final decision on the form of control for alternative control services, the AER has applied the form of control as set out in its Framework and approach paper, being:

- for fee based alternative control services, a price cap for 2011 prices and a CPI—X price path for 2012–15
- for quoted alternative control services, a cap on the hourly labour rates for 2011 and a CPI—X price path for 2012–15.

The AER has had regard to the factors set out in clause 6.2.5(d) of the NER in deciding on the form of control, as was detailed in the draft decision. The Victorian DNSPs' revised regulatory proposals accepted the AER's draft decision on the form of control and accordingly the AER reaffirms its draft decision and its reasons as stated in the draft decision on pages 849 to 851.[16]

The AER has also had regard to the national electricity objective in s.7 of the National Electricity Law (NEL), and additionally, the revenue and pricing principles in s.7A of

15 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1.3, 26 October 2010.

16 AER, *draft decision*, pp. 849–851.

the NEL when determining prices and labour rates for alternative control services.[17] In terms of the latter, the AER:

- reviewed the cost inputs affecting prices and labour rates against a range of industry benchmarks across the NEM, investigating the average times each service would require and applying the highest point in the range of labour rates and times.[18] Accordingly, the AER considers it is allowing the Victorian DNSPs a reasonable opportunity to recover the efficient underlying costs of providing each service, as required by clause 7A(2) of the NEL.

- built a 3 per cent margin above overheads into the final approved labour rates and prices, reflecting the AER's view that, while data limitations prevent a precise calculation of past efficiencies, some margin is necessary to reward the DNSPs for past efficiencies gained in providing alternative control services. These efficiencies are to be returned to customers in the 2016–20 regulatory control period.[19]

- set prices at the underlying costs, plus a margin above overheads for past efficiencies. Therefore, the Victorian DNSPs are provided with an incentive to improve their efficiency over the forthcoming regulatory control period as the gains from any further cost reductions achieved will be retained by the DNSPs during the period. This is consistent with s.7A(3) of the NEL which requires network businesses to be provided with effective incentives to promote economic efficiency in their operation and investment in their networks.

The draft decision sets out the AER's consideration of the proposed prices and hourly labour rates for fee based and quoted alternative control services in the Victorian DNSPs' initial regulatory proposals. These prices and rates are inputs into the form of control. The following section sets out the AER's consideration of the DNSPs' revised regulatory proposals on alternative control services and its final decision. In so doing, and in addition to the matters discussed above, the AER has considered:

- the differing cost build up and top down adjustment methodologies adopted by each Victorian DNSP

- the advice provided by Impaq on the labour, time and materials inputs into service prices, to which an addendum was made to Impaq's May 2010 report following consideration of the revised regulatory proposals

17 Where the AER has, in this chapter, refused to approve an amount (or value) as proposed by a DNSP in its regulatory proposal or revised regulatory proposal, the substitute amount (or value) has, in accordance with clause 6.12.3(f) of the NER, been determined on the basis of the current regulatory proposal and amended from that basis only to the extent necessary to enable it to be approved in accordance with the NER.

18 The AER notes that, by allowing for the highest point in the reasonable range of labour and times, the AER is conservatively allowing for some potential differences between the services provided by each DNSP, and costs that each DNSP faces. The AER has applied the highest point in the range to proposed service prices that fall above the range (and accepted proposed prices that fall within or below the range). This is consistent with the draft decision. AER, D*raft decision*, p. 852.

19 This is discussed in section 20.6.1.2 below.

- margins above overheads incorporated into alternative control services prices, consistent with the AER's approach to outsourced transactions outlined in chapter 6 of the draft and final decisions

- labour and materials escalators applied by the Victorian DNSPs in their revised price paths and the AER's approved escalators set out in appendix K of this final decision.

The AER notes its draft decision position that, with a few exceptions, the highest point in the reasonable benchmark range of labour and times reflects the maximum price that DNSPs should recover from the provision of these services (which includes all overheads and a margin for past efficiencies). While the AER is of the view that it may be appropriate for DNSPs to charge the mid-point or lowest point in the range, it considers that it is conservatively allowing for some potential differences between the services provided by each DNSP, and costs that each DNSP faces, by applying the highest point in the range to proposed service prices that fall above the range (and accepting proposed prices that fall within or below the range).[20] The AER has maintained this draft decision position in determining the 2011 prices and labour rates for fee based and quoted alternative control services in this final decision.

20.6.1 Fee based alternative control services

The following discussion relates to prices for fee based services which will be provided in the 2011–15 regulatory control period, as determined by the service classifications discussed in chapter 2 and set out in appendix B of this final decision, and in table 20.2 below.

[20] AER, *draft decision*, p. 852.

Table 20.2 AER conclusion on service classification of fee based alternative control services for 2011–2015 regulatory control period

Fee based alternative control services
Meter investigation
De-energisation of existing connections
Energisation of existing connections
Special meter reading
Re-test of type 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh
Operation, repair, replacement and maintenance of DNSP public lighting assets*
Fault response - not DNSP fault
Temporary disconnect/reconnect services
Wasted attendance - not DNSP fault
Service truck visits
Reserve feeder
PV installation
Routine connections - customers below 100 amps
Temporary supply services

* This service is considered in chapter 19.
Source: Appendix B of this final decision.

20.6.1.1 CitiPower and Powercor

AER draft decision

The draft decision did not accept CitiPower's and Powercor's proposed prices for fee based alternative control services for 2011 and price paths for 2012–15.[21] Instead, the AER amended elements of CitiPower's and Powercor's cost build up of fee based prices by:

- replacing the labour rates with the highest business and after hours labour rates for line workers recommended by Impaq, adjusted to incorporate a 3 per cent margin above overheads
- replacing the times taken to perform services with the highest times for each task as recommended by Impaq
- replacing the labour and materials escalators with the AER's approved labour and materials escalators for standard control services
- removing an additional profit margin added by CitiPower and Powercor to the cost of providing services.

[21] ibid., pp. 863–864.

Appendix O of the draft decision set out approved prices for fee based alternative control services, and requested that CitiPower and Powercor provide proposed prices for:

- reserve feeder services
- re-test of type 5 and 6 meters
- fault level compliance.[22]

The draft decision also stated that CitiPower's and Powercor's price paths for 2012–15 for fee based alternative control services should incorporate the AER's approved labour and materials escalators for standard control services.[23]

CitiPower's and Powercor's revised regulatory proposals

In response to the draft decision, CitiPower and Powercor submitted new proposed prices for fee based alternative control services, based on their own internal and contract labour rates, times taken to perform services and profit margins, as outlined in section 20.2.1. The following sections outline the issues raised by CitiPower and Powercor and the AER's consideration of those issues.

Consultant review

The AER engaged Impaq to review the advice provided to the AER prior to the draft decision in light of the arguments raised by CitiPower and Powercor. Impaq's responses to the issues raised are detailed in the following section.

Issues and AER considerations

Margins

In making its draft decision on alternative control services margins, the AER had regard to its general approach to outsourced contract margins, set out in chapter 6 of the draft decision. In following the AER's general approach, the draft decision made the following points:[24]

- CitiPower and Powercor had an incentive to enter into a non-arms length contract with their related parties to provide alternative control services, and did not conduct a competitive tendering process prior to the establishment of the contracts—accordingly, following the ‘presumption threshold’ set out in chapter 6, the AER should not *presume* the contract price reflects efficient costs, but rather, needs to assess whether the related parties’ underlying costs and the margins in the contract reflect efficient and prudent costs
- The AER considered whether the contract costs reflected the costs that would be incurred by an efficient operator by benchmarking the labour charge out rates and times taken to perform services against industry standards, based on Impaq's advice. The AER adjusted the labour rates and times taken to perform services to reflect industry benchmarks.

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22 ibid., pp. 863–864.
23 ibid., p. 864.
24 AER, *draft decision*, pp. 859–861.

- The AER noted that the draft decision approved labour charge out rates already incorporate corporate overheads, and as such the DNSPs did not require a margin to cover these costs.

- Additionally, alternative control services consist mainly of labour, and as most of the DNSPs elect to expense the minimal capital costs, the AER considered that there was no margin needed to reflect the required return on capital for alternative control services.

- The AER then considered whether any margin was necessary to reward the contractors for any historical efficiencies they might have realised in the current regulatory control period such as in relation to economies of scale and scope, 'know how' or other efficiencies.

- The AER found that there may be a need to reward efficiencies gained in the provision of alternative control services over 2006–10. As alternative control services are not subject to an efficiency benefit sharing scheme (EBSS), which rewards opex efficiencies gained on standard control services for a six year period, the AER considered that there may be a need for some margin on alternative control services to similarly reward past efficiencies. However, the draft decision stated that these past efficiencies should be passed back to customers in the 2016–20 regulatory control period, and that only new efficiencies gained in alternative control services over the 2011–15 regulatory control period would be retained as margins after 2016.

Accordingly, the draft decision labour rates for CitiPower's and Powercor's fee based alternative control services incorporated a 3 per cent profit margin, above overheads. While the AER elected a 3 per cent profit margin, which was consistent with Impaq's view that profit should be at the lower end of an industry average due to the level of commercial risk associated with the services provided, the AER notes that its reason for providing a margin above overheads differs from Impaq's. Impaq considered that some profit was necessary due to its industry benchmarking of similar services, however the AER considered that this margin was necessary only to allow the DNSPs to retain efficiencies generated over the 2006–10 regulatory period.

In responding to the draft decision, CitiPower and Powercor submitted that the AER should not rely on Impaq's assessment that 3 per cent is an appropriate profit margin for alternative control services. In support of their arguments, CitiPower and Powercor submitted a presentation on 2009–10 financial results for electrical contractor O'Donnell Griffin, stating that it had achieved an EBIT margin of 5.7 per cent in 2009, and 5.8 per cent in 2010.[25] CitiPower's and Powercor's cost build up models for fee based alternative control services incorporated a 5.7 per cent profit margin on top of their revised proposed labour rates, reflecting their view of an appropriate margin.[26]

25 CitiPower, *revised regulatory proposal*, p. 435 and attachment 239, slide 15; Powercor, *revised regulatory proposal*, p. 436 and attachment 239, slide 15.

26 CitiPower, *revised regulatory proposal*, attachment 19; Powercor, *revised regulatory proposal*, attachment 19.

Impaq commented on the additional profit margin information submitted by CitiPower and Powercor, noting again that O'Donnell Griffin and similar electrical contractors have a significantly higher risk profile than the DNSPs due to the fact they must compete to win work.[27]

The AER has considered the information submitted by CitiPower and Powercor, and notes that 5.7 per cent is within the EBIT benchmark range presented by Impaq.[28]

However, the AER maintains its position that the only economic reason to provide the Victorian DNSPs a margin above overheads on alternative control services is to allow them to retain the benefit of historical efficiencies for a period of time, as there is no EBSS for alternative control services. Accordingly, the level of margin above overheads provided (3 per cent) reflects the AER's consideration of the value of these past efficiencies. CitiPower and Powercor did not address the AER's reason for providing a margin on alternative control services.

For standard control services, the calculation of rewards under the EBSS is based on actual opex as compared to forecasts, after adjusting for changes in growth (including sales volumes) and uncontrollable costs. The Victorian DNSPs have indicated that they do not have detailed records of the specific historical costs and volumes of alternative control services, and accordingly the AER is unable to directly calculate the service-specific efficiencies gained over the 2006–10 regulatory period. Consequently, the AER is unable to be as precise in its calculation of the appropriate reward for historical efficiencies on alternative control services as in the EBSS for standard control services. Instead, the AER has estimated a reward that it considers is a reasonable proxy for an EBSS reward, given the data limitations, based on national productivity data for the electricity, gas, water and waste (EGW) sector.

The Australian Bureau of Statistics (ABS) measures and reports on multifactor productivity (MFP) in the market sector industries, which it defines as 'the part of output growth that cannot be attributed to the growth of labour or capital inputs.'[29] Market sector industries is a group defined by the ABS, and includes all industries in the economy except public administration and safety, education and training and healthcare and assistance.[30] EGW is one market sector. In January 2010, the ABS released a data set titled *Experimental estimates of industry multifactor productivity*, which included some estimated data on MFP in the EGW sector over the period 1985–86 to 2008–09. Gross value-added MFP in the EGW sector is estimated as 1 per cent per annum over 1985–86 to 2008–09. However, the data suggests that MFP in the EGW sector has fallen by 3 per cent per annum since 1997–98.[31] This fall in MFP has also been noted by the Productivity Commission, which is currently

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27 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1.3, 26 October 2010, p. 6.

28 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Review of Distributor's proposed Rates in ACS Charges,* revision 1.3, 25 May 2010, p. 38.

29 Australian Bureau of Statistics, *Measures of Australia's Progress 2010, series 3170.0,* released 15 September 2010, glossary. Available at: http://www.abs.gov.au/ausstats/abs@.nsf/Lookup/by%20Subject/1370.0~2010~Main%20Features~Home%20page%20(1) , accessed 6 October 2010, 1:09pm.

30 ABS, *Australian System of National Accounts 2008–09, series 5204.0,* 8 December 2009, pp. 126–127.

31 ABS, *Cat. No. 5260.0.55.002 Experimental Estimates of Industry Multifactor Productivity, Australia: Detailed Productivity Estimates*, January 2010, Table 1.

conducting a review of productivity in the EGW sector to investigate the sources (that is, electricity or gas or water or waste) of the overall decline over the past decade. The Productivity Commission expects to release its findings in June 2011.[32]

There is currently no separate data on EGW sector productivity for Victoria. The AER considers that there may be a number of drivers of falling MFP in the national EGW sector since 1997–98, and notes its finding that the Victorian DNSPs are relatively more efficient than other networks in the NEM, as discussed in appendix H of this final decision. Noting this, and given the data limitations preventing a precise replication of the EBSS for standard control services, the AER considers it is reasonable to assume the Victorian DNSPs have achieved efficiency gains in the provision of alternative control services over 2006–10 that are equal to the long term (1985–86 to 2008–09) MFP growth in the EGW sector reported by the ABS, being 1 per cent per annum. Applying this assumption as a cumulative growth rate over the current regulatory period yields a reward for the forthcoming regulatory control period equal to, on average, 3 per cent per annum.[33]

The AER notes that its reason for providing a margin above overheads on alternative control services does not relate to any level of risk for which the DNSP or an electrical contractor might need to be rewarded. As the shareholders in electrical contractors such as O'Donnell Griffin require them to earn a return on the assets employed in providing the services (which does not apply in relation to alternative control services), the AER considers that 3 per cent is an appropriate margin above overheads to allow a reward for past efficiencies on realised by the Victorian DNSPs in providing alternative control services.

In light of the arguments above, the AER's final decision is to maintain its draft decision that a reasonable margin above overheads for alternative control services is 3 per cent. The AER's approved labour charge out rates, which were used to generate alternative control service prices for CitiPower and Powercor, incorporate a 3 per cent margin above overheads.

In calculating approved prices for CitiPower and Powercor, the AER has removed the 5.7 per cent margin above overheads applied to all costs within the revised proposals, recognising that a 3 per cent margin above overheads is incorporated into the approved labour rates.

The AER notes CitiPower's and Powercor's comments on the AER's calculation of the margins in its draft decision labour rates.[34] The AER has corrected its approach in calculating prices for the final decision.

Labour rates for line workers

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32 Productivity Commission website, http://www.pc.gov.au/research/productivity/electricity-gas-water, accessed 6 October 2010, 2:14pm.

33 The AER has assumed an incremental productivity gain of 1 per cent per annum over 2006–10, where each year's productivity gain is retained for five years, as per the EBSS. Under the EBSS this would result in a reward of 5 per cent in regulatory year one, falling by one per cent each year to one per cent in the final regulatory year. For simplicity in calculating the margin above overheads, the AER has averaged these notional EBSS rewards, resulting in 3 per cent per annum.

34 CitiPower, *revised regulatory proposal*, p. 434–435; Powercor, *revised regulatory proposal*, pp. 435–436.

In its draft decision, the AER, in determining the labour rates for line workers, considered and adopted Impaq's analysis of industry labour rates. Impaq compared the hourly labour rate inputs into prices among the Victorian DNSPs and those in other jurisdictions. Impaq found that, compared to other DNSPs and the 2009 NECA survey of industry charge out rate, CitiPower's and Powercor's charge out rates for business hours line workers were high.[35]

Impaq considered that a reasonable charge out rate for business hours line workers was between $74 and $84 dollars per hour, and for after hours line workers between $84 and $105 per hour ($, 2010).

In response to the draft decision, CitiPower and Powercor stated that Impaq's methodology for determining the range of labour rates was erroneous, and commented specifically on Impaq's advice in relation to the average salary survey, number of available working hours in a day and allowance for non chargeable time.[36] This is discussed further below.

- Average salary survey—CitiPower and Powercor noted that Impaq had regard to salaries advertised in job advertisements across several states on Seek, MyCareer, Jobseeker and CareerOne websites. CitiPower and Powercor stated that advertised salaries cannot give a reliable indication of actual salaries because they are merely offered rates and do not represent the actual rate accepted by the job applicant. They submitted that the actual rate is likely to be higher following negotiations with the employer. CitiPower and Powercor also quoted a salary range from a more specific survey conducted by Hays, being $70 000 to $80 000 for electricians in Victoria.[37] CitiPower and Powercor also disputed the rates quoted by Impaq for similar services provided by ETSA Utilities, Country Energy and EnergyAustralia, noting that the NSW DNSPs' rates are effective as at mid-2010, not 2011, and that the rates may not be comparable.[38] CitiPower and Powercor provided an email from EnergyAustralia stating that its charges for miscellaneous and monopoly services may not be cost reflective.[39]

    - Impaq considered CitiPower's and Powercor's statements, but noted that the quoted Hay's survey did not line up with its own research on advertised salaries, noting Integral Energy's advertised line worker positions with salaries of $56 000 to $70 000 per annum.[40]

    - The AER has considered CitiPower's and Powercor's comments on the rates charged by other DNSPs in the NEM, however considers that the rates recommended by Impaq are based on a reasonable survey of the industry. The AER reviewed ETSA Utilities' Network Tariff and Negotiated Services

35 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Review of Distributor's proposed Rates in ACS Charges*, revision 1.3, 25 May 2010, p. 44–50.

36 CitiPower, *Revised regulatory proposal,* p. 435–438; Powercor*, Revised regulatory proposal,* p. 436–439.

37 CitiPower*, Revised regulatory proposal*, p. 436; Powercor, *Revised regulatory proposal*, p. 437.

38 CitiPower, *Revised regulatory proposal*, p. 437; Powercor, *revised regulatory proposal*, p. 438.

39 EnergyAustralia, *email from Jane Smith to Matthew Serpell*, 5 July 2010, provided to the AER by CitiPower and Powercor at a meeting on 23 August 2010.

40 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1.3, 26 October 2010, p. 6.

Manual (June 2010), and notes that the rates quoted by CitiPower and Powercor as $100 per hour for 'similar services' relate only to a priority appointment, or pre-arranged out of hours appointment for new connection or alteration of existing supply.[41] This is a priority service provided outside business hours. The AER notes that Impaq's recommended hourly charge out rate for line workers after hours is comparable to the ETSA Utilities rate quoted by CitiPower and Powercor, being $102.69 ($, 2010). The AER also notes that ETSA Utilities' Network Tariff and Negotiated Services Manual lists the business hours hourly rate for 'Location of underground mains at the request of a customer' as $85 per hour ($, 2010), which is less than the top of Impaq's recommended range of business hours rates for line workers.[42]

  - The AER also considered the information provided by EnergyAustralia to CitiPower and Powercor, which stated that the hourly rates approved in the AER's distribution determination for EnergyAustralia's monopoly services for 2009–14 '… are not what (EnergyAustralia) would necessarily regard as cost reflective rates for the work carried out.[43] In the absence of any actual evidence that EnergyAustralia's rates for monopoly services are below cost, the AER considers that the approved rates for EnergyAustralia's monopoly services are a reasonable benchmark to use in generating Impaq's recommended rates for line workers. In addition, the AER does not consider the fact that the NSW DNSPs' rates are as at mid-2010 has a material impact on a benchmark comparison for setting 2011 rates for Victorian DNSPs.

  - Consistent with its draft decision, the AER has decided to apply the highest point in the revised range of hourly line worker rates recommended by Impaq, adjusted to include a 3 per cent margin above overheads, which equates to a salary in the bottom end of the range quoted by CitiPower and Powercor.

- Available working hours in a day—CitiPower and Powercor submitted that Impaq's assumptions regarding a 7.5 hour working day and 10 public holidays per annum are not consistent with the CEPU Workplace agreement for 7.2 hour days and 12 public holidays.[44] In response, Impaq revised its recommended hourly labour rates to reflect the CEPU Workplace agreement. The AER agrees with Impaq's revisions to the hourly labour rates.

- Non chargeable time—CitiPower and Powercor pointed out that Impaq's recommended hourly labour rates did not incorporate an allowance for non productive time such as training, work group meetings, OHS and union meetings and jury service.[45] Impaq noted that in its initial hourly labour rates calculation, it assumed that non productive time was included in the overhead rates, however agreed that this may not be correct. Accordingly, Impaq revised its recommended hourly labour rate range to include an additional 10 per cent of non-productive

41 ETSA Utilities, *Network Tariff and Negotiated Services Manual*, June 2010, p. 63.
42 ibid., p. 69.
43 EnergyAustralia, *email from Jane Smith to Matthew Serpell*, 5 July 2010, provided to the AER by CitiPower and Powercor at a meeting on 23 August 2010.
44 CitiPower, *Revised regulatory proposal*, pp. 436–437; Powercor, *Revised regulatory* proposal, p. 438.
45 CitiPower, *revised regulatory proposal*, pp. 436–437; Powercor, *revised regulatory proposal*, p. 438.

time in the low end of the recommended rate range and 15 per cent in the high end of the range. The AER considers that this is an appropriate assumption, noting that the high end of the range is based on the AER's final determination on Public Lighting for EnergyAustralia in April 2010.[46]

In light of the arguments presented by CitiPower and Powercor, and after considering advice provided by Impaq, the AER's final decision is to revise the hourly line worker rates used in calculating CitiPower's and Powercor's draft decision prices.

In calculating CitiPower's and Powercor's approved prices for the final decision, the AER has applied the highest point in the revised range of hourly line worker rates recommended by Impaq, adjusted to include a 3 per cent margin above overheads, as discussed above.

Impaq's revised advice noted that CitiPower's and Powercor's initial proposed labour rates included the prorated cost of a vehicle, where appropriate, however Impaq's initial recommended line worker labour rates for CitiPower and Powercor did not include vehicle costs.[47] Accordingly, as part of its revised advice, Impaq added a vehicle cost to its recommended line worker rates for CitiPower and Powercor, based on hourly vehicle costs approved in the AER's 2009 decision on public lighting charges in Victoria.[48]

In calculating final decision prices for CitiPower's and Powercor's fee based alternative control services, the AER applied Impaq's revised recommended rates incorporating a vehicle, after adjusting the rates to include a 3 per cent margin above overheads. The resulting charges are set out in table 20.3. The rates in table 20.3 can be compared to AER draft decision labour charge out rates of $79.80 and $99.75 ($, 2010) for business and after hours line workers respectively, without the cost of a vehicle.

Table 20.3 AER final decision—hourly charge out rates for line workers for CitiPower and Powercor incorporating a 3 per cent margin above overheads, and vehicle costs ($, 2010)

	CitiPower	Powercor
Business hours - two person crew	112.79	103.04
Business hours - one person crew	116.36	108.76
After hours - two person crew	125.34	114.82
After hours - one person crew	128.91	120.54

Source: Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 18; AER analysis.

46 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 7.
47 ibid., appendix B.
48 ibid., p. 18.

The AER notes that the issues raised by CitiPower and Powercor with regards to non-chargeable time, available working hours and public holidays also affect Impaq's recommended charge out rates for back office workers and schedulers. Consequently, the AER has revised the back office and scheduler charge out rates used in calculating fee based alternative control service prices. In adjusting the rates used in the draft decision, the AER has increased the draft decision rates by 6 per cent, being the effective increase in Impaq's revised line worker rates. The AER notes that, consistent with the draft decision, the AER has accepted CitiPower's and Powercor's proposed back office hourly charge out rates. The AER has, in coming to this view, taken into account the fact that these rates are within the reasonable range recommended by Impaq.

Table 20.4 AER final decision—maximum adjusted hourly charge out rates for back office workers and schedulers, incorporating a 3 per cent margin above overheads ($, 2010)

	Business hours	After hours
Back office worker	60.83	n/a
Scheduler	73.00	80.49

Source: Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 10; AER analysis.

Times taken to perform services

Impaq's analysis of the average times taken to perform fee based alternative control services for the AER's draft decision found that CitiPower's and Powercor's proposed times were significantly overstated for many tasks.[49] Based on its own understanding of the tasks involved in providing alternative control services, Impaq developed a recommended range of times for each labour component for each of the top seven alternative control services. For the draft decision, where CitiPower's and Powercor's proposed times were outside the range developed by Impaq, the AER applied the highest point of Impaq's recommended range of times for the services. For alternative control services for which Impaq did not provide recommended times, the AER determined the appropriate average times based on the DNSPs' description of the tasks and the times recommended by Impaq for similar tasks.[50]

In response to the draft decision, CitiPower and Powercor submitted that the AER should not rely on Impaq's estimates of times taken to perform tasks because they are not supported by actual evidence. CitiPower and Powercor submitted that their own estimates of average times were based on field research.[51] CitiPower and Powercor therefore revised their initial proposal times for some services, however maintained their initial proposed times for others and provided supporting arguments. CitiPower and Powercor specifically responded to Impaq's initial advice in respect of times for

[49] Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Review of Distributor's proposed Rates in ACS Charges,* revision 1.3, 25 May 2010, pp. 51–54.

[50] AER, *draft decision*, p. 858.

[51] CitiPower, *Revised regulatory proposal*, p. 438; Powercor, *Revised regulatory proposal*, p. 439.

CitiPower's travel, back office work for field office visits, service vehicle visits, and meter testing.[52] This is discussed further below.

- CitiPower's travel time between jobs—CitiPower's revised proposed prices incorporated an assumed travel time of 44 minutes for service vehicle visits, which was obtained from a trial undertaken in 2007 by metering operations group technicians recording their travel times to and from jobs.[53] CitiPower did not provide any data to support this particular trial result, however provided some Powercor travel time data from 2006–07 and stated that CitiPower's travel time is likely to be comparable due to traffic congestion in its urban areas.[54]

  - Impaq considered this information, but maintained its initial advice that 45 (or 44) minutes was excessive. Impaq recommended a maximum of 25 minutes for CitiPower's service vehicle visit travel times, up from 20 minutes in its initial advice. Impaq considered Powercor's revised proposed travel time of 40 minutes was reasonable.[55]

  - The AER agrees with Impaq's assessment that travel time in CitiPower's network should be less than Powercor's, despite traffic congestion and parking constraints in CitiPower's area. CitiPower did not provide the outcomes of the trial it conducted on travel times in its own region, and accordingly the AER has relied on Impaq's advice when determining the appropriate times for CitiPower's service truck visit charges. The AER notes that its final decision on CitiPower's field officer travel time also impacts the calculation of CitiPower's prices for new connections and retest of types 5 and 6 meter services.

- Back office times for Field officer visits (special reads)—Impaq's initial advice was that the maximum time necessary for back office work for field officer visits is 1.8 minutes, given the work is fully automated except in exception cases.[56] Having reviewed their proposed time for this service, which was originally 6.6 minutes, CitiPower and Powercor submitted that JEN’s proposed allocation of 2.54 minutes was more appropriate, and allocated it in the build up of their service charges for their revised proposals.[57] Impaq revised its initial advice to accept CitiPower's and Powercor's revised proposed times for back office tasks in Field Officer visits, being 2.54 minutes. The AER considers that this is appropriate.

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52 CitiPower, *Revised regulatory proposal*, pp. 437–443; Powercor, *Revised regulatory proposal*, pp. 439–434.

53 CitiPower, *Revised regulatory proposal*, p. 439.

54 ibid., p. 439. The AER requested the supporting data for CitiPower's travel times, however was advised that the data was unavailable. CitiPower, *Response to AER information request*, 17 September 2010.

55 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 11; Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Review of Distributor's proposed Rates in ACS Charges,* revision 1.3, 25 May 2010, p. 51.

56 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1.3, 26 October 2010, p. 11; Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Review of Distributor's proposed Rates in ACS Charges,* revision 1.3, 25 May 2010, p. 51.

57 CitiPower, *Revised regulatory proposal*, p. 438; Powercor, *Revised regulatory proposal*, p. 439.

- Service vehicle visits—CitiPower and Powercor submitted that Impaq's recommended maximum time of 30 minutes for back office work and 6 minutes for scheduling team work for a service vehicle visit was not supported by any evidence. In their revised proposals, CitiPower and Powercor proposed 48 minutes in total for back office scheduling work, stating that the proposed times are supported through time confirmations within their job tracking software.[58] Impaq accepted this proposal and revised its initial advice on back office times to 48 minutes. This was primarily based on information submitted by JEN, noting that a back office worker undertakes additional checking of the work to be done.[59] The AER considers that Impaq's revised recommended times for these back office and scheduling tasks are reasonable.

- Meter testing—Impaq's initial advice was that the back office and field officer times for meter testing proposed by CitiPower and Powercor were excessive. Impaq stated that it expected back office time should be less than 25 minutes. This was accepted by CitiPower and Powercor in their revised regulatory proposals. Impaq's initial advice was that field officer times for meter testing should be up to 90 minutes for single phase, 102 minutes for multi-phase and 138 minutes for CT connected meters, including travel and testing time.[60] In their revised regulatory proposals, CitiPower and Powercor provided further information on the tasks required in meter testing. Impaq considered the information submitted by both DNSPs, and decided to revise its recommended times for meter testing, as set out in table 20.5.

58 CitiPower, *Revised regulatory proposal*, p. 438; Powercor, *Revised regulatory proposal*, p. 439.

59 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 11.

60 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Review of Distributor's proposed Rates in ACS Charges,* revision 1.3, 25 May 2010, p. 52.

Table 20.5 Field staff meter equipment test times—CitiPower and Powercor revised proposals and Impaq's revised advice (hours)

Service	CitiPower —initial	Powercor —initial	Impaq—initial (max time)	CitiPower —revised	Powercor —revised	Impaq—revised (max time)
Meter equipment test—single phase	2.74	2.68	1.5	2.68	2.61	2.61 (Powercor) 2.36 (CitiPower - due to travel times)
Meter equipment test—single phase - each additional meter	2.01	2.01	0.4	1.1	1.1	1.1
Meter equipment test—multi phase	3.49	3.43	1.7	3.49	3.42	3.42 (Powercor) 3.18 (CitiPower - due to travel times)
Meter equipment test—multi phase - each additional meter	2.76	2.76	0.6	1.95	1.92	1.9
Meter equipment test—CT multi phase	3.41	3.35	2.3	3.41	3.35	3.4

Source: Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 11.

The AER has reviewed the additional information submitted by CitiPower and Powercor on the tasks required for meter testing, and concurs with Impaq's revised recommended times for these services. The AER has used the highest point in Impaq's recommended range of times when calculating fee based alternative control service prices for this final decision.

Following the submission of its revised proposal, Powercor advised AER staff that its model calculating a revised charge for service vehicle visit (after hours) contained an error, resulting in a lower revised proposed charge for the service than should have been the case.[61] The AER has corrected this error in calculating the approved prices for the final decision.

Reserve feeder and retest of type 5 and 6 meters service charges

[61] AER, *Request for information from Powercor*, 30 August 2010.

Due to the AER's draft decision on service classification, the AER requested that CitiPower and Powercor provide proposed prices for reserve feeder, retest of type 5 and 6 meters and fault level compliance service charges over the forthcoming regulatory control period.[62]

CitiPower and Powercor provided proposed fees for reserve feeder and retest of type 5 and 6 meters service as part of their revised regulatory proposals, and stated that they had decided not to provide the fault level compliance service.[63]

For the reserve feeder service, CitiPower and Powercor calculated their proposed prices based on the marginal cost of reinforcement as reported in their 2009 regulatory accounting statements. CitiPower and Powercor assumed that annual operational and maintenance (O&M) costs of the reserve feeder service are approximately 1 per cent of the annual costs of asset replacement and based their proposed prices on this O&M cost. CitiPower's and Powercor's proposed reserve feeder service prices for 2011 are set out in table 20.6.

Table 20.6 CitiPower's and Powercor's reserve feeder charges—current and proposed ($, 2010)

	CitiPower and Powercor – 2010 price ($/kW)	**CitiPower – proposed 2011 price ($/kVA/annum)**	**Powercor – proposed 2011 price ($/kVA/annum)**
Sub-transmission	12.54	1.43	0.78
High voltage	12.54	2.95	3.99
Low voltage	12.54	7.29	14.46

Source: CitiPower, *Revised regulatory proposal*, attachment 19; Powercor, *Revised regulatory proposal*, attachment 19; CitiPower/Powercor, *Victorian Framework and approach – DNSP information request: service classification and control mechanisms*, 12 October 2008, p. 46.

The AER notes that that CitiPower's and Powercor's proposed reserve feeder charges do not include the deep connection costs of providing the service, nor the future asset replacement costs. CitiPower and Powercor stated that deep connection costs are included within the 'incremental costs' paid as part of the upfront customer contribution at the time the reserve feeder is connected, calculated under ESCV Guideline 14. They stated that any existing reserve feeder's future replacement costs are to be funded as standard control network assets, and the new assets are expected to be rolled into the DNSPs' Regulatory Asset Bases (RABs).[64] The AER notes that it is unable to anticipate how future replacement assets will be treated in terms of the DNSPs' RABs, and that this will depend on the regulatory regime at the time, up to 30 years from now. However, the AER considers that CitiPower's and Powercor's approach in calculating reserve feeder charges is reasonable, and is unlikely to result in double recovery of revenue.

[62] AER, *draft decision*, p. 902.
[63] CitiPower, *Revised regulatory proposal*, p. 444; Powercor, *Revised regulatory proposal*, p. 445.
[64] CitiPower and Powercor, *Response to information requested on 6 September 2010,* 9 September 2010.

The AER notes CitiPower's and Powercor's change from a $/kW to a $/kVA/year charge for reserve feeder services in the revised regulatory proposals. A kVA based charge is measured according to the electrical capacity of the additional asset required, rather than on actual energy usage. The AER considers this change is appropriate and will lead to more cost reflective charges.

The AER accepts CitiPower's and Powercor's proposed reserve feeder charges as part of this final decision.

CitiPower and Powercor used their cost build up model to generate proposed prices for retest of types 5 and 6 meters, incorporating their proposed labour rates and times. Proposed 2011 charges for this service are set out in table 20.7.

Table 20.7 CitiPower's and Powercor's proposed 2011 charges for retest of types 5 and 6 meters ($, 2010)

	Business hours	After hours
CitiPower	355.23	389.34
Powercor	337.65	370.08

Source: CitiPower, *Revised regulatory proposal,* attachment 19; Powercor, *Revised regulatory proposal,* attachment 19.

The AER considers the times proposed by CitiPower and Powercor for retest of types 5 and 6 meters are reasonable, considering other similar meter test times which were reviewed by Impaq.

However, consistent with its decision for other fee based services, the AER considers that the labour rates for back-office and line workers incorporated within CitiPower's and Powercor's proposed prices for retest of types 5 and 6 meters are unreasonably overstated.

The AER has replaced the proposed labour rates with the rates it approved for other fee based services, as set out in tables 20.3 and 20.4. The AER has also amended the travel time for CitiPower to be consistent with Impaq's advice on CitiPower's field officer travel times, as discussed above.

Temporary supply services

Temporary supply services are typically required where construction work requires a temporary connection to a new site. Often the service charge incorporates coincident disconnection or abolishment once construction work on the site is complete, and then a separate standard new connection charge is paid to permanently connect the new premises.

CitiPower's and Powercor's initial regulatory proposals did not propose prices or labour rates for temporary supply services. Their revised regulatory proposals incorrectly stated that the draft decision classified temporary supply services as quoted alternative control services. The draft decision classification for these services was fee based alternative control services.

Subsequent to their revised regulatory proposals, CitiPower and Powercor indicated that they intend to charge standard new connection charges for the connection of temporary supplies, and then an additional new connection charge for the permanent connection of the new site.[65] Accordingly, CitiPower and Powercor did not propose separate charges for temporary supply services.

In reviewing CitiPower's and Powercor's proposals to charge their new connections prices for temporary supply services, the AER has considered the price differential between the final decision prices for 'new connections' and 'temporary supply' services for JEN, which was generated using Impaq's recommended times and labour rates. As the approved fee for JEN's 'temporary supply' service falls between JEN's approved prices for 'routine new connections' of single phase and multi phase customers, the AER considers it is appropriate that CitiPower and Powercor charge their approved 'new connection' charge for the 'temporary supply' services. Table 20.8 sets out JEN's, CitiPower's and Powercor's approved prices for temporary supply and routine new connection services for comparison.

Table 20.8 AER final decision—JEN, CitiPower and Powercor temporary supply and routine new connections prices, where the DNSPs are responsible for metering—business hours ($, 2010)

	CitiPower	Powercor	JEN
Routine new connection—single phase	357.66	326.29	397.11
Routine new connection—multi phase, direct connected	441.67	425.99	487.33
Temporary supply—coincident abolishment	357.66	326.29	420.11

Source: CitiPower, *Revised regulatory proposal*, attachment 19; Powercor, *Revised regulatory proposal*, attachment 19; JEN, *Revised regulatory proposal*, ACS cost build up model; AER analysis.

Price paths and contract rates

The draft decision rejected CitiPower's and Powercor's proposed price paths for alternative control services, requesting that the DNSPs propose X factors in accordance with the draft decision on the form of control.

The draft decision also stated that CitiPower's and Powercor's proposed escalation of reconnection, disconnection and special meter read services over the forthcoming regulatory control period was significant and had not been adequately justified.

65 CitiPower and Powercor, *Response to information request on 6 September 2010*, 7 September 2010.

The proposed increase in these service prices was between 77 and 94 per cent by 2015, due to significant increases in external contractor rates resulting from average service cost increases in 2012 and 2013 because of the AMI rollout.[66]

CitiPower's and Powercor's revised regulatory proposals included a copy of a CHED Services Conditions of Contract document, as well as a presentation by their alternative control service provider in October 2009.[67] In a meeting with the AER and Impaq, CitiPower and Powercor explained that the service provider's presentation was made during the negotiation phase of the service contract for 2010.[68] CitiPower's and Powercor's revised regulatory proposals included proposed X factors for 'connections' services (including reconnection, disconnection, and special reads services) and separate X factors for all other fee based alternative control services. The proposed X factors were applied in CitiPower's and Powercor's cost build up models as a weighted average, varying between years and services according to the forecast volumes.[69] Table 20.9 sets out CitiPower's and Powercor's proposed X factors.

Table 20.9 CitiPower's and Powercor's proposed X factors (per cent)

	2012	2013	2014	2015
CitiPower - fee based 'connection' services - including reconnection, disconnection, and special reads services	–37.4	–27.2	–0.3	–0.2
CitiPower - other fee based services	–0.9	–1.9	–2.6	–1.6
Powercor - fee based 'connection' services - including reconnection, disconnection, and special reads services	–41.6	–29.4	–0.2	–0.1
Powercor - other fee based services	–1.6	–1.9	–2.0	–0.8

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.

Source: CitiPower, *Revised regulatory proposal*, p. 444; Powercor, *Revised regulatory proposal*, p. 445.

Impaq considered the material provided by CitiPower and Powercor to support their proposed contract rate increase for 2012–13. Noting that, for CitiPower, the resulting prices for 2013 are lower than current (2010) prices for these services, Impaq considered that the lost efficiencies resulting from fewer services being provided due to the AMI rollout would likely increase the average cost of providing reconnections, disconnections and special reads over 2012–13.

Impaq commented that Powercor's proposed 2013 prices for reconnections, disconnections and special reads was higher than current (2010) prices, however noted that it was less than the 100 per cent increase implied by the underlying contract

[66] AER, *draft decision*, pp. 862–863.

[67] CitiPower, *Revised regulatory proposal*, p. 435 and attachments 231 and 239; Powercor, *Revised regulatory proposal*, p. 436 and attachments 231 and 239.

[68] AER, *file note of meeting with CitiPower, Powercor and Impaq Consulting*, 23 August 2010.

[69] CitiPower, *Revised regulatory proposal*, p. 444 and attachment 19; Powercor, *Revised regulatory proposal*, p. 445 and attachment 19.

rate escalation.[70] Overall, Impaq considered CitiPower's and Powercor's proposed price escalation for these services over 2012–15 to be reasonable.[71]

Table 20.10 sets out CitiPower's and Powercor's proposed price increases over the forthcoming regulatory control period, including their own proposed cost escalators.

Table 20.10 CitiPower's and Powercor's proposed price increases over 2011–15 (per cent)

Service	CitiPower	Powercor
Meter accuracy tests; meter investigations tests - single phase meters; service truck visits - business hours	10	9
Meter accuracy tests; meter investigations test - multi phase meters; service truck visit - after hours; wasted service truck visit	11	9–10
Reconnections (including customer transfer) - business hours	65	75
Reconnections (including customer transfer) - after hours	92	94
Reconnections (same day) - business hours	72	84
Disconnection (includes disconnection for non payment) - business hours	66	77
Special reads/customer transfers - business hours	83	89
Solar PV connections	9	8
New connections	5–8	3–7

Source: CitiPower, *Revised regulatory proposal*, attachment 19; Powercor, *Revised regulatory proposal*, attachment 19.

The AER's analysis found that CitiPower's 2015 prices for reconnections, disconnections and special reads are proposed to be lower than current (2010) prices. Tables 20.11 and 20.12 set out CitiPower's and Powercor's current (2010), and proposed 2011 and 2015 prices for reconnections, disconnections and special read services.

70 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, pp. 4–5.

71 ibid.

Table 20.11 CitiPower—current and proposed prices for reconnections, disconnections and special reads ($, 2010)

	2010 current	2011 proposed	2015 proposed
Reconnections (including customer transfer)—business hours	23.82	13.27	21.96
Reconnections (including customer transfer)—after hours	155.77	56.62	108.66
Reconnections (same day)—business hours	(not currently provided)	16.63	28.68
Disconnections (includes disconnection for non-payment)—business hours only	59.91	13.45	22.31
Special reads/customer transfer—business hours only	23.82	10.29	18.81

Note: These are manual service prices. The AMI rollout will result in these types of services being provided remotely, which will result in substantially lower charges. The AER is considering the Victorian DNSPs' proposals for AMI remote services charges for 2011 concurrently with this decision, as noted in the introduction to this chapter.

Source: CitiPower, *Revised regulatory proposal*, attachment 19.

Table 20.12 Powercor—current and proposed prices for reconnections, disconnections and special reads ($, 2010)

	2010 current	2011 proposed	2015 proposed
Reconnections (including customer transfer)—business hours	19.97	18.71	32.84
Reconnections (including customer transfer)—after hours	144.97	77.67	150.76
Reconnections (same day)—business hours	19.97	29.58	54.57
Disconnections (includes disconnection for non-payment)—business hours only	19.97	19.80	35.02
Special reads/customer transfer—business hours only	19.97	15.70	29.67

Note: These are manual service prices. The AMI rollout will result in these types of services being provided remotely, which will result in substantially lower charges. The AER is considering the Victorian DNSPs' proposals for AMI remote services charges for 2011 concurrently with this decision, as noted in the introduction to this chapter.

Source: Powercor, *Revised regulatory proposal*, attachment 19.

The AER also found that Powercor's proposed 2015 prices for reconnections, disconnections and special reads result in significant increases on current (2010) prices. For example, using Powercor's proposed price path, the 2015 price for Reconnections (same day) service is 73 per cent above the current (2010) charge.

However, as noted in the draft decision, the current (2010) prices for alternative control services are not cost reflective, and in many cases the AER's final decision price for 2011 is lower than the current price. Powercor's current (2010) prices for reconnections, disconnections and special reads are also lower than CitiPower's equivalent current (2010) prices.

The AER acknowledges that there is likely to be some increase in the average cost of providing reconnections, disconnections and special reads over the forthcoming regulatory control period, due to the declining volume of work that will be provided because of the AMI rollout.

The AER also notes that these services will be provided remotely to all customers with an AMI meter once the AMI communications systems are sufficiently rolled out and will be at a significantly lower cost than the traditional manual services. The AER is conducting a review of CitiPower's and Powercor's proposed remote services prices concurrently with this final decision but under a separate legislative instrument.[72] The AER expects to release its final decision on remote services prices by December 2010 and anticipates that these services will become available progressively from 2011.

The AER considers that CitiPower's and Powercor's proposed contract rate escalation is supported by evidence of rate increases from their service provider, and that the escalations applied are likely to be reasonable considering the declining number of services which will be provided and increasing average costs. Accordingly, the AER accepts CitiPower's and Powercor's proposed escalation of contractor rates over 2011–15.

For the same reasons set out in appendix K for rejecting CitiPower's and Powercor's proposed cost escalators for standard control services, the AER rejects CitiPower's and Powercor's proposed cost escalators used within their fee based alternative control services price paths for 2012–15.

Consistent with its draft decision, the AER has decided to apply its approved cost escalators, considered in chapter 8 and appendix K of this final decision to the appropriate labour and input cost elements of CitiPower's and Powercor's X factors for alternative control services. The resulting approved X factors for CitiPower and Powercor, to be applied over 2012–15 in the annual price approval process are set out in table 20.13.

[72] Essential Services Commission of Victoria (ESCV), *Electricity Industry Guideline No. 14—Provision of Services by Electricity Distributors—Issue* 1, April 2004.

Table 20.13 AER final decision—approved X factors for fee based alternative control services

	2012	2013	2014	2015
CitiPower - fee based 'connection' services - including reconnection, disconnection, and special reads services	–37.4	–27.2	–0.3	–0.2
CitiPower - other fee based services	–0.5	–1.8	–3.3	–1.8
Powercor - fee based 'connection' services - including reconnection, disconnection, and special reads services	–41.6	–29.4	–0.2	–0.1
Powercor - other fee based services	–1.2	–1.8	–2.7	–1.0

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.
Source: CitiPower and Powercor, *response to information requested 12 October 2010*, 15 October 2010.

AER conclusion

The AER rejects CitiPower's and Powercor's revised proposed 2011 prices for fee based alternative control services, aside from its proposed reserve feeder service fee. The AER accepts CitiPower's and Powercor's proposed prices for reserve feeder services for 2011–15.

In approving all other fee based alternative control service 2011 prices for this final decision, the AER has:

- applied the highest point of the range of revised labour rates recommended by Impaq, adjusted to incorporate vehicle costs and a 3 per cent margin above overheads, as set out in tables 20.3 and 20.4
- revised the times taken to perform tasks consistent with Impaq's revised advice.

The AER accepts CitiPower's and Powercor's escalation of their service provider's contract rate which affects the X factors for reconnections, disconnections and special reads. However, the AER rejects CitiPower's and Powercor's proposed X factors for fee based alternative control services, and instead approves the X factors set out in table 20.13 which incorporate the AER's final decision on cost escalators.

20.6.1.2 Jemena Electricity Networks (JEN)

AER draft decision

The draft decision rejected JEN's proposed fee based alternative control service prices for 2011, including proposed prices for routine new connections.

For the draft decision, the AER made the following adjustments to JEN's proposed fee based alternative control service prices for 2011, using JEN's cost build up model:

- applied the high point of business and after hours line worker hourly charge out rates recommended by Impaq, after reducing the rate to account for a 3 per cent margin above overheads

- applied the midpoint between Impaq's recommended back office rate and line worker rate for JEN's scheduling team rates

- where the proposed times were found to be above the reasonable range recommended by Impaq, the AER applied the high point of the times taken to perform alternative control services

- applied the same labour and materials escalators it applied to JEN's standard control services to equate the approved prices to 2011 dollars.[73]

The AER also rejected JEN's proposed prices for manual meter equipment tests as it considered the Formway contract rate had not been appropriately justified.

The draft decision requested that JEN submit proposed prices for new connections services where JEN is not the responsible person for metering.

Appendix O of the draft decision set out approved prices for fee based alternative control services.

The draft decision also stated that JEN's price path for 2012–15 for fee based alternative control services should incorporate the AER's approved labour and materials escalators for standard control services.[74]

JEN's revised regulatory proposal

As noted in section 20.3.2 above, JEN's revised regulatory proposal charges for fee based alternative control services largely reflected the AER's draft decision on the inputs of labour and times.

However, JEN noted that it did not necessarily agree with or endorse the AER's or Impaq's conclusions on the underlying or efficient costs of providing alternative control services.[75] JEN raised a number of issues with Impaq's assessment, which are discussed below.

JEN's cost build up model corrected what it perceived as AER errors in interpreting the times put forward in JEN's initial proposal model. In addition, JEN used its own revised labour and materials escalators to calculate X factors.[76]

Consultant review

The AER engaged Impaq to review the advice provided for the draft decision in light of the arguments raised by JEN. Impaq's responses to the issues raised are set out in the following section.

Issues and AER considerations

Margins

JEN's revised regulatory proposal stated that it is exposed to the same market conditions as other businesses in similar industries, noting that certain alternative

[73] AER, *draft decision*, p. 873.
[74] ibid.
[75] JEN, *Revised regulatory proposal*, p. 325.
[76] ibid., p. 327.

control services are affected by economic growth fluctuations.[77] JEN did not address the AER's reason for providing a margin on alternative control services, being to allow the retention of efficiency gains realised over 2006–10 for five years, given there is no EBSS for alternative control services. The AER notes that this reasoning does not relate to any risk that the DNSP or a similar electrical business might encounter.

The AER notes the discussion above in section 20.6.1.1 relating to CitiPower's and Powercor's revised proposed margins for alternative control services and has adopted the same view in respect of JEN. Noting the limited data on actual efficiency gains in alternative control services, as noted in section 20.6.1.1, the AER has assumed that JEN has achieved efficiency gains in the provision of alternative control services over 2006–10 that are equal to the long term (1985–86 to 2008–09) estimated MFP growth in the EGW sector, being 1 per cent per annum. Applying this assumption as a proxy for the EBSS for standard control services over the current regulatory period yields an average reward for the forthcoming regulatory control period equal to 3 per cent per annum.[78] The AER notes that as other private contractors are funding returns on assets, risk and intangible assets out of their profit margins, the AER considers that 3 per cent is an appropriate margin to provide a reward for past efficiencies on monopoly provided alternative control services.

The AER's final decision is to maintain its draft position that a reasonable margin above overheads for alternative control services is 3 per cent, which is reflective of a proxy-EBSS reward for productivity gains estimated using long-run MFP data. The AER's approved labour charge out rates, which were used to generate JEN's prices, incorporates a 3 per cent margin above overheads.

Hourly labour rates

The draft decision stated that the AER considered JEN's initial proposed hourly labour rates for line and back office workers were considerably higher than industry standards, based on advice provided by Impaq.

As such, the AER considered that it was reasonable to apply the highest point of Impaq's recommended range of labour rates for each of the services, adjusted to include a 3 per cent margin above overheads.[79]

JEN's revised regulatory proposal stated that Impaq's analysis of charge out rates had only taken into consideration available hours, and did not consider the impact of non-productive activities. It noted that Impaq had not converted available hours into chargeable hours and as a result estimated that the actual chargeable hours are about 10 per cent lower than the available hours recommended by Impaq.[80]

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77 JEN, *Revised regulatory proposal*, p. 330.

78 The AER has assumed an incremental productivity gain of 1 per cent per annum over 2006–10, where each year's productivity gain is retained for five years, as per the EBSS. Under the EBSS this would result in a reward of 5 per cent in regulatory year one, falling by one per cent each year to one per cent in the final regulatory year. For simplicity in calculating the margin above overheads, the AER has averaged these notional EBSS rewards, resulting in 3 per cent per annum.

79 AER *draft decision*, pp. 872–873.

80 JEN, *Revised regulatory proposal*, p. 330.

As discussed in section 20.6.1.2 for CitiPower and Powercor, Impaq has revised its recommended hourly rates for line workers to include up to 15 per cent of additional non productive time in the high case line worker charge out rate. The AER has also increased its approved hourly charge out rates for back office workers and schedulers in line with the increase to line worker rates, as set out in table 20.14. These rates have been applied by the AER in approving JEN's fee based alternative control services prices for 2011.

Table 20.14 AER final decision—maximum adjusted hourly charge out rates for JEN including a 3 per cent margin above overheads ($, 2010)

	Business hours	After hours
JEN—line worker	85.17	100.14
Back office worker	60.83	n/a
Scheduler	73.00	80.49

Source: Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, pp. 12–13; AER analysis.

JEN's revised proposal stated that Impaq had not adequately considered the costs of provision of out of hours services. JEN referred to its enterprise bargaining agreement (EBA) which stipulates that JEN is required to pay a line worker for a minimum of four hours when called out to perform a job after hours, regardless of the time taken to perform the task.[81]

Impaq considered JEN's proposal with regards to the EBA, however maintained its initial advice on after hours rates. Impaq noted that most after hours alternative control services are scheduled, and that services could be performed on an afternoon shift, or within 2 hours of overtime, as allowed for in the EBA. In these cases, no 'call out' of JEN's workers would be required, and therefore JEN would not be required to pay its workers for four hours of overtime.[82] The AER agrees with Impaq's view that after hours rates should not be charged as call out rates.

JEN's revised proposal stated that Impaq's assumption that an appropriate rate for a scheduler is half way between a back office worker and a line worker is incorrect. JEN submitted that a scheduler is often a former line worker.[83]

However, as Impaq pointed out, JEN's initial proposed rate for a scheduler of $65.33 ($, 2010), is approximately half way between JEN's initial proposed rates for back office and line workers, being $58.58 and $72.00 per hour ($, 2010) respectively.[84] Accordingly, the AER rejects JEN's proposal for an increase in the scheduler hourly rate used to calculate alternative control services prices.

Tax liabilities for routine connection services

81 ibid., p. 331.
82 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 12.
83 JEN, *Revised regulatory proposal*, p. 332.
84 Note that JEN's proposed rates quoted here do not include overheads.

JEN's revised proposal noted that under the AER's approach to classification of routine connection services, there will not be a regulatory asset base to which the assets created by a routine connection can be added.

JEN submitted that, given the nature of routine connection assets, it would have no choice but to capitalise the costs of creating the assets for tax purposes, thereby incurring a tax liability for income received from routine connection services.[85]

During the AER's review, JEN indicated that under Division 40 of the Income Tax Assessment Act 1997, it is required to capitalise tangible assets greater than $100 and add them to its low value pool (less than $1000), to be depreciated within the terms of that pool for taxation purposes.[86]

In order to recover the cost of this tax liability, JEN proposed a mark up of 7 per cent be applied to its routine new connections prices, based on some analysis of the likely tax liability. JEN's revised alternative control service model for routine connections prices included a placeholder for such a mark up.[87]

The AER has considered this issue as part of its final decision on JEN's alternative control service prices. The AER notes that the mark up is a result of the tax liability incurred due to the capitalisation of JEN's routine connection assets, which is unavoidable under the relevant tax legislation. The AER also notes that this is consistent with tax liabilities for standard control services. The AER therefore accepts JEN’s proposal for a 7 per cent mark up on routine connections services.

The AER notes that the tax liability included in final decision prices for routine connections was calculated in JEN's model using its proposed WACC. However the AER has input its final decision on the cost of capital (WACC) in place of that proposed by JEN.

Times taken to perform services

Impaq's analysis of the average times taken to perform fee based alternative control services for the AER's draft decision found that JEN's proposed times for tasks were overstated.[88]

As noted above, Impaq developed a range of times in which various components of each service could be expected to be performed. For the draft decision, where JEN’s proposed times were outside the range developed by Impaq, the AER applied the highest point of Impaq’s recommended range of times for the services. For alternative control services which Impaq did not provide recommended times, the AER determined the appropriate average times based on the DNSPs' description of the tasks and the times recommended by Impaq for similar tasks.[89]

In its revised regulatory proposal JEN provided additional information in relation to back office functions for new connections, temporary supply services, service vehicle

85 JEN, *Revised regulatory proposal*, p. 339.
86 JEN, *response to information requested on 6 August 2010*, 16 August 2010.
87 ibid.
88 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Review of Distributor's proposed Rates in ACS Charges,* revision 1.3, 25 May 2010, pp. 51–54.
89 AER, *draft decision*, p. 870.

visits, manual re-energisation and de-energisation services, as well as information on field line work in relation to wasted service vehicle visits.

For back office functions for new connections, temporary supply services and service vehicle visits, JEN noted that not all service orders are completed without complications or additional issues arising. JEN submitted that on average, a back office worker is expected to take 12 to 15 calls daily with time spent on each call varying between 1 to 20 minutes and in some cases longer depending on the inquiry.[90] After considering this additional information, Impaq revised its recommended time for back office workers performing tasks for the following services:

- service vehicle visits
- wasted service vehicle visits
- temporary supply/coincident abolishment services
- new connections services.[91]

The AER agrees with Impaq's revised times for these back office functions, noting that the impact of this revised time is a change in the highest point of Impaq's recommended range from 36 minutes to 48 minutes.

For back office functions in relation to manual re-energisation and de-energisation services, JEN noted that the functions are performed by the same back office staff however JEN apportions a greater time for de-energisation, to reflect the extra time required for manual intervention to, for example, ensure life support customers are not disconnected.[92]

Impaq accepted this reasoning and adjusted the highest point in its recommended range of times for back office tasks relating to de-energisation services.[93]

For field line worker time in relation to wasted service vehicle visits, JEN advised that service vehicle visits are booked in one hour blocks for appointments.

JEN submitted that if the customer is not ready for the scheduled work upon arrival of the vehicle, the service crew cannot be productively employed elsewhere. JEN stated that the crew would have already spent time travelling to the work site and estimated that remaining time would be about 30 minutes. JEN noted that given the short duration of each service vehicle visit there is insufficient time to schedule further jobs.[94]

[90] JEN, *Revised regulatory proposal*, p. 333.
[91] Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 14.
[92] JEN, *Revised regulatory proposal*, p. 335.
[93] Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 14.
[94] JEN, *Revised regulatory proposal*, p. 335.

Impaq accepted JEN's arguments to apply the same times for wasted service vehicle visits as ordinary service vehicle visits.[95] The AER agrees that this change to Impaq's recommended times is reasonable.

Contract rates for meter equipment test services

The draft decision rejected JEN's proposed prices for meter equipment tests due to its Formway contract rate (which the AER found to be significantly higher than equivalent rates when comparing the services among the Victorian DNSPs).

In response to the draft decision, JEN provided more information on the Formway rate, including an estimated breakdown of the times taken by Formway in carrying out the meter equipment tests, as well as information on the services provided and the arrangements under which Formway was selected as the service provider.[96]

JEN also clarified its proposed meter equipment tests by changing the names of the services to match the equivalent services provided by the other Victorian DNSPs.

The AER considered the additional information submitted by JEN on its Formway contract rates, and found that the estimated times for conducting the testing were greater than Impaq's recommended times. However, due to a lower estimated hourly charge out rate, the proposed price for JEN's meter equipment tests were lower than the resulting cost build ups for CitiPower and Powercor.

Accordingly, the AER accepts JEN's proposed prices for meter equipment tests, except for the back office rate used, which was above the reasonable range recommended by Impaq. In calculating prices for JEN's fee based services, the AER has input the back office rate in table 20.14, being the high point of Impaq's recommended range, adjusted to include a 3 per cent margin above overheads.

Reserve feeder service charges

In its response to the draft decision, JEN provided further information on its proposed charges for its reserve feeder service, as requested by the AER. JEN provided details on the costs involved in providing the service, and calculated the underlying O&M costs based on its own internal accounts from 2009.[97] While the O&M costs were calculated to be a small fraction of JEN's proposed charge for the service, being \$17.57/kW in 2011 (\$, 2010), JEN stated that additional costs, relating to deep connection assets and future asset replacements are associated with the reserve feeder service. JEN does not charge these deep connection costs as part of the upfront customer contribution charge for reserve feeder customers. JEN did not estimate the historical quantum of deep connection costs likely to be associated with the reserve feeder service, nor the future reserve feeder asset replacement costs, but stated that the difference between its O&M costs and proposed charge of \$17.57 (\$, 2010) is to enable the recovery of these costs.[98] JEN stated that the deep connection assets driven

95 Impaq Consulting, *Victorian Electricity Distribution Determination 2011—Addendum to Review of Distributors Proposed Rates in ACS Charges*, Revision 1. 3, 26 October 2010, p. 14.

96 JEN, *Revised regulatory proposal*, pp. 336–338.

97 ibid., appendix 20.7.

98 JEN indicated that it is unable to estimate these costs, or even identify the relevant deep connection assets, using its current systems and processes. However, JEN stated that it is implementing a new cost allocation methodology and service classification for the forthcoming regulatory control period, which will enable it to collect such data from 1 January 2011. JEN, *response to AER questions*, 15 September 2010.

by the reserve feeder service will have been rolled into its regulatory asset base (RAB) by the beginning of the forthcoming regulatory control period.[99]

The AER notes its discussion on CitiPower's and Powercor's proposed reserve feeder charges, in section 20.6.1.2 above. Unlike JEN, for CitiPower and Powercor customers the deep connection costs of providing Reserve feeder services are paid up front by the customer as part of a capital contribution under ESCV Guideline 14, and accordingly are not included in the $/kVA charge and are not rolled into Citipower's and Powercor's RABs. Also unlike JEN, CitiPower and Powercor do not recover the future asset replacement costs of reserve feeder assets as part of their $/kVA charge/annum, as CitiPower and Powercor expect these will be funded in the future as standard control services and eventually rolled into their RABs.

During the AER's review of its revised regulatory proposal, JEN argued that its reserve feeder service should be classified as a negotiated service.[100] The AER's consideration of the classification of the reserve feeder service is detailed in chapter 2.

The AER notes that its Framework and approach paper allowed the Victorian DNSPs to elect either a bottom up or top down methodology for calculating proposed prices for alternative control services, based on the materiality of the revenues earned from each service. The reserve feeder service affects a very small number of commercial customers and is therefore of low materiality. However, the AER considers that JEN has not sufficiently justified its proposed charge of $17.57/kW per annum ($, 2010) for reserve feeder services. The AER considers that:

- deep connection costs can be accurately calculated at the time the reserve feeder customer connects, and charged as part of the upfront capital contribution calculated under ESCV Guideline 14.[101] This prevents any potential over recovery of costs by JEN, as the costs are calculated and paid for once, rather than averaged out on an ongoing basis. It also means that existing reserve feeder customers, having paid for deep connection costs associated with the service via their kW charges over current and previous regulatory control periods, will now be subject only to the actual O&M costs of providing the service. The AER notes that JEN has indicated that only 3 new reserve feeder customers have been connected on its network in the past 10 years.

- as future replacement reserve feeder assets are likely to be treated as standard control connection assets, and accordingly will be rolled into JEN's RAB, the AER considers there is a high risk of double recovery of costs should JEN charge reserve feeder customers for future replacement costs on an ongoing basis.

Accordingly, the AER rejects JEN's proposed 2011 price for its reserve feeder service.

In calculating the final decision price for JEN's reserve feeder service, the AER has used JEN's estimate of the underlying O&M costs of providing the service, provided

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99 JEN, *response to information requested 8 September 2010*, 15 September 2010.

100 JEN, *response to information requested 8 September 2010*, 15 September 2010; JEN, *response to information requested on 6 August 2010*, 16 August 2010, p. 2.

101 JEN has acknowledged that it could charge the deep connection costs related to its reserve feeder service us part of the upfront customer capital contribution, from 1 January 2011. JEN, *response to information requested 8 September 2010*, 15 September 2010.

as part of its revised regulatory proposal, plus a 3 per cent margin above overheads, reflecting the arguments outlined above.[102] The resulting charge is $4.32/kW ($, 2010).

Classification of temporary supply services

JEN's revised regulatory proposal set out its concerns relating to the AER's draft decision to classify its supply abolishment service as fee based, and not quoted as it proposed.[103]

As part of this final decision, the AER has revised its classification of supply abolishment services from a fee based to a quoted alternative control service, as set out in chapter 2. Accordingly, the AER's approved quoted service hourly charge out rates for JEN will apply to supply abolishment.

Current transformer (CT) connected customer services

JEN's revised regulatory proposal stated that all customers requiring current transformers for metering are connections above 100 amps. The AER's draft decision classified new connections for customers above 100 amps as quoted services, however also approved fixed fees for new connections with current transformers.

For this final decision, the AER has not approved prices for JEN's new connections for CT connected customers, as these services are quoted and subject to the hourly labour charge out rates approved in appendix Q.[104]

Price paths—cost escalators

The draft decision requested that JEN revise its proposed X factors for its fee based services price paths to reflect the AER's draft decision on cost escalators for standard control services. However, JEN's revised regulatory proposal submitted X factors consistent with its own proposed cost escalators for standard control services. The AER's consideration of JEN's proposed cost escalators is set out in appendix K of this final decision.

For the same reasons set out in appendix K for rejecting JEN's proposed cost escalators for standard control services, the AER rejects JEN's proposed cost escalators used within its fee based alternative control services price paths for 2012–15. Instead, the AER approves the cost escalators it has approved for standard control services, listed in appendix K. Applying the cost escalators in appendix K, the AER's final decision on JEN's X factors for each of its fee based alternative control services is set out in appendix Q.

AER conclusion

The AER rejects JEN's revised proposed 2011 prices for fee based alternative control services. In approving JEN's fee based alternative control service 2011 prices for this final decision, the AER has:

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102 JEN, *Revised regulatory proposal*, appendix 20.7.

103 ibid., pp. 340–341.

104 The AER notes that SP AusNet indicated it does frequently use CT meters for customers less than 100 amps, and accordingly needs regulated charges for new connections that are CT connected. SP AusNet, *Response to information requested on 6 August 2010*, 10 August 2010.

- applied the highest point of the range of revised labour rates recommended by Impaq, adjusted to incorporate a 3 per cent margin above overheads, as set out in table 20.14
- revised the times taken to perform tasks consistent with Impaq's revised advice.

The AER's final decision rejects JEN's proposals for increases in the after hours rate and scheduler hourly rate, based on Impaq's advice.

The AER accepts JEN's proposal for a 7 per cent mark up on routine connection services as a result of JEN's capitalisation of routine connection assets.

The AER accepts JEN's proposed Formway contract rate for meter equipment test services.

The AER rejects JEN's proposed reserve feeder charge, and approves a charge of $4.32/kW ($, 2010).

The AER has revised its classification of supply abolishment services from a fee based to a quoted alternative control service. Accordingly, the AER's approved quoted service hourly charge out rate for JEN will apply to supply abolishment.

The AER rejects JEN's proposed X factors for alternative control services, and considers that it is appropriate to apply X factors that incorporate cost escalators that are equal to those approved for standard control services. The AER's final decision on JEN's X factors is set out in appendix Q.

20.6.1.3 SP AusNet

AER draft decision

The draft decision set out the AER's analysis of SP AusNet's proposed 2011 prices for fee based alternative control services, and the methodologies for calculating these prices.

The AER's approach to considering SP AusNet's proposed 2011 prices was benchmarking them against those prices proposed by other DNSPs and against prices generated using hourly labour rates and times taken to perform services advised by Impaq.

The AER analysed SP AusNet's incremental cost model for field officer visits, new connections and service truck visits, finding that the methodologies applied were reasonable. For meter equipment test prices, the AER considered SP AusNet's top down approach to calculation was also reasonable.

The draft decision rejected SP AusNet's proposed 2011 prices for field officer visits, new connections and service vehicle visits, which incorporated SP AusNet's own proposed cost escalators which it also used for standard control services. The approved draft decision prices reflected the AER's view that the cost escalators incorporated within the prices should be equal to the AER's approved cost escalators for standard control services. The AER's reasons for rejecting SP AusNet's cost escalators in the draft decision were set out in chapter 8 and the approved cost escalators were listed in appendix K of the draft decision.

The draft decision approved SP AusNet's proposed price path for fee based services, being:

$P_t \leq P_{t-1} \times (1+CPI) \times (1-X)$, where X = 1 per cent

SP AusNet's revised regulatory proposal

SP AusNet's revised regulatory proposal:

- advised of an error in SP AusNet's description of 'New Connections' services and confirmed that its 'New Connections' services are those that involve connections less than 100 amps, while connections greater than 100 amps are quoted services
- rejected the AER's draft decision to incorporate the labour escalators approved in the draft decision for standard control services
- rejected the AER's draft decision price for Multi phase Overhead—CT connected meters - After hours
- rejected the AER's draft decision price for Overhead Supply—Coincident Disconnection (truck visit)—After hours
- proposed prices for New connections where SP AusNet is not responsible for metering, as requested in the AER's draft decision
- provided further information on SP AusNet's 'After hours truck by appointment' service, as requested in the AER's draft decision.

Consultant review

The AER did not seek advice from Impaq on SP AusNet's revised proposal for fee based alternative control services.

Issues and AER considerations

Routine new connection services definition

The AER notes SP AusNet's correction of its description of New Connections services, and agrees that the prices for New Connections are for connections less than 100 amps.

Incorporation of escalators within alternative control services prices

As noted above, the AER considers that it is appropriate that any escalators incorporated within prices for alternative control services should be equal to those approved for standard control services.

The AER's consideration of the DNSPs' proposed cost escalators is outlined in appendix K. In accordance with appendix K, the approved cost escalators for SP AusNet (which are incorporated within the AER's final decision prices for field officer visits, new connections and service vehicle visits) are set out in table 20.15.

Table 20.15 AER approved outsourced labour escalators for SP AusNet (per cent)

	2011	2012	2013	2014	2015
Internal labour	1.07	1.98	2.38	3.33	2.20
Outsourced labour	0.82	1.84	2.38	3.13	2.09

Source: Appendix K.

The AER has used the escalators listed in table 20.15 in generating final decision prices for SP AusNet's alternative control services for 2011–15, listed in appendix Q.

Multi phase Overhead—CT connected meters—After hours

The draft decision approved price for SP AusNet's Multi phase Overhead—CT connected meters—After hours service reflected a 35 per cent reduction on SP AusNet's proposed price.

After receiving SP AusNet's revised regulatory proposal, the AER questioned the calculation of the proposed price for this service, and discovered errors on both the AER's and SP AusNet's models generating prices for these services. In response to AER questions on this service, SP AusNet acknowledged an oversight in its calculations, and proposed a revised price, which was $493.59 ($, 2010).[105] This reflects a 6 per cent reduction on SP AusNet's revised proposal price, which was $521.07 ($, 2010).

The AER has compared SP AusNet's revised price for Multi phase Overhead—CT connected meters—After hours service to its approved prices for similar services provided by CitiPower, Powercor and JEN. The AER notes that SP AusNet's proposed charge falls below those approved using a cost build up of Impaq's recommended labour rates and times. Accordingly, the AER accepts SP AusNet's proposed price for Multi phase Overhead—CT connected meters—After hours, aside from the use of cost escalators, as detailed above. After inputting the AER's final decision on cost escalators, the final decision price for SP AusNet's Multi phase Overhead—CT connected meters after hours is $478.26 ($, 2010).

Overhead Supply—Coincident Disconnection (truck visit) —After hours

SP AusNet questioned the AER's decision to reduce its proposed price for Overhead Supply—Coincident Disconnection (truck visits) —After hours.[106]

After reviewing SP AusNet's revised proposal, the AER became aware that its draft decision set a charge which was above the cost build up price generated using Impaq's advice on hourly labour rates and times. Had the AER correctly followed its documented approach to reviewing SP AusNet's proposed charge for this service, it would have approved a maximum price of $239.24 for business hours in the draft decision, and $268.09 for after hours, rather than $353.92 and $538.99 respectively ($, 2010).

[105] SP AusNet, *Response to information requested on 6 August 2010,* 10 August 2010.
[106] SP AusNet, *Revised regulatory proposal*, p. 387.

The AER consulted with SP AusNet regarding this error. In response, SP AusNet accepted the AER's and Impaq's assessment of a reasonable maximum price for this service.[107]

The AER compared SP AusNet's revised proposed price for Overhead Supply—Coincident Disconnection (truck visits) with the cost build up for CitiPower, Powercor and JEN using Impaq's revised advice on the hourly charge out rates and times for this final decision.

For business hours, SP AusNet's revised proposed price is less than the price generated by a cost build up using Impaq's advice on maximum benchmark labour rates and times. Accordingly the AER accepts SP AusNet's proposed 2011 price, aside from the use of cost escalators in the calculation, as detailed above.

For after hours, SP AusNet's proposed price is above the highest cost build up price generated using Impaq's advice. As discussed above, the AER considers that Impaq's recommended maximum benchmark labour rates (adjusted to incorporate a 3 per cent margin above overheads) are a reasonable reflection of the maximum cost an efficient DNSP would incur in providing alternative control services, plus an appropriate margin. The AER also considers that Impaq's assessment of the maximum likely time in which each component of the services could reasonably be carried out is appropriate. Accordingly the AER's final decision is to reject SP AusNet's proposed 2011 charge of $570.15 and approve a charge of $466.47 ($, 2010). This charge is the maximum price generated using Impaq's advice on hourly labour charge out rates and times for similar services.

New connections services where SP AusNet is not responsible for metering

SP AusNet's revised proposal included proposed prices for 'new connections' services where SP AusNet is not responsible for metering. The proposed prices were not provided in SP AusNet's initial regulatory proposal.

The draft decision acknowledged a derogation (rule 9.9B of the NER) which requires that the Victorian DNSPs are responsible for all customers' (consuming less than 160MWh per annum and without a type 1 or 2 meter) meters from 1 July 2009. Clause 9.9B.2 of the NER provides that the derogation is to expire on 31 December 2013 or the commencement of other associated amendments to the NER (whichever is earlier). As the forthcoming regulatory control period extends beyond 31 December 2013, the draft decision noted that the Victorian DNSPs will need to have charges for new connections where the DNSP is not the responsible person for the regulatory years 2014 and 2015.[108]

SP AusNet submitted in its revised regulatory proposal that its 'new connections' prices where it is not the responsible person for metering are the same as its 'new connections' prices where it is responsible for metering. SP AusNet stated that there is no material difference in the cost for SP AusNet to connect a customer, regardless of whether it is responsible for the meter or not.[109]

[107] SP AusNet, *Response to information requested on 17 August 2010*, 27 August 2010.

[108] AER, *draft decision*, p. 874.

[109] SP AusNet, *Revised regulatory proposal*, p. 389.

The AER has considered SP AusNet's proposed prices for new connections prices where it is not the responsible person for metering by benchmarking the prices against those approved for CitiPower, Powercor and JEN using Impaq's recommended hourly labour rates and times. SP AusNet's proposed charges are lower than those resulting from the cost build up for CitiPower, Powercor and JEN. After considering Impaq's advice, the AER accepts SP AusNet's proposed prices for new connections where SP AusNet is not responsible for metering, aside from the use of cost escalators, as discussed above.

After hours truck by appointment service

The AER's draft decision requested that SP AusNet provide further information on its 'After hours truck visit by appointment' service.[110] SP AusNet's revised regulatory proposal stated that this service:

- involves a fee being charged to SP AusNet by its service provider which incorporates both work done after hours on a weekday as well as weekend work
- involves work that is on single phase or multi phase installations
- could involve electrical or structural alterations to the installation, replacement of metering equipment, re-fitting of existing metering, replacement of overhead service cables, if required. [111]

The AER asked SP AusNet for further information on this service, and noting the variable nature of the fee, suggested that classification as a quoted alternative control service would be more appropriate. In response, SP AusNet stated that it was indifferent between the service being fee based or quoted, provided that the AER approve its proposed after hours rates for quoted services.[112] In this final decision, the AER has classified SP AusNet's 'After hours truck visit by appointment' as a quoted service. The AER's consideration of SP AusNet's proposed quoted service hourly labour rates is provided in section 20.6.2.4.

AER conclusion

The AER rejects SP AusNet's revised proposed prices for fee based alternative control services. The AER's final decision prices for SP AusNet incorporate the AER's final decisions on cost escalators for standard control services, set out in table 20.15.

The AER rejects SP AusNet's revised proposed price for Overhead Supply—Coincident Disconnection (truck visits)—after hours, and approves a charge of $466.47 ($, 2010), based on a cost build up using Impaq's revised advice on times and labour rates.

For the final decision, the AER has classified SP AusNet's After hours truck visit by appointment service as a quoted alternative control service. The AER's consideration

[110] AER, *draft decision*, p. 884. The AER notes that the draft decision incorrectly referred to this service as 'after hours service truck visits,' however Appendix O of the draft decision requested information about SP AusNet's 'Truck Appointment-AH.' These references should have been 'After hours truck by appointment.'

[111] SP AusNet, *Revised regulatory proposal*, p. 389.

[112] SP AusNet, *Response to information requested on 17 August 2010*, 27 August 2010.

of SP AusNet's proposed quoted service hourly labour rates is provided in section 20.6.2.4.

The draft decision accepted SP AusNet's proposed price path for fee based alternative control services, and accordingly the AER maintains its draft decision on SP AusNet's price path for alternative control services.

20.6.1.4 United Energy

AER draft decision

The draft decision outlined the AER's consideration of the methodology applied by United Energy in calculating proposed charges for fee based alternative control services, noting that in most cases the proposed charges reflected the outcome of a competitive tendering process.

United Energy's proposed charges were based on prices submitted by a winning consortium bidder (winning bidder), however the AER found that in some cases, the winning bidder service prices had been escalated arbitrarily by United Energy.[113] While the AER accepted United Energy's allocation of overheads to the services, it did not accept the arbitrary inflation of prices, which were made to either discourage customer demand for after hours services, or to account for substantial differences between the current (2010) prices and winning bidder prices. On this basis the draft decision did not accept United Energy's proposed prices for the following services:

- temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—BH
- temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—AH
- temporary supplies (exc. inspection)—independent disconnection—multiphase to 100A—BH
- new connections where United Energy is responsible for metering—single phase single element—AH
- new connections where United Energy is responsible for metering—single phase two element (off peak)—AH
- new connections where United Energy is responsible for metering—three phase direct connected—AH
- new connections where United Energy is not responsible for metering—single phase single element—AH
- new connections where United Energy is not responsible for metering—single phase two element (off peak)—AH

113 AER, *draft decision*, pp. 886–887.

- new connections where United Energy is not responsible for metering—three phase direct connected—AH

- service vehicle visits (without inspection)—first 30 minutes—AH

- wasted service truck visit—AH.[114]

The draft decision also rejected United Energy's proposed charges for the provision of possum guards, security lighting installation or meter provision for first tier customers consuming more than 160 kWh per annum, as the AER considered these services were contestable and did not classify them in the draft decision.

The draft decision rejected United Energy's proposed charges for meter data services for small (less than 160kWh/annum) customers. This was because the AER considered cost recovery for meter data services for customers consuming less than 160kWh/annum was provided as part of the AER's AMI determination in October 2009.

The draft decision accepted United Energy's proposed price path for fee based alternative control services, being:

$p_t \leq p_{t-1} \times (1+CPI_t) \times (1-X)$, where $X = 0$[115]

United Energy revised regulatory proposal

United Energy's response to the AER's draft decision on its fee based alternative control services acknowledged the arbitrary inflation of prices identified by the AER, however also submitted proposed (higher) prices for most of these services, based on new prices submitted by its winning bidder.[116]

United Energy submitted that for meter data services and meter provision for customers consuming more than 160 MWh per annum, costs were not recovered under the AMI cost recovery process, and accordingly regulated charges are required as part of the AER's distribution determination.[117]

Consultant review

The AER did not seek advice from Impaq on United Energy's revised regulatory proposal for fee based alternative control services.

Issues and AER considerations

Revised winning bidder charges and arbitrary inflation of charges

United Energy submitted revised prices for most services that the AER had rejected prices for in its draft decision. The only exception was Temporary supplies (exc.

[114] AER, *draft decision*, p. 889. The AER notes that in the draft decision, while the AER rejected United Energy's arbitrary inflation of wasted service truck visit (AH), as set out in Appendix O, this service was missed out on the list of rejected services on page 889 of the draft decision.
[115] AER, *draft decision*, p. 889.
[116] United Energy, *Revised regulatory proposal*, p. 339.
[117] ibid.

inspection)—coincident disconnection—multiphase to 100A—business hours, for which United Energy accepted the draft decision price.[118]

The AER sought information from United Energy to support its revised charges for the following services:

1. Temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—AH
2. Temporary supplies (exc. inspection)—independent disconnection—multiphase to 100A—BH
3. New connections where United Energy is responsible for metering—single phase single element—AH
4. New connections where United Energy is responsible for metering—single phase two element (off peak)—AH
5. New connections where United Energy is responsible for metering—three phase direct connected—AH
6. New connections where United Energy is not responsible for metering—single phase single element—AH
7. New connections where United Energy is not responsible for metering—single phase two element (off peak)—AH
8. New connections where United Energy is not responsible for metering—three phase direct connected—AH
9. Service vehicle visits (without inspection)—first 30 minutes—AH
10. Wasted service truck visit—AH.[119]

United Energy indicated that prices for these services were either not submitted or incorrectly submitted as part of the winning bidder's proposal to provide the services, and that United Energy was working with the winning bidder to insert the revised prices into the relevant contract.

United Energy provided evidence of the winning bidder's revisions to these prices, which accorded with the revised prices submitted by United Energy, for services 3 to 10 above.[120]

The AER notes that United Energy's revised proposed prices for services 3 to 10 above are lower than the equivalent draft decision benchmark prices generated for CitiPower, Powercor and JEN using Impaq's advice on hourly labour charge out rates and times.

For services 1 and 2 above, United Energy did not provide a reason for its revised prices being higher than the initial winning bidder price, nor evidence of the winning bidder's revision to these charges. Nor did United Energy provide substantiation of the

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118 ibid., p. 340.
119 AER, *United Energy information request*, 6 August 2010.
120 United Energy, *Response to information request on 6 August 2010*, 17 August 2010. Evidence is in the form of an email between the winning bidder and United Energy setting out revised prices.

inflation of initial winning bidder prices (which were in the initial price model submitted with United Energy's regulatory proposal).

The AER benchmarked United Energy's revised proposed prices against the other Victorian DNSPs' prices for similar services. As United Energy's proposed prices for services one and two fall below the reasonable range generated by inputting Impaq's advice on the hourly labour charge out rates and times for CitiPower, Powercor and JEN, the AER accepts United Energy's revised proposed prices for these services.

Meter data services and meter provision charges for customers > 160 MWh/annum

The draft decision rejected United Energy's proposed prices for meter data services for customers consuming less than 160 MWh per annum, as it considered these services were covered by the AMI Order in Council. The draft decision also rejected United Energy's proposed meter provision charges for customers consuming more than 160MWh per annum, as it considered that these services are contestable.

In a legacy unique to United Energy's network, there are still some large (>160MWh/annum) customers with manually read meters. However, most large customers have been moved onto remotely read meters, for which there is a contestable market. The Framework and approach paper set out the AER's consideration of meter data services for existing large customers with manually read (types 5 and 6) interval meters.[121] The Framework and approach paper stated that:

> 'customers of type 5 and type 6 meter services have a choice of service provider other than a DNSP given that a type 4 meter service is a substitute for a type 5 or type 6 metering service.'[122]

The AER maintains its Framework and approach paper position that meter data services for large customers are contestable, as these customers have the choice to move to a remotely read interval meter. These services are not classified in this final decision. Accordingly, the AER has not set a charge for meter data services for customers consuming more than 160MWh per annum with a manually read meter.

AER conclusion

The AER accepts United Energy's revised proposed prices for its fee based alternative control services, aside from its proposed charge for meter data services for customers consuming more than 160MWh per annum with a manually read meter. The AER has not set charges for this meter data service as it is a contestable service and is not classified in this final decision. The draft decision accepted United Energy's proposed price path for fee based alternative control services and accordingly the AER affirms its draft decision on United Energy's price path for fee based alternative control services as the final decision.

20.6.2 Quoted alternative control services

Chapter 2 of this final decision sets out the classification of alternative control quoted services in the forthcoming regulatory control period, listed in table 20.16.

121 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, p. 42.

122 ibid.

Table 20.16 AER conclusion on service classification of alternative control quoted services for 2011–2015 regulatory control period

Quoted alternative control services
Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets
Supply enhancement at customer request
Supply abolishment
Emergency recoverable works (that is, emergency works where customer is at fault and immediate action needs to be taken by the DNSP)
Auditing of design and construction
Specification and design enquiry fees
Elective underground service where an existing overhead service exists
Damage to overhead service cables pulled down by high load vehicles
High load escorts—lifting overhead lines
Covering of low voltage mains for safety reasons
Routine connections, for customers > 100amps
After hours truck by appointment

Source: Appendix B of this final decision.

20.6.2.2 CitiPower and Powercor

AER draft decision

The draft decision rejected CitiPower's and Powercor's proposed quoted services labour rates for 2011. The labour rates approved in the draft decision for quoted services were based on Impaq's advice on labour rates for distribution line workers. Approved labour rates for quoted services were set out in appendix O of the draft decision.

The draft decision approved CitiPower's and Powercor's escalation of the approved 2011 quoted services labour rate by reference to the outsourced labour escalation approved for standard control services in that decision.

CitiPower's and Powercor's revised regulatory proposals

CitiPower's and Powercor's comments on Impaq's recommended labour rates for fee based alternative control services, set out in section 20.3.1, also apply to the labour rates for quoted services. CitiPower and Powercor submitted revised proposed labour rates for quoted services as set out in table 20.17.[123]

[123] CitiPower, *Revised regulatory proposal*, p. 447 and Powercor, *Revised regulatory proposal*, p. 448.

Table 20.17 CitiPower and Powercor—2011 proposed labour charge out rates for quoted services ($, 2010)

	CitiPower	Powercor
General Line worker—BH	115.14	112.11
General Line worker—AH	126.61	123.38
Design/survey—BH	123.56	120.31
Design/survey—AH	139.16	135.50
Administration	47.85	45.34

Source: CitiPower *Revised regulatory proposal*, p. 447; Powercor *Revised regulatory proposal,* p. 448.

CitiPower and Powercor proposed design/survey hourly labour rates for workers carrying out their audit design service, which was proposed as a standard control service in their initial proposals, but was classified as quoted alternative control service in the draft decision.

CitiPower and Powercor concurred with the draft decision that prices of materials for quoted service should bet set at the cost of the materials as incurred by CitiPower and Powercor.

CitiPower and Powercor proposed X factors for quoted alternative control services labour rates based on their proposed real labour escalators for standard control services, as set out in table 20.18.

Table 20.18 CitiPower's and Powercor's proposed X factors for quoted alternative control services labour rates (per cent)

2012	2013	2014	2015
–5.0%	–4.6	–4.0	–3.6

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.

Source: CitiPower, *Revised regulatory proposal*, p. 447; Powercor, *Revised regulatory proposal*, p. 448.

Consultant review

The AER did not ask Impaq to revise its advice on quoted service hourly labour charge out rates in response to the Victorian DNSPs' revised proposals. However, the amendments made to Impaq's hourly charge out rates for line workers, back office workers and schedulers undertaking fee based alternative control services are relevant to quoted alternative control services labour rates.

Issues and AER considerations

The AER has considered the issues raised by CitiPower and Powercor regarding line worker charge out rates for fee based services, as outlined in section 20.6.1.2. Impaq revised its recommended range of rates in response to the issues raised. The AER considers the revisions to the Impaq rates apply equally to quoted services hourly labour rates.

The AER considers that the majority of the tasks involved in CitiPower's and Powercor's quoted services are consistent with the labour classification of a distribution line worker. However, the AER agrees that there is work of a different nature performed by administrators or back office workers and design/survey staff within certain quoted services.

Accordingly, for the same reasons as set out in section 20.6.1.2, the AER's final decision on quoted service labour rates is to apply the highest point of Impaq's revised recommended ranges of line worker labour rates and back office workers, adjusted to include 3 per cent margin above overheads, where CitiPower's and Powercor's rates are above the range. For the design/survey labour classification, the AER has considered CitiPower's and Powercor's proposed rates against similar design rates approved in the draft decision for SP AusNet.

As noted above for fee based services, Impaq considered that where a vehicle is required for a service, higher rates are appropriate for CitiPower and Powercor as vehicle costs are not included in their cost build up. Similarly, the final decision approved line worker hourly labour rates for CitiPower's and Powercor's quoted services incorporate the cost of a vehicle. The AER has assumed that a single line worker in a vehicle will perform the majority of the quoted services, and accordingly has used the Impaq recommended rate for a single person crew including a vehicle, adjusted to incorporate a 3 per cent margin above overheads.

For the design/survey workers, the AER has taken the approved design worker rates for SP AusNet (reviewed by Impaq in its initial report) and applied escalation equivalent to the escalation applied to single crew line worker rates, reflecting the cost of a vehicle. For back office/administration work, no vehicle is required. As CitiPower's and Powercor's proposed hourly rates fall below the Impaq recommended range for back office workers, the AER has approved the proposed rates.

Table 20.19 AER final decision—CitiPower's and Powercor's quoted alternative control services hourly labour rates ($, 2010)

	CitiPower—Proposed (no vehicles)	CitiPower—AER final decision	Powercor—Proposed (no vehicles)	Powercor—AER final decision
General Line worker including vehicle—BH	115.14	116.36	112.11	108.76
General Line worker including vehicle—AH	126.61	128.91	123.38	120.54
Design/survey worker including vehicle—BH	123.56	110.68	120.31	103.45
Design/survey including vehicle—AH	139.16	130.36	135.50	121.89
Administration (no vehicle needed)	47.85	47.85	45.34	45.34

Source: CitiPower *Revised regulatory proposal*, p. 447; Powercor *Revised regulatory proposal*, p. 448; AER analysis.

Consistent with the final decision for fee based alternative control services, the AER will apply the approved cost escalators for standard control services in generating the X factors for CitiPower's and Powercor's quoted alternative control services labour rates for 2012–15.

The AER's final decision on cost escalators for standard control services is set out in appendix K of this final decision. The outsourced labour escalators to apply to CitiPower's and Powercor's quoted services labour rates are provided in appendix K, and the approved X factors are set out in table 20.20.

Table 20.20 AER final decision—CitiPower's and Powercor's X factors for quoted alternative control services labour rates (per cent)

2012	2013	2014	2015
–1.99	–2.39	–3.33	–2.20

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.

Source: CitiPower and Powercor, *response to information requested 12 October 2010*, 15 October 2010.

AER conclusion

The AER rejects CitiPower's and Powercor's proposed hourly labour rates for quoted services. The AER's final decisions on hourly labour rates for CitiPower's and Powercor's quoted services are based on advice from Impaq, as set out in table 20.19.

The AER rejects CitiPower's and Powercor's proposed X factors for the escalation of hourly labour rates for quoted services over 2012–15. The AER's approved X factors incorporate it's approved cost escalators for standard control services, set out in table 20.20.

20.6.2.3 Jemena Electricity Networks (JEN)

AER draft decision

The draft decision rejected JEN's proposed quoted services labour rates. The AER's approved labour rate was based on Impaq's advice based on the reasonable range of distribution line worker rates. Approved rates were set out in appendix O of the draft decision.

The draft decision applied an escalation of the approved 2011 quoted services labour rate by reference to the outsourced labour escalation it approved for standard control services discussed in appendix K of the draft decision.

JEN's revised regulatory proposal

JEN revised its list of quoted services in accordance with the AER's draft decision to include temporary covering of low voltage mains and service lines and routine connections as quoted services for customers > 100amps. In addition, JEN listed its elective underground service as a separate quoted service in its revised proposal.[124]

JEN revised its charge out rates and X factors for quoted services. JEN's revised proposed rates are for a line worker, excluding the cost of a vehicle.[125]

JEN agreed with the AER's draft decision that materials for quoted services are to be recovered at cost, and proposed to determine its charges for covering of low voltage mains by applying the AER approved labour rates for quoted services, plus $5 per 'tiger tail' per use. For routine connections for customers > 100amps, JEN proposed to determine charges by applying the approved labour unit rate per hour, with material and plant costs being passed onto customers at the same cost that JEN incurs.[126]

Table 20.21 JEN's revised proposal labour charge out rate and X factors for quoted services ($, 2010)

	2011	2012	2013	2014	2015
Line workers—BH	81.82	84.52	87.37	89.89	92.31
Line workers—AH	101.28	105.65	109.21	112.36	115.38
X factor (per cent)	–2.54	–3.29	–3.37	–2.89	–2.68

Note: Negative X factors convert to positive price increases in the CPI–X control mechanism.
Source: JEN, *revised regulatory proposal*, p. 347.

Consultant review

The AER did not ask Impaq to revise its advice on quoted service hourly labour charge out rates in response to the Victorian DNSPs' revised proposals. However, the amendments made to Impaq's hourly charge out rates for line workers undertaking fee based alternative control services are relevant to quoted alternative control services labour rates.

[124] JEN, *Revised regulatory proposal*, p. 342.
[125] ibid., p. 347.
[126] ibid., p. 342.

Issues and AER considerations

The AER has considered the issues raised by JEN regarding line worker charge out rates for fee based services, as outlined in section 20.6.1.3. Impaq revised its recommended range of rates in response to the issues raised. Consistent with the final decision on quoted services labour rates for CitiPower and Powercor, the AER considers the revisions to the Impaq rates apply equally to JEN's quoted services hourly labour rates.

The AER adjusted Impaq's recommended rates for line workers, incorporating a 3 per cent margin above overheads, as discussed above and set out in table 20.14. As JEN's proposed quoted service hourly rates are below the highest point in Impaq's recommended range, adjusted to include a 3 per cent margin above overheads, the AER has approved JEN's proposed hourly rates for quoted services in this final decision.

Consistent with the AER's final decision for fee based alternative control services X factors, the AER rejects JEN's proposed X factors for quoted alternative control services labour rates, and considers that it is appropriate to apply X factors that incorporate the cost escalators approved for standard control services, in appendix K. The AER's final decision on JEN's X factors for quoted alternative control service labour rates is set out in appendix Q.

AER conclusion

The AER approves JEN's proposed quoted services hourly labour rates for 2011, set out in table 20.21. The AER rejects JEN's proposed X factors and approves X factors that incorporate the AER's final decisions on cost escalators for standard control services. The AER's final decision on JEN's X factors for quoted alternative control service labour rates is set out in appendix Q.

20.6.2.4 SP AusNet

AER draft decision

The draft decision approved SP AusNet's proposed 2011 labour rates for quoted services, which consisted of a schedule of prices for different types of work relating to the services which the AER classified as quoted.[127]

The draft decision approved escalation of SP AusNet's 2011 prices over 2012–15 by the outsourced labour escalator it approved for standard control services.[128]

SP AusNet's revised regulatory proposal

SP AusNet accepted the draft decision on its 2011 labour rates for quoted services and the AER's decision to escalate these rates by the approved outsourced escalator for standard control services.[129]

[127] AER, *draft decision*, p. 906, and appendix O.
[128] ibid., p. 906. Escalators were provided in appendix K of the draft decision.
[129] SP AusNet, *Revised regulatory proposal*, p. 390. The AER notes that SP AusNet stated its acceptance of this approach but did not indicate its acceptance of the AER's approved outsourced labour escalator for any other purpose.

Consultant review

The AER did not seek advice from Impaq on SP AusNet's revised proposal for quoted alternative control services.

Issues and AER considerations

The AER's final decision on service classification, set out in chapter 2, is that SP AusNet's proposed after hours truck visit—by appointment is to be a quoted service. In response SP AusNet proposed after hours rates for quoted services, as set out in table 20.22.

Table 20.22 SP AusNet's proposed quoted services hourly labour charge out rates ($, 2010)

	Labour category	Service description	Business hours	After hours
1	Labour—wages	Construction Overhead Install	76.33	95.41
2	Labour— wages	Construction Underground Install	77.14	96.43
3	Labour—wages	Construction Substation Install	77.14	96.43
4	Labour—wages	Electrical Tester Including Vehicle & Equipment	113.04	141.3
5	Labour—wages	Construction	76.33	95.41
6	Labour—wages	Planner Including Vehicle	104.3	130.38
7	Labour—wages	Supervisor Including Vehicle	104.3	130.38
8	Labour—design	Design	81.01	101.26
9	Labour—design	Drafting	63.79	79.74
10	Labour—design	Survey	75.95	94.94
11	Labour—design	Tech Officer	75.95	94.94
12	Labour—design	Line Inspector	63.79	79.74
13	Labour—design	Contract Supervision	75.95	94.94
14	Labour—design	Protection Engineer	81.01	101.26
15	Labour—design	Maintenance Planner	75.95	94.94

Source: SP AusNet, *email to the AER*, 10 August 2010.

SP AusNet's proposed after hours rates for quoted services are equivalent to the after hours rates recommended by Impaq for fee based alternative control services. Having considered Impaq's advice the AER has accepted the proposed rates.

The AER notes SP AusNet's acceptance of its draft decision approved 2011 labour charge out rates for quoted services and escalation of the labour rates by the approved outsourced labour escalators for standard control services.

The AER's final decision on escalators is set out in appendix K of this final decision. The outsourced labour escalators to apply to SP AusNet's quoted services labour rate are provided in table 20.15.

AER conclusion

The AER affirms its draft decision prices for SP AusNet's business hours quoted alternative control services labour rates for 2011, set out in appendix Q. The AER approves SP AusNet's proposed after hours rates for quoted alternative control services, as set out in table 20.22. The 2011 rates will be escalated by the outsourced labour escalators, provided in table 20.15.

20.6.2.5 United Energy

AER draft decision

As United Energy's initial regulatory proposal did not include any labour rates for quoted alternative control services, the AER's draft decision did not approve a form of control for United Energy's quoted alternative control services and requested that United Energy provide labour rates in its revised regulatory proposal.

The draft decision noted the AER's intention that the 2011 prices should be escalated by the AER's approved outsourced labour escalation rate for standard control services.

United Energy's revised regulatory proposal

In its revised regulatory proposal United Energy submitted proposed hourly charge out rates for quoted services, as set out in table 20.23.

Table 20.23 United Energy proposed hourly charge out rates for quoted alternative control services ($, 2010)

Description	Proposed 2011 rate
Hourly labour rate—one person, business hours	79.80
Hourly labour rate—one person plus vehicle, business hours	108.90
Hourly labour rate—one person, after hours	99.75
Hourly labour rate—one person plus vehicle, after hours	121.56

Source: United Energy, *Revised regulatory proposal*, p. 344.

United Energy did not comment on the AER's draft decision that quoted services labour rates should be escalated over 2012–15 by the AER approved outsourced labour escalator for standard control services. The AER's approved outsourced labour escalator for standard control services is set out in table 20.24.

Table 20.24 AER final decision—outsourced labour escalators for United Energy (per cent)

	2011	2012	2013	2014	2015
Outsourced labour escalator	0.82	1.84	2.38	3.13	2.09

Source: Appendix K.

Consultant review

The AER did not seek advice from Impaq on United Energy's revised proposal for quoted alternative control services.

Issues and AER considerations

The AER has considered United Energy's proposed labour charge out rates for quoted services in the context of its decisions on the other Victorian DNSPs' labour charge out rates.

The AER notes that United Energy has proposed hourly labour rates for one person (without a vehicle) equivalent to the AER's draft decision on line worker labour rates for CitiPower, Powercor and JEN. The AER's final decision has increased CitiPower's, Powercor's and JEN's hourly labour rates for line workers from the draft decision rates, based on the arguments set out in sections 20.6.1.2 and 20.6.1.3 relating to daily work hours, public holidays and non-chargeable time. Accordingly, United Energy's proposed hourly rates for workers without a vehicle fall below the final decision rates for line workers.

United Energy's proposed labour charge out rates indicate it considers the cost of running a vehicle as $29.10 per hour in business hours and $21.80 after hours ($, 2010). The AER notes its analysis of CitiPower's proposed labour charge out rates for quoted services incorporating a vehicle, in section 20.6.1.2 above.

The AER compared United Energy's proposed labour rates incorporating a vehicle to the equivalent rates recommended by Impaq for CitiPower and Powercor. As United Energy's rates fall below the maximum approved line worker including a vehicle for CitiPower and Powercor, the AER accepts United Energy's proposed quoted services rates.

AER conclusion

The AER accepts United Energy's proposed hourly labour rates for quoted services, set out in table 20.23. Consistent with the AER's draft decision, United Energy's labour rates will be escalated over 2012–15 by the AER's approved outsourced labour escalation rate for standard control services, set out in table 20.24.

20.6.3 Compliance with the control mechanism for alternative control services

Under clauses 6.12.1(12) and 6.12.1(13) of the NER, the AER's distribution determination must set out a decision on how compliance with the control mechanisms for fee based and quoted alternative control services are to be demonstrated.

20.6.3.1 Draft decision

The draft decision stated that the Victorian DNSPs will be required to submit to the AER for approval an initial fee based alternative control price proposal for the first regulatory year of the forthcoming regulatory control period, and an annual pricing proposal for each subsequent regulatory year of the forthcoming regulatory control period.

It stated that the DNSPs' proposals should demonstrate compliance with the AER's determination on the form of control for the relevant regulatory year. The draft decision stated that annually approved prices for a DNSP's fee based alternative control services, to accord with the determination, must be published by each DNSP on its website.[130]

The draft decision stated that the unit costs for quoted services (being labour costs and the basis for materials charges) will be approved in the same manner as fee based services prices. That is, the Victorian DNSPs will be required to submit an annual proposal on the unit costs for quoted services, demonstrating compliance with the AER's control mechanism.

The annually approved unit costs for a DNSP's quoted alternative control services, to accord with the determination, must be published by each DNSP on its website. The draft decision stated that the timing of the annual alternative control services pricing proposal process should be consistent with the timing of the annual pricing proposal process for standard control services. That is, proposals must be submitted to the AER in accordance with clause 6.18.8 of the NER, being within 15 days of publication of the AER's final determination of prices for the first regulatory year (2011), and for each subsequent regulatory year of the forthcoming regulatory control period, within two months of the end of the regulatory year.[131]

20.6.3.2 DNSP revised proposals and submissions

The AER did not receive any submissions on its draft decision on how compliance with the control mechanisms for alternative control services is to be demonstrated. None of the DNSPs' revised proposals addressed this aspect of the AER's draft decision.

20.6.3.3 AER final decision

Given no issues were raised in the Victorian DNSPs' revised regulatory proposals or submissions on the AER's draft decision on how compliance with the control mechanisms for alternative control services is to be demonstrated, the AER maintains its draft decision.

Compliance with the control mechanism is to be demonstrated via an annual pricing proposal process.

For fee based alternative control services, the Victorian DNSPs must submit to the AER an initial price proposal for the first regulatory year of the forthcoming regulatory control period (2011), and an annual pricing proposal for each subsequent

130 AER, *draft decision*, p. 885.
131 ibid.

regulatory year of the forthcoming regulatory control period (years 2012–15). The initial pricing proposals for 2011 are to be equal to the AER's final decision prices for fee based alternative control services for 2011 (which are in $, 2010), escalated to $, 2011. The annual proposals for 2012–15 fee based service prices are to be generated by using the previous year's approved price and X factors approved in this final decision, as set out in appendix Q. The AER will assess the compliance of the proposed prices against this final decision, and provide a list of final approved prices for the relevant regulatory year, which is to be published by each DNSP on its website.

For quoted alternative control services, the Victorian DNSPs must also submit to the AER an initial proposal for labour rates for the first regulatory year of the forthcoming regulatory control period (2011), and an annual proposal of labour rates for each subsequent regulatory year of the forthcoming regulatory control period (years 2012–15). The initial proposals for 2011 labour rates are to be equal to the AER's final decision labour rates for quoted alternative control services for 2011 (which are in $, 2010), escalated to $, 2011. The annual proposals for 2012–15 quoted service labour rates are to be generated by using the previous year's approved labour rate and X factors approved in this final decision, as set out in appendix Q. The AER will assess the compliance of the proposed labour rates against this final decision, and provide a list of approved labour rates for the relevant regulatory year, which is to be published by each DNSP on its website.

The timing of the annual alternative control services pricing and labour rate proposal process should be consistent with the timing of the annual pricing proposal process for standard control services. That is, proposals for alternative control services prices and labour rates must be submitted to the AER in accordance with clause 6.18.8 of the NER, being within 15 days of publication of the AER's final determination of prices for the first regulatory year (2011). For each subsequent regulatory year of the forthcoming regulatory control period, the proposals must be submitted within two months of the end of the regulatory year.

20.7 AER conclusion

The AER's final decisions on 2011 prices and labour rates for fee based and quoted alternative control services are set out in appendix Q. The AER's final decisions on the X factors for fee based and quoted alternative control services prices for 2012–15 are also set out in appendix Q.

The AER's final decision prices for the Victorian DNSPs' fee based alternative control services are the result of analysis of the differing methodologies for calculating proposed prices and advice provided by Impaq on reasonable labour, materials and time inputs.

Due to significant variation between the Victorian DNSPs' proposed prices for similar services and the differing methodologies for generating their proposed prices, the resulting AER approved prices vary among the DNSPs for similar services.

As noted in the draft decision, while CitiPower, Powercor and JEN provided a cost build up for all services, SP AusNet carried out a top down analysis based on revenues and service volume forecasts, while United Energy's proposed prices were largely based on its winning bidder contractor's prices.

Analysis of the proposed prices revealed that a build up of costs resulted in higher prices, while a competitive tender process resulted in the majority of United Energy's fee based alternative control services prices being significantly lower than the other Victorian DNSPs' prices. SP AusNet's proposed prices were mostly in a range between the built up prices and United Energy's proposed prices.[132]

The AER determined prices, where different to those proposed by the Victorian DNSPs, have been calculated by the AER having regard to its decisions on cost inputs. The AER is confident that the maximum charges for each service incorporate reasonable inputs of labour charge out rates and times, such that the DNSPs are able to recover only the efficient costs of providing each service, plus a reasonable margin above overheads.

In accordance with clause 6.12.1(12) of the NER, the AER's final decision on the control mechanism for fee based and quoted alternative control services are:

- for fee based alternative control services, a price cap for 2011 prices and a CPI—X price path for 2012–15
- for quoted alternative control services, a cap on the hourly labour rates for 2011 and a CPI—X price path for 2012–15.

In accordance with clause 6.12.1(13) of the NER, compliance with the control mechanism for the above alternative control services is to be demonstrated via the annual pricing approval process as described in section 20.5.3.3 above.

Materials for quoted alternative control services are to be recovered at cost.

[132] ibid., p. 901.

21 Outcomes monitoring

As indicated in its draft decision, the AER intends to establish an outcomes monitoring framework to monitor the consistency of the Victorian DNSPs with the AER's 2011–15 Victorian distribution determinations, and increase the transparency and accountability of the service levels delivered to customers.

21.1 Regulatory requirements

The AER is responsible for the economic regulation of DNSPs in the national electricity market (NEM). Section 16 of the National Electricity Law (NEL) states that the AER must exercise its economic regulatory functions and powers in a manner that will or is likely to contribute to the achievement of the national electricity objective, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity
- the reliability, safety and security of the national electricity system.[1]

Clause 6.1.1 of the NER, states that the AER is responsible for the economic regulation of distribution services by means of, or in connection with, distribution systems that form part of the national grid.

Paragraph 28F(1)(a) of the NEL allows the AER to serve a regulatory information notice (RIN) on a DNSP if the AER considers it reasonably necessary for the performance or exercise of a function or power conferred on it under the NEL or the NER.

21.2 AER draft decision

The AER's draft decision stated that the purpose of the AER's outcomes monitoring framework was to monitor consistency with its distribution determinations and to increase transparency and accountability.[2] The draft decision set out the information AER intends to collect annually from the Victorian DNSPs, and the outcomes monitoring measures that the AER intends to establish for the forthcoming regulatory control period.

21.3 Victorian DNSP revised regulatory proposals

CitiPower, Powercor, JEN and United Energy all included an opex allowance in their revised proposals to account for the cost of implementing the outcomes monitoring framework set out in the AER's draft decision. The costing aspect of the revised proposals is discussed at chapter 7 of this final decision.

1 NEL, section 7.
2 AER, Draft decision, p.908.

CitiPower[3] and Powercor[4] note that the AER has not included the outcomes monitoring program in previous distribution determinations stating:

> CitiPower [Powercor] has reviewed the Previous Distribution Determinations and finds no reference to the outcomes monitoring program. This is perplexing given the creation of a national regulatory framework was intended to create consistency across jurisdictions, particularly in relation to the information being collected.

JEN notes that while the AER has stated its intention to replace the existing reporting requirements with its outcomes monitoring framework, it is not clear to JEN how this will be achieved, given the existing obligations arise from regulatory instruments issued by the Essential Service Commission Victoria (ESCV) under its powers.[5] JEN also states that the reporting requirements that the AER intends to establish are significantly more onerous than those which currently exist. Despite this, JEN states that it 'currently provides much of the information the AER has foreshadowed that it will require from DNSPs in the forthcoming regulatory control period'.[6]

21.4 Submissions

Origin supported the development of the AER's outcomes monitoring framework stating that there is,

> …considerable benefit in on-going monitoring of the level of actual expenditure, and the outcomes achieved by the Victorian DNSPs against the approved allowances in the AER's distribution determinations. This framework will better inform the AER in its assessments at the next Victorian distribution determinations, and improve the accountability of Victorian DNSPs.[7]

21.5 Issues and AER considerations

21.5.1 Issues raised in response to the AER's draft decision

CitiPower and Powercor state that the AER has not included an outcomes monitoring framework in its past distribution determinations. The AER has the power to collect information that is reasonably necessary for the performance or exercise of its functions or powers. The outcomes monitoring framework will ensure that the AER has the necessary information to assist it in exercising its regulatory functions and powers under the NER.

21.5.2 Safety related expenditure

Since the publication of the AER’s draft decision, the Victorian Government has amended the line clearance regulations which relate to vegetation management of Victorian DNSPs assets. In addition to the current requirements for reporting on safety related matters recorded in an Energy Safety Management Scheme, legislation regarding ESV auditing has been introduced. The Victorian DNSPs’ proposed both

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3 CitiPower, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p.206.
4 Powercor, *Revised Regulatory Proposal 2011 to 2015*, 21 July 2010, p.195.
5 JEN, *Revised Regulatory Proposal 2011–15, 20 July 2010*, p. 349.
6 ibid.
7 Origin, *Submission to the AER – Victorian Electricity Distribution Draft Determination and Revised Proposals*, 19 August 2010, p.6.

opex and capex to undertake works to meet these new regulatory requirements. Where consistent with the NER, the AER has provided an opex and capex allowance for these works.

Under the Victorian legislation and regulations, ESV has a monitoring role regarding works undertaken in relation to safety related aspects of these regulatory obligations. The AER notes that the ESV and the AER have different focus in the monitoring of the output and outcome of this program—ESV mainly on whether the quality and quantity of work done are adequate and consistent with the approved Energy Safety Management Scheme; whereas, the AER intends to focus on cost efficiency and unit cost movements.

The AER intends to complement the ESV's data collection framework with its own monitoring process, which will primarily focus on the costs of undertaking this program. The AER considers that, in combination, this monitoring arrangement will provide appropriate regulatory oversight of this works program, and enable an assessment of the efficiency and effectiveness of the outcomes achieved by the DNSPs.

In order to avoid duplication of reporting by the DNSPs, the AER intends to establish a co-ordinated information collection approach with ESV;[8] and, to the extent relevant, to share information with the ESV pursuant to the Memorandum of Understanding between the two organisations.

21.6 AER conclusion

Having considered the Victorian DNSPs' revised proposals and submission made on the AER 's draft decision, the AER considers it appropriate to implement an outcomes monitoring framework for the 2011–15 regulatory control period. Table 21.1 summaries the framework that the AER intends to implement to monitor the outcomes over the forthcoming regulatory control period.

8 ESV and the ESCV [now AER] are currently collecting gas DNSPs' performance information under a joined information reporting specification.

Table 21.1 Summary of outcomes monitoring and compliance measures

Monitoring or compliance measure	Purposes of information collection
Capital expenditure Financial reporting (actual capex spend) Reinforcement (augmentation) -*individual zone substations* -*individual distribution feeders* -*distribution transformers* Asset replacement (reliability and quality maintained) Customer Connections Expenditure programs to reduce bushfire risk Safety related expenditure	Provides for comparison between capex forecasts of Victorian DNSPs as approved by the AER in its distribution determinations, with actual expenditure in the regulatory control period. Better inform the AER in its assessment of the Victorian DNSPs in the next Victorian distribution determinations. Promote transparency and accountability in the Victorian DNSPs' investment and expenditure decisions, and the delivery of services to customers. Monitoring of the allowance given by the AER to SP AusNet and Powercor to mitigate bushfire risk.
Operating expenditure Actual operating and maintenance activities Failure rates Operational efficiency improvement resulting from the Advanced Metering Infrastructure (AMI) rollout program Safety related expenditure	Provides for comparison of opex forecasts of Victorian DNSPs as approved by the AER in its distribution determinations, with actual expenditure in the regulatory control period. Inform the AER of the impact of the Victorian DNSPs' asset replacement and operation and maintenance activities. Better inform the AER in its assessment of the Victorian DNSPs in the next Victorian distribution determinations. Promote transparency and accountability in the Victorian DNSPs' investment and expenditure decisions, and the delivery of services to customers.
Service standards reporting requirements *Reliability and quality of supply measure* *Customer services measure* *Worst served customers* *Network performance during major event days*	Monitoring the performance of the distribution network to improve transparency and for possible future application of the AER's STPIS.
Network statistics	Inform the AER in its assessment of the Victorian DNSPs in the next Victorian distribution determinations. Promote transparency and accountability in the DNSPs' investment and expenditure decisions, and the delivery of services to customers.
Service target performance incentive scheme	Ensure compliance with the AER's STPIS.

Monitoring or compliance measure	Purposes of information collection
Efficiency benefit sharing scheme	Ensure compliance with the AER's EBSS.
Demand management incentive scheme	Assessment of expenditure and compliance with the DMIA criteria, and approval of expenditures. Assessment of revenues foregone as a result of implementation of demand management projects approved under the DMIA, and approval of compensation.
Pass throughs	Confirm whether or not a positive or negative pass through event has occurred during the reporting period (a regulatory year).
Control mechanisms for standard control services and alternative control services	Monitoring the Victorian DNSPs' compliance with the control mechanisms as set out in clause 6.12.1(13) of the NER.
Annual inflation adjustment	Adjustment to the WAPC each year.
Actual demand quantities	Calculation of the WAPC each year.
Licence fees	Calculation of the WAPC each year.
Public lighting	Ensure that only those councils choosing to install energy efficient public lighting in their municipalities will pay for that service.

Glossary

ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
AECOM	Architecture Engineering Consulting Operations and Management
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AH	After hours
Ai Group	Australian Industry Group
AMA	Asset management agreement
AMI	Advanced metering infrastructure
ANSIO	Australian National State and Industry Outlook
ANZSIC	Australian and New Zealand Standard Industrial Classification 2006
AOFM	Australian Office of Financial Management
APR	Annual planning report (VENCorp)
ASIC	Australian Securities and Investments Commission
ASX	Australian Securities Exchange
ATO	Australian Taxation Office
AUD	Australian dollar
AWOTE	average weekly ordinary time earnings
BFV	Bloomberg fair value
BGN	Bloomberg generic yield
BH	Business hours
CALC	Consumer Action Law Centre
capex	capital expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CFA	Country Fire Authority

CFC	Construction Forecasting Council
CFL	compact fluorescent light
CGS	Commonwealth Government Security
Citelum	Citelum Australia Pty Ltd
CMEN	common multiple earthed neutral
COWP	Capital and Operational Work Plan
CPI	consumer price index
CPP	Critical peak pricing
CPRS	carbon pollution reduction scheme
CS	Customer Service
CT connected	Current transformer connected
CT/VT	current/voltage transformer
CUAC	Consumer Utilities Advocacy Centre
current regulatory control period	1 January 2006 to 31 December 2010
Darebin	Darebin City Council
DC	Direct connected
DEHWA	Department of Heritage, Water and the Arts
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DNOs	Distribution Network Operators
DNSP	distribution network service provider
DP	degree of polymerisation
DPI	Department of Primary Industries
draft decision	AER, Draft decision, Victorian draft distribution determination 2011 to 2015.
draft distribution determinations	AER, Victorian draft distribution determination, 2011 to 2015.
DRP	Debt risk premium
DTF	Victorian Department of Treasury and Finance
DUOS	Distribution use of system

EBA	enterprise bargaining agreement
EBSS	Efficiency benefit sharing scheme
ECM	Efficiency carryover mechanism
EDC	Electricity Distribution Code
EDPR	Electricity Distribution Price Review
EGW	electricity, gas and water
ELV	Electric vehicle
EPA	Environment Protection Authority Victoria
ESCOSA	Essential Services Commission of South Australia
ESCV	Essential Services Commission of Victoria
ESMS	electricity safety management scheme
ESV	Energy Safe Victoria
ETS	emissions trading scheme
ETSA	Electricity Trust of South Australia
EUAA	Energy Users Association of Australia
EUCV	Energy Users Coalition of Victoria
EWOV	Energy and Water Ombudsman (Victoria)
FIG	Financial Investor Group
Forthcoming regulatory control period	1 January 2011 to 31 December 2015
GDP	gross domestic product
GFC	Global financial crisis
GIS	Geographical Information System
GRP	Gross regional product
GSL	Guaranteed service level
GSP	gross state product
Guideline 14	Essential Services Commission of Victoria (ESCV), *Electricity Industry Guideline No. 14—Provision of Services by Electricity Distributors—Issue 1*, April 2004
GWh	Giga watt hour
HBRA	hazardous bushfire risk areas

HRC	Hot Rolled Coil
IEEE	Institute of Electrical and Electronic Engineers
IHD	In home display
Impaq	Impaq Consulting
IMRR	Interval meter reassignment requirements
IPART	Independent Pricing and Regulatory Tribunal
ISF	Institute for Sustainable Futures
IT	information technology
IVR	Interactive Voice Response
JAM	Jemena Asset Management
KPI	Key Performance Indicator
L factor	Licence fee factor
LBRA	low bushfire risk areas
LIBOR	London Interbank Offered Rate
LME	London Metal Exchange
LPI	labour price index
MAIFI	Momentary Average Interruption Frequency Index
MAV	Municipal Association of Victoria
MD	Maximum demand
MED	Major Event Day
MEPS	Minimum Energy Performance Standards
MJA	Marsden Jacobs Associates
MOU	Memorandum of Understanding
MRET	Mandated Renewable Electricity Target
MRP	Market risk premium
MSATS	Market settlement and transfer solution procedures
MTR	Maximum transmission revenue
MV80	Mercury Vapour 80
MVa	mega volt amperes

MW	mega watt
MWh	mega watt hour
NDSC	Negotiated Distribution Service Criteria
NECA	National Electrical Contractors Association
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERA	National Economic Research Associates, Inc.
NGERS	National Greenhouse and Energy Reporting Act 2007
NIEIR	National Institute of Economic and Industry Research
NPV	Net present value
NSLP	Net system load profile
NSW	New South Wales
NYMEX	New York Mercantile Exchange
Ofgem	Office of Gas and Electricity Markets
OMR	Operation, Maintenance and Repair
opex	operating expenditure
Origin	Origin Energy
PB	Parsons Brinckerhoff Strategic Consulting
PE cells	photo-electric cells
PFIT	Premium feed-in tariff
PLC	Public Lighting Code
PoE	Probability of exceedence
POEL	private overhead electric lines
PSAIDI	planned SAIDI
PTRM	Post tax revenue model
PV	photovoltaic

QCA	Queensland Competition Authority
QLD	Queensland
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
repex	Replacement expenditure
revised Order	The Order in Council made on 28 August 2007 by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000, as amended on 25 November 2008, 22 January 2009 and 31 March 2009.
RIN	Regulatory information notice
RIS	Regulatory impact statement
RIT–D	Regulatory Investment Test for Distribution
RMA	Road Management Act 2004 (Vic)
ROS	Reliability of Supply
SA	South Australian
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SBS	solar bonus scheme
SCONRRR	Steering Committee On National Regulatory and Reporting Requirements
SECV	State Electricity Commission Victoria
SFTUCF	S factor true up correction factor
SGC	Streetlight Group of Councils
SHP	Sodium High Pressure
SIR	Service and Installation Rules
SKM	Sinclair Knight Merz
SMS	short message service
SOO	Statement of opportunities (AEMO)
SORI	Statement of Regulatory Intent
STPIS	Service Target Performance Incentive Scheme

T5	energy efficient T5
TEC	Total Environment Centre
Tenix	Tenix Alliance Pty Ltd
TEV	transient earth voltage
TFP	Total Factor Productivity
TNSP	Transmission Network Service Provider
TOU	Time of use
TUoS	Transmission use of system
TWI	Trade weighted index
UED	United Energy Distributors
UK	United Kingdom
USA	United States of America
USD	US dollar
VAPR	AEMO's Victorian Annual Planning Report
VBRC	Victorian Bushfires Royal Commission
VCOSS	Victorian Council of Social Services
VCR	Value of Customer Reliability
VECCI	Victorian Employers Chamber of Commerce and Industry
VEET	Victorian Energy Efficiency Target
VSPLAG	Victorian Sustainable Public Lighting Action Group
WACC	Weighted average cost of capital
WAPC	Weighted average price cap
WMTS	West Melbourne terminal station
WTI	West Texas Intermediate
ZSS	zone substation