Draft decision

Queensland

Draft distribution determination 2010–11 to 2014–15

25 November 2009

AUSTRALIAN ENERGY REGULATOR

Request for Submissions

This document sets out the Australian Energy Regulator's (AER) draft distribution determinations for Energex and Ergon Energy (the Qld DNSPs) for the period 1 July 2010 to 30 June 2015.

The AER will hold a pre–determination conference on its draft distribution determinations on Tuesday 8 December 2009 in Brisbane for the purpose of explaining its draft determinations and receiving oral submissions from interested parties. Interested parties can register to attend the pre–determination conference by calling the AER on (02) 6243 1233 or by emailing QldSAdistribution@aer.gov.au by 4 December 2009.

Interested parties are invited to make written submissions on issues regarding these draft distribution determinations and the consultants' reports to the AER by 16 February 2010. The AER will deal with all information it receives in the distribution determination process, including submissions on the draft distribution determinations, in accordance with the ACCC/AER information policy. The policy is available at www.aer.gov.au.

Submissions can be sent electronically to QldSAdistribution@aer.gov.au.

Alternatively, submissions can be mailed to:

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GPO Box 3131
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The AER prefers that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non–confidential version of the submission.

All non–confidential submissions will be placed on the AER website, www.aer.gov.au.

A copy of the Qld DNSPs' regulatory proposals, consultancy reports and submissions from interested parties are available on the AER website.

Inquiries about the draft distribution determinations or about lodging submissions should be directed to the Network Regulation North Branch on (02) 6243 1233 or alternatively emailing QldSAdistribution@aer.gov.au.

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Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CPI	consumer price index
current regulatory control period	1 July 2005 to 30 June 2010
DNSP	distribution network service provider
EDSD Review	Queensland Department of Natural Resources, Mines and Energy, *Detailed Report of the Independent Panel, Electricity Distribution and Service Delivery for the 21st Century*, July 2004
EMS	Energy and Management Services
MMA	McLennan Magasanik Associates
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
next regulatory control period	1 July 2010 to 30 June 2015
opex	operating expenditure
PB	Parsons Brinckerhoff Strategic Consulting
QCA	Queensland Competition Authority
the Qld DNSPs	Energex and Ergon Energy

Overview

The regulatory framework

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 (NEM).

The AER's draft determination for Energex and Ergon Energy (the Qld DNSPs) for the 2010–2015 regulatory control period has been made under the relevant provisions of the NER and NEL. The AER must also consider a number of transitional requirements for Queensland that are set out in chapter 11 of the NER.

This is the first electricity distribution determination made by the AER on the revenue control regime to apply to the Qld DNSPs. The previous determination that applied to the Qld DNSPs for the period 2005–10 was made by the Queensland Competition Authority (QCA).

Review process

The review process commenced with the staged publication of the AER's framework and approach in July and November 2008. The purpose of the framework and approach is to set out the AER's likely approach to the classification of services and the application of the various schemes, such as the demand management incentive scheme.

Following the publication of the AER's framework and approach, the AER liaised with the Qld DNSPs to develop a Regulatory Information Notice (RIN) for each business. The purpose of the RINs was to obtain supporting information from the Qld DNSPs to assist the AER in its assessment of the regulatory proposals against the requirements of the NER.

The Qld DNSPs' regulatory proposals were published on the AER's website in July 2009. The AER received 11 submissions which were considered as part of this draft decision.

The AER's detailed examination of the Qld DNSPs' regulatory proposals was informed by advice from Parsons Brinckerhoff Strategic Consulting (PB). PB is an engineering and management consultancy firm with significant experience in the area of electricity distribution businesses. PB reviewed the regulatory proposals and supporting data supplied by the Qld DNSPs. PB assessed the regulatory proposals and provided advice to the AER on whether it considered the proposed expenditure was prudent and efficient.

In making its draft decision and draft distribution determination, the AER assessed the Qld DNSPs' regulatory proposals to determine if they were in accordance with the requirements of the NER. Expert engineering consultants, as well as financial and economic experts assisted the AER in its assessment of the proposals. The AER also considered the past performance of the Qld DNSPs and the effectiveness of their policies and procedures, both in terms of past performance and in the development of their regulatory proposals.

Key expenditure drivers and considerations

The Qld DNSPs overspent the regulatory allowances established by the QCA for the five year period ending 30 June 2010. Energex overspent its capital allowance by $357 million and its operating allowance by $140 million. Ergon Energy overspent its capital allowance by $822 million and its operating allowance by $78 million. The AER reviewed the reasons for these overspends and considered that they were reasonable in view of higher than expected demand at the commencement of the regulatory control period, the need for asset replacement capex and costs associated with improving network reliability and service standards.

The Qld DNSPs cited customer growth, growth in peak energy demand, improving the safety and reliability of their networks and replacement of aging assets as the key drivers of their expenditure proposals in the next regulatory control period.

While noting the impact of the global financial crisis (GFC) on capital markets the Qld DNSPs are forecasting that the GFC will have a more limited impact on economic activity in Queensland than first thought and therefore the need for network growth will continue.

The AER, based on advice from McLennan Magasanik Associates, reviewed each DNSP's demand forecasts and was not satisfied that the demand forecasts had properly factored in the impact of slower economic growth in 2009–10 resulting from the GFC.

The AER was also not satisfied that the materials and labour cost escalators used to forecast capital and operating expenditures reflected current economic conditions and considered that the escalators used by the Qld DNSPs were likely to overstate future costs. The AER has revised the cost escalators and will update these to reflect economic conditions at the time of the final decision.

PB's assessment of the Qld DNSPs' regulatory proposals confirmed the need for an increase in capital works expenditure in the next regulatory control period. Both have forecast large increases in spending to improve network security and reliability and for network augmentation to meet the needs of an increasing number of customers. Non–demand driven capital expenditure is also a significant portion of this expenditure, which incorporates large increases in areas such as asset replacement and safety expenditure.

After considering the Qld DNSPs' regulatory proposals against the capital expenditure criteria under chapter 6 of the NER, the AER concluded that Energex's and Ergon Energy's proposed capital expenditure is $748 million and $1020 million respectively higher than an efficient level. The AER's draft determination results in a 12 per cent and a 17 per cent reduction in the proposed capital expenditure of Energex and Ergon Energy respectively.

PB assessed the Qld DNSPs' operating expenditure proposals, and confirmed a need for higher operating expenditures over the next regulatory control period resulting from the increased size of the network and higher real input costs for network maintenance. A large part of the Qld DNSPs' operating costs are allocated to network maintenance expenditure and a significant proportion also relates to overheads. The

AER also applied revised input cost escalators to the opex forecast as noted above in regard to cost escalators for capital expenditure.

The AER concluded that Energex's and Ergon Energy's proposed operating expenditure for the next regulatory control period is $257 million and $479 million higher than an efficient amount. The AER's draft determination results in a reduction of 14 per cent and 24 per cent, respectively, on the proposed operating expenditure of each business.

The Qld DNSPs sought to vary the methodology the AER uses to determine the cost of capital for determining their allowed revenues. Both sought to add 79 basis points to the 10–year Commonwealth government securities yield which is used as one of the components to calculate the weighted average cost of capital (WACC). The AER has not accepted this proposal. For this draft decision the AER calculated an indicative nominal vanilla WACC of 10.06 per cent for both Energex and Ergon Energy. The nominal risk-free rate and debt risk premium—which impact on the WACC—and expected inflation rate will be updated closer to the date of the final decision.

Outcome of regulatory process

The AER has established the annual revenue requirement for the Qld DNSPs based on the AER's approved capital and operating expenditure allowances. Energex's total revenue for the next regulatory control period is $7158 million (nominal). Ergon Energy's total revenue for the period is $6364 million (nominal).

Energex's allowed revenues will increase in real terms by 23 per cent in 2010–11 compared to the preceding year. Ergon Energy's allowed revenues will increase in real terms by 27 per cent compared to the preceding year. Network prices will increase on average by a lower rate reflecting the partially offsetting effect of higher energy consumption.

The specific circumstances faced by the Qld DNSPs which justify these price increases are discussed in this draft decision. The average residential customer's annual electricity bill in 2010–11 is likely to increase by just over 9 per cent or around $133. Beyond 2010–11, further price rises for residential customers will be around 2 per cent or $31 each year. It is of course possible that factors other than distribution charges may cause price to vary including, for example, factors influencing wholesale energy costs.

This decision also implements three incentive schemes:

- the service target performance incentive scheme – which encourages network service providers to maintain or improve their service performance in terms of the number and incidence of outages on their network
- the efficiency benefit sharing scheme – which is designed to provide a fair sharing of efficiency benefits and losses between network service providers and network users

- the demand management incentive scheme – which is designed to provide incentives for network service providers to pursue and implement efficient non-network solutions to address growing demand on their networks.

Arrangements for establishing street lighting charges and charges for fee based and quoted services are also provided for in the draft decision.

Summary

Introduction

The Queensland Competition Authority (QCA) made the current regulatory determinations for Energex and Ergon Energy (the Qld DNSPs) for a five year period from 1 July 2005 to 30 June 2010 (the current regulatory control period). These DNSPs own and operate the electricity distribution networks in Queensland.

The AER assumes responsibility for regulating electricity distribution services provided by the Qld DNSPs from 1 July 2010. The distribution determinations for the period 1 July 2010 to 30 June 2015 (the next regulatory control period) are the first for the Qld DNSPs to be conducted by the AER under the National Electricity Rules (NER).

On 30 June 2009 the Qld DNSPs submitted their regulatory proposals for the next regulatory control period to the AER. On 17 July 2009 the AER published the proposals and its proposed negotiated distribution service criteria (NDSC) for the Qld DNSPs. Interested parties were invited to make submissions on the proposals and 11 submissions were received. The Qld DNSPs presented their regulatory proposals at a public forum held in Brisbane on 3 August 2009.

The AER engaged the following consultants to assist in the assessment of the regulatory proposals:

- Parsons Brinckerhoff Strategic Consulting (PB)
- McLennan Magasanik Associates (MMA)
- Energy and Management Services (EMS)
- Access Economics
- McGrathNicol Corporate Advisory (McGrathNicol).

This draft decision should be read in conjunction with the consultants' reports which are available on the AER's website.

The key decisions addressed in this draft decision for the Qld DNSPs are:

- classification of services
- specification of the control mechanisms and methodologies for demonstrating compliance with the control mechanism
- the opening regulatory asset base (RAB) values
- the AER's assessment of forecast capital expenditure (capex)
- the AER's assessment of forecast operating expenditure (opex)

- an estimate of the efficient benchmark weighted average cost of capital (WACC)
- the annual revenue requirement for each year of the next regulatory control period
- the NDSC that will apply to the Qld DNSPs
- the schemes to provide incentives to the Qld DNSPs to improve efficiency, maintain service standards and manage increasing demand.

The AER's consideration of each of these components is summarised below. Further detail is provided in the relevant chapters and appendices of this draft decision.

Regulatory requirements

National Electricity Law

The National Electricity Law (NEL) sets out the functions and powers of the AER, including its role as the economic regulator of utilities operating in the national electricity market (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:

> …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, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

National Electricity Rules

Chapter 6 of the NER sets out provisions 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 Qld DNSP that includes a:

- building block determination in respect of standard control services
- determination in respect of alternative control services
- determination specifying requirements relating to the negotiating framework
- determination specifying the NDSC.

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

Broadly, the NER requires the AER to:

- specify the classification of services that the AER is to apply

- specify the negotiating framework and NDSC to apply to the DNSP
- assess the DNSP’s control mechanism for standard control services
- set out the methodology for establishing the opening RAB
- assess the DNSP’s demand forecasts and cost inputs to achieve the capex and opex objectives
- set out the requirements for the DNSP’s regulatory proposal, including the requirement to forecast capex and opex necessary to meet the capex and opex objectives. These objectives include meeting the expected demand for standard control services, complying with all regulatory obligations or requirements and maintaining the quality, reliability and security of supply of standard control services and the reliability, safety and security of the distribution system through the supply of the standard control services
- assess whether the forecast capex and opex proposed by a DNSP reflect the efficient costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capex or opex objectives
- set out the methodology for calculating the estimated corporate income tax
- set out the methodology for calculating depreciation on the assets to be included in the RAB and assess whether or not to approve the depreciation schedules submitted by a DNSP
- set out the methodology for calculating the cost of capital
- develop and publish a service target performance incentive scheme (STPIS), efficiency benefit sharing scheme (EBSS) and demand management incentive scheme (DMIS)
- specify additional pass through events
- specify the DNSP’s annual revenue requirement for each year of the regulatory control period and set the X factor for each year of the regulatory control period
- set out the form of control the AER to apply to alternative control services
- set out how compliance with control mechanisms is to be demonstrated by the DNSP.

The relevant regulatory requirements set out under the NER are outlined in detail at the beginning of each chapter in this draft decision.

Classification of services

Qld DNSP regulatory proposals

The Qld DNSPs stated that their respective regulatory proposals were prepared consistent with the classification of services specified in the framework and approach paper.

AER conclusion

The AER has applied the service classifications set out in the framework and approach. The distribution service classifications are set out in appendix A of this draft decision. The AER's procedure for the Qld DNSPs to assign and reassign customers to tariff classes is set out in appendix B of this draft decision.

Arrangements for negotiation

Qld DNSP regulatory proposals

The Qld DNSPs do not have services classified as negotiated distribution services and did not submit negotiating frameworks.

AER conclusion

No negotiating frameworks will apply to the Qld DNSPs in the next regulatory control period.

The AER considers it is required to publish a NDSC to apply to the Qld DNSPs, irrespective of whether or not the Qld DNSPs have services classified as negotiated distribution services. The NDSC applying to the Qld DNSPs for the next regulatory control period is in appendix C of this draft decision.

Control mechanism for standard control services

Qld DNSP regulatory proposals

Energex

Energex proposed a revenue cap of a CPI–X form for its standard control services. It also proposed annual adjustments to its annual revenue allowance for:

- any under/over recoveries related to distribution use of system (DUOS) charges
- its performance against the STPIS
- adjustments for actual tax paid in 2008–09 and 2009–10
- any pass throughs approved by the AER during the next regulatory control period.

Energex also proposed a capital contribution bank to overcome the need for annual revenue adjustments for under/over recoveries related to capital contributions.

Energex proposed the same approach to the recovery of transmission use of system (TUOS) charges for the next regulatory control period as that used by the QCA during the current regulatory control period.

Ergon Energy

Ergon Energy proposed a revenue cap control mechanism of a CPI–X form for its standard control services. It also proposed annual adjustments to its annual revenue allowance for:

- any under/over recoveries related to DUOS charges
- any under/over recoveries related to capital contributions
- its performance against the STPIS
- use of standard control services assets by other businesses within Ergon Energy Corporation Limited
- any pass throughs (including solar bonus scheme/feed-in tariff payments and unfunded shared network events) approved by the AER during the next regulatory control period.

Ergon Energy proposed the same approach to the recovery of TUOS for the next regulatory control period as that used by the QCA during the current regulatory control period.

AER conclusion

The AER accepts the Qld DNSPs' proposals to apply a revenue cap form of control to their standard control services for the next regulatory control period.

The proposed annual adjustments by each of the Qld DNSPs are accepted by the AER, except for Energex's proposal to establish a capital contribution bank. The AER requires Energex to account for any under/over recoveries of capital contributions on an annual basis.

As part of their annual pricing proposals, the Qld DNSPs must submit to the AER proposed tariffs and charging parameters which result in expected revenues consistent with the maximum allowance revenue (MAR) formula set out below plus any adjustment needed to adjust the balance of their DUOS unders and overs account to zero (or the agreed tolerance level).

The MAR for the first year of the next regulatory control period will be set equal to the allowed revenue (AR) for the first year of the next regulatory control period:

$$MAR_1 = AR_1$$

where:

MAR_1 is the maximum allowed revenue for year 1 (that is, 2010–11) of the next regulatory control period.

AR_1 is the allowed revenue for year 1 of the next regulatory control period.

The MAR for the subsequent years of the regulatory control period requires annual adjustments based on the previous year AR. That is, the subsequent year AR is determined by adjusting the previous year AR for actual inflation and the X factor:

$$AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$

where:

AR is the allowed revenue

t is the regulatory year (excluding year 1)

ΔCPI_t is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in year t–2 to March in year t–1

X_t is the X factor for each year of the next regulatory control period.

The MAR is determined annually by adding to, or subtracting from, the AR any STPIS revenue increment (or revenue decrement) and any approved pass through amounts, as follows:

$$MAR_t = AR_t \pm S_t \pm C_t \pm transitional_t \pm passthrough_t$$

where:

MAR_t is the maximum allowed revenue for year t (excluding year 1) of the next regulatory control period

AR_t is the allowed revenue for regulatory year t

S_t is the STPIS factor to be applied in regulatory year t

C_t is the annual adjustment factor for the difference between actual and forecast capital contributions in year t–2 and indexed for two years by the nominal rate of return

$transitional_t$ is a transitional factor for matters such as under/over in tax paid during the current regulatory period and under/over adjustments related to standard shared assets used for purposes other than standard control services

$passthrough_t$ is the approved pass through amounts with respect to regulatory year t, as determined by the AER.

The AER accepts the Qld DNSPs' proposed approach to the recovery of TUOS charges.

In their annual pricing proposals, the Qld DNSPs will be required to demonstrate that their proposed DUOS prices for the next year will comply with the side constraints formula for each tariff class, specified in this draft decision.

Opening regulatory asset base

Qld DNSP regulatory proposals

Energex

Energex proposed an opening RAB for the next regulatory control period of $7984 million as at 1 July 2010. The proposed opening RAB was derived by taking an opening RAB of $4345 million as at 1 July 2005 and rolling this value forward to 1 July 2010.

Energex proposed an opening RAB as at 1 July 2005 that was higher than the RAB specified in the NER by $37 million. It stated this difference reflected the fact that its actual capex in 2004–05 was greater than the forecast allowance set by the QCA in its final determination.

Ergon Energy

Ergon Energy proposed an opening RAB for the next regulatory control period of $6999 million as at 1 July 2010. The proposed opening RAB was derived by taking the most recent RAB advised by the QCA of $4146 million as at 1 July 2005 and rolling this value forward to 1 July 2010.

Ergon Energy's opening RAB for the next regulatory control period included adjustments for removal of working capital by the QCA, the removal of street lighting assets and the removal of market metering assets incorrectly included in the RAB determined by the QCA.

AER conclusion

Energex

The RAB roll forward calculations for Energex are set out in table 1 and results in an opening RAB of $7887 million for standard control services as at 1 July 2010. The decrease in opening RAB reflects the use of a different inflation rate from that used by Energex as well as adjustments for actual capex differences, and exclusion of alternative control assets from the RAB.

Table 1: Opening RAB to apply to Energex ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB	4345.2	4996.7	5596.7	6248.6	7003.4
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	744.6	734.7	694.4	890.5	1048.0
Straight-line depreciation (adjusted for actual CPI)	–93.2	–134.7	–42.5	–135.7	–148.2
Closing RAB	4996.7	5596.7	6248.6	7003.4	7903.2
Difference between actual and forecast capex for 2004–05					53.1
Return on difference					27.3
Less: system assets moving from standard control services to alternative control services					–96.4
Opening RAB at 1 July 2010					7887.4

(a) Based on estimated net capex.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.

Ergon Energy

The RAB roll forward calculations for Ergon Energy are set out in table 2, and result in an opening RAB of $7105 million as at 1 July 2010.

The AER has determined an opening RAB that is higher than that proposed by Ergon Energy due to the use of a different inflation rate than that proposed by Ergon Energy.

Table 2: Opening RAB to apply to Ergon Energy ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB	4146.2	4662.4	5243.4	5858.1	6402.4
Actual net capex (adjusted for actual CPI and WACC)	622.1	720.2	654.5	686.8	833.9
Straight-line depreciation (adjusted for actual CPI)	–105.9	–139.3	–39.8	–142.4	–131.0
Closing RAB	4662.4	5243.4	5858.1	6402.4	7105.4
Opening RAB at 1 July 2010					7105.4

(a) Based on estimated net capex.
(b) Based on estimated net capex and a forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.

Demand forecasts

Qld DNSP regulatory proposals

Energex

Energex based its capex program on 50 per cent probability of exceedence (PoE) maximum demand and customer number forecasts. Energex forecast maximum demand using both a bottom up method, based on internally produced forecasts of maximum demand at zone substation level, and a top down method based on key drivers. Energex identified the following key drivers of maximum demand and energy consumption on its network:

- customer number growth and distribution patterns
- economic growth in south east Queensland
- climate considerations
- the impact of air conditioner use
- the projected impact of demand management strategies.

Energex’s forecasts of maximum demand, customer numbers and energy consumption are set out in table 3.

Table 3: Energex proposed maximum demand, customer numbers and energy consumption

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15
Maximum demand (50% PoE) – MW	5126	5338	5633	5844	5941	2.6%
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294	2.1%
Energy consumption – GWh	22 416	23 138	24 042	24 795	25 845	3.0%

Ergon Energy

Ergon Energy forecast maximum demand on its network for the next regulatory control period using a bottom up method based on internally produced forecasts of maximum demand at the bulk supply point and zone substation levels of its network. Ergon Energy used spatial maximum demand forecasts to identify where it needed to augment individual components of its distribution system. Ergon Energy identified the following key drivers of maximum demand and energy consumption on its network:

- population growth

- major new industry and commercial development
- economic growth
- climate effects and air conditioner penetration.

Ergon Energy's forecasts of maximum demand, customer numbers and energy consumption are in table 4.

Table 4: Ergon Energy maximum demand, customer number and energy consumption

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15
Maximum demand (50% PoE) – MW	2967	3063	3153	3243	3330	3.1%
Customer numbers	684 469	695 242	706 204	717 356	728 706	1.6%
Energy consumption – GWh	15 871	16 450	16 874	17 433	17 887	3.9%

AER conclusion

Energex

The AER accepts Energex's forecasts of customer numbers and energy consumption.

The AER reviewed Energex's proposed demand forecasts and considers that the maximum demand forecasts proposed by Energex do not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER. The AER considers that reducing Energex's forecast maximum demand to the levels shown in table 5 provides a more realistic basis for determining capex and opex forecasts.

Table 5: AER conclusion on Energex's maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand (MW)	4864	5027	5228	5466	5684
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294
Energy consumption (GWh)	22 416	23 138	24 042	24 795	25 845

Ergon Energy

The AER accepts Ergon Energy's forecasts of customer numbers.

The AER reviewed Ergon Energy's proposed demand forecasts and considers that the maximum demand and energy consumption forecasts proposed by Ergon Energy do not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER. The AER considers that reducing Ergon Energy's forecast maximum demand to the levels shown in table 6 provides a more realistic basis for determining capex and opex forecasts.

Table 6: AER conclusions on Ergon Energy's maximum demand and customer number forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand (MW)	2693	2811	2928	3031	3121
Customer numbers	684 469	695 242	706 204	717 356	728 706

The AER notes that energy consumption forecasts are not relevant in the determination of Ergon Energy's revenue cap. However, energy consumption forecasts are an important input to the development of Ergon Energy's network prices. The AER therefore requires Ergon Energy to review its energy consumption forecasts before submitting its pricing proposal to the AER for approval in 2010.

Forecast capital expenditure

Qld DNSP regulatory proposals

Energex

Energex proposed a capex allowance totalling $6466 million ($2009–10) for the next regulatory control period. Table 7 shows Energex's capex proposal.

Table 7: Energex proposed capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Growth	416.7	457.0	533.0	569.3	637.2	2613.2
Asset replacement/renewal	160.5	255.7	212.9	280.2	256.0	1165.3
Reliability and quality of service enhancement	85.8	50.6	72.6	51.6	45.7	306.3
Security compliance	384.0	381.6	385.0	328.1	338.6	1817.3
Non-system capex	192.3	124.8	98.4	63.2	85.0	563.7
Total capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0

Note: Totals may not add due to rounding.

Ergon Energy

Ergon Energy proposed capex of $6033 million ($2009–10) for the next regulatory control period. Table 8 shows Ergon Energy's capex proposal.

Table 8: Ergon Energy proposed capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement	177.4	212.7	250.0	274.8	299.2	1214.1
Corporation initiated augmentation (growth capex)	267.8	339.4	401.3	463.6	518.9	1990.9
Customer initiated capital works (growth capex)	336.1	355.0	315.6	328.7	359.6	1695.0
Reliability and quality improvements	18.3	20.9	24.5	28.3	30.4	122.4
Other system capex	105.6	72.9	50.8	50.4	51.7	331.4
Non-system capex	180.9	199.0	135.2	82.3	81.7	679.1
Total capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9

Note: Totals may not add due to rounding.

AER conclusion

To assess the Qld DNSPs' forecast capex proposals the AER reviewed:

- the Qld DNSPs' governance frameworks, capex policies and procedures
- the methods used to develop the capex proposals, including planning processes, demand forecasts and network planning criteria
- the need for the projects proposed in the regulatory proposals and whether the scope, timing and costs were efficient
- the cost estimation processes employed by the Qld DNSPs
- the deliverability of the forecast capex programs.

Energex

The AER is satisfied that Energex has capex planning and governance processes consistent with the achievement of the capex objectives. The AER considered Energex's proposed forecast capex allowance of $6466 million and is not satisfied that Energex's forecast capex reasonably reflects the capex criteria in the NER. In coming to this view the AER has had regard to the capex factors.

The AER is not satisfied that Energex's growth capex or proposed cost escalators adequately account for the GFC. Revisions to Energex's capex allowance mostly relate to these factors. Further the AER considers that Energex's proposed non–system capex on major building projects has not been demonstrated to be prudent and efficient.

Following its review of Energex's capex proposal the AER has made the following adjustments:

- $372 million reduction to total capex, applied across all components of forecast capex, to account for revisions in the escalation of real input costs

- $289 million reduction to growth capex to reflect expected slower growth in economic activity

- $158 million reduction to non–system capex to exclude unsupported proposed expenditure on major building projects

- $7 million reduction in indirect costs associated with the ICT services that do not reasonably reflect the capex criteria, including the capex objectives.

Following the adjustments outlined above, and as detailed in table 9, the AER is satisfied an estimate of $5718 million for Energex's forecast capex reasonably reflects the capex criteria, taking into account the capex factors. The AER considers this reduction is the minimum adjustment necessary to ensure Energex's capex forecast meets the capex criteria.

Table 9: AER conclusion on Energex's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0
Adjustment to growth capex	–37.3	–43.8	–60.5	–66.9	–80.0	–288.6
Adjustment to non–system capex	–105.0	–32.7	–20.6	0.0	0.0	–158.3
Adjustment to indirect costs	–0.5	–1.7	–1.6	–1.3	–1.7	–6.8
Re-inclusion of indirect costs that were included in growth capex and non–system capex deductions	19.7	14.3	15.7	12.8	15.1	77.7
Adjustment to cost escalators	–51.6	–61.2	–75.6	–85.1	–98.2	–371.7
AER capex allowance	1064.8	1144.6	1159.3	1151.9	1197.7	5718.3

Notes: Totals may not add due to rounding.
The indirect costs included in deductions to growth and non–system capex should not be removed from Energex's capex allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Energex's indirect costs.

Ergon Energy

The AER considers that Ergon Energy's capex planning and governance processes are generally appropriate and provide adequate assurance that investment decisions are likely to be prudent and efficient. The AER considered Ergon Energy's proposed forecast capex allowance of $6033 million and is not satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria in the NER. In coming to this view the AER has had regard to the capex factors.

The AER does not consider that Ergon Energy's proposed growth capex reflects a realistic expectation of the demand forecast required to achieve the capex objectives. The AER considers that Ergon Energy's proposed asset replacement capex does not reflect efficient costs.

The AER also considers that Ergon Energy's proposed reliability and quality improvement capex, in particular the feeder improvement program, has not been demonstrated to be prudent and efficient.

Further the AER considers the expenditure associated with Ergon Energy's major building projects and the information and communications technology (ICT) systems change program has not been demonstrated to be prudent and efficient.

Following its review of Ergon Energy's capex proposal the AER has made the following adjustments:

- $844 million reduction to growth capex to reflect a realistic expectation of demand and a revised approach to forecasting customer initiated capital works expenditure
- $119 million reduction to asset replacement capex to reflect a business as usual approach to forecasting expenditure in this category
- $35 million reduction to reliability and quality improvement capex to exclude expenditure associated with the feeder improvement program and reflect a revised level of expenditure based on outcomes in the current regulatory control period plus additional expenditure for the SCADA acceleration program
- $39 million reduction in shared costs associated with the ICT services, sponsorship and community engagement that do not reasonably reflect the capex criteria, including the capex objectives
- $253 million reduction to non–system capex to exclude ICT systems expenditure associated with the change program and unsupported expenditure on major building projects
- $82 million increase to total capex, applied across all components of forecast capex, to account for errors in the application of input cost escalators.

Following the adjustments outlined above, and as detailed in table 10, the AER is satisfied an estimate of $5013 million for Ergon Energy's forecast capex reasonably reflects the capex criteria, taking into account the capex factors. The AER considers this reduction is the minimum adjustment necessary to ensure Ergon Energy's capex forecast meets the capex criteria.

Table 10: AER conclusion on Ergon Energy's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9
Adjustment to growth capex	–155.1	–179.5	–140.9	–168.2	–200.5	–844.2
Adjustment to asset replacement capex	–9.9	–19.4	–30.9	–30.0	–28.6	–118.8
Adjustment to reliability and quality improvement capex	–2.6	–4.5	–7.1	–9.8	–11.4	–35.3
Adjustment to non–system capex	–95.6	–115.7	–50.6	1.7	6.6	–253.5
Adjustment to shared costs	–2.2	–5.9	–9.2	–9.8	–11.5	–38.6
Re-inclusion of shared costs that were included in growth, asset replacement, reliability and non–system capex deductions	40.6	48.3	36.0	30.6	32.6	188.1
Adjustment to cost escalators	–16.2	2.0	22.2	37.6	36.5	82.1
AER capex allowance	845.4	925.2	996.8	1080.0	1165.3	5012.8

Notes: Totals may not add due to rounding.
The shared costs included in deductions one to four above are not to be removed from Ergon Energy's capex allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Ergon Energy's shared costs.

Forecast operating expenditure

Qld DNSP regulatory proposals

Energex

Energex proposed an opex forecast of $1843 million ($2009–10) for the next regulatory control period, $214 million (13 per cent) more than its expected opex in the current regulatory control period. Table 11 sets out Energex's forecast opex for the next regulatory control period.

Table 11: Energex proposed opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Total controllable opex	324.5	330.0	340.4	351.7	349.2	1695.7
Self insurance	2.8	2.9	3.1	3.2	3.0	15.1
Debt raising costs	7.2	8.1	9.0	9.9	10.7	44.8
Equity raising costs	20.6	19.8	18.8	15.7	12.6	87.4
Total opex	355.1	360.9	371.3	380.4	375.5	1843.1

Ergon Energy

Ergon Energy proposed an opex forecast of $1993 million ($2009–10) for the next regulatory control period, $459 million (30 per cent) more than its expected opex in the current regulatory control period. Table 12 sets out Ergon Energy's forecast opex for the next regulatory control period.

Table 12: Ergon Energy proposed opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Total controllable opex	365.9	377.3	381.2	382.3	370.2	1876.9
Self insurance	4.2	4.2	4.3	4.4	4.5	25.1
Debt and equity raising costs[a]	11.9	16.3	22.0	22.8	21.2	94.1
Total opex	382.0	397.8	407.5	409.5	395.9	1992.6

Note: Totals may not add due to rounding.

(a) Ergon Energy's PTRM includes an amount of $94.1 million for debt and equity raising costs. Ergon Energy has used an incorrect input which it sought for debt raising costs in the revenue modelling.

AER conclusion

Energex

The AER is satisfied that Energex's methodology for establishing its forecast opex is sound. The AER considered Energex's forecast opex of $1843 million ($2009–10) and is not satisfied that the total opex forecast proposed by Energex reasonably reflects the opex criteria, including the opex objectives of the NER. In coming to this view the AER has had regard to the opex factors. In establishing its opex allowance the AER has taken account of the following adjustments:

- $2.2 million reduction to demand management
- $11 million reduction to other support costs
- $2.2 million reduction to ICT overheads
- $19 million reduction to debt raising costs
- $87 million reduction to equity raising costs
- $15 million reduction to self insurance costs
- $140 million reduction to total opex to reflect the impact of revised input cost escalators.

Based on its analysis of Energex's regulatory proposal, the advice of PB and other information, the AER has applied a reduction of $257 million to Energex's proposed opex forecast. This represents a reduction of around 14 per cent of Energex's proposed opex and results in a revised opex forecast of $1586 million ($2009–10) for the next regulatory control period. This reduction is mostly a consequence of expected reductions in input costs and other adjustments to non-controllable opex claims. The

AER considers this reduction is the minimum adjustment necessary to ensure Energex's proposed opex forecast meets the opex criteria. The AER's conclusion on Energex's opex by category is illustrated in table 13.

Table 13: AER conclusion on Energex's total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex's controllable opex forecast	324.5	360.8	340.4	351.6	349.2	1695.7
Self insurance costs	2.8	2.9	3.1	3.2	3.0	15.1
Debt raising costs	7.2	8.1	9.0	9.9	10.7	44.8
Equity raising costs	20.6	19.8	18.8	15.7	12.6	87.4
Energex's total opex	355.1	360.9	371.3	380.4	375.5	1843.1
AER's controllable opex (including input cost escalators)	303.6	303.7	308.7	315.4	308.7	1540.1
Self insurance costs	0.0	0.0	0.0	0.0	0.0	0.04
Debt raising costs	4.2	4.6	5.1	5.5	6.0	25.3
Equity raising costs[a]	–	–	–	–	–	–
Reinclusion of overheads removed in AER controllable opex[b]	5.4	3.8	4.2	3.5	4.0	20.9
AER total opex	313.2	312.2	318.0	324.4	318.7	1586.3

Note: Totals may not add due to rounding.

(a) The AER will allow Energex to amortise a total of $36.8 million ($2009–10) for benchmark equity raising costs for the next regulatory control period.

(b) The indirect costs included in the AER's adjustments to opex are not to be removed from Energex's opex allowance. This is because, with the exception of an adjustment for ICT services and sponsorship costs, the AER has not proposed any adjustments to Energex's indirect costs.

Ergon Energy

The AER is mostly satisfied that Ergon Energy's methodology for establishing its forecast operating costs is sound. The AER considered Ergon Energy's forecast opex of $1993 million ($2009–10) and is not satisfied that Ergon Energy's opex forecast reasonably reflects the opex criteria, including the opex objectives, in the NER. In coming to this view the AER has had regard to the opex factors. In establishing its opex allowance the AER has taken account of the following adjustments:

- $33 million reduction to preventative maintenance
- $14 million reduction to corrective maintenance
- $7 million reduction to forced maintenance
- $53 million reduction to vegetation management

- $84 million reduction to other opex
- $6.4 million reduction to ICT overheads
- $21 million reduction to self insurance
- $72 million reduction to debt raising and equity raising costs
- $264 million reduction to opex to reflect the impact of revised input cost escalators.

Based on its analysis of Ergon Energy's regulatory proposal, the advice of PB and other information, the AER has applied a reduction of $479 million to Ergon Energy's opex forecast. This represents a reduction of around 24 per cent of Ergon Energy's proposed opex and results in a revised forecast opex allowance of $1514 million ($2009–10) for the next regulatory control period. The AER considers this reduction is the minimum adjustment necessary to ensure Ergon Energy's proposed opex forecast meets the opex criteria. The AER's conclusion on Ergon Energy's opex by category is illustrated in table 14.

Table 14: AER conclusion on Ergon Energy's total opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy controllable opex forecast	365.9	377.3	381.2	382.3	370.2	1876.9
Self insurance costs	4.2	4.2	4.3	4.4	4.5	21.5
Debt and equity raising costs	11.9	16.3	22.0	22.8	21.1	94.1
Ergon Energy total opex	382.0	397.8	407.5	409.5	395.8	1992.6
AER controllable opex (including input cost escalation and reinstated shared costs)[a]	316.7	315.2	300.4	288.9	271.0	1492.1
Self insurance costs	0.0	0.0	0.0	0.0	0.0	0.016
Equity raising costs[b]	–	–	–	–	–	–
Debt raising costs	3.8	4.0	4.4	4.7	5.1	22.0
AER total opex	320.5	319.2	304.8	293.6	276.1	1514.2

Note: Totals may not add due to rounding.

(a) The shared costs included in the AER's deductions to opex are not to be removed from Ergon Energy's opex allowance. This is because, with the exception of an adjustment for ICT services and sponsorship costs, the AER has not proposed any adjustments to Ergon Energy's shared costs.

(b) The AER will allow Ergon Energy to amortise a total of $11.9 million ($2009–10) for benchmark equity raising costs for the next regulatory control period.

Estimated corporate income tax

Qld DNSP regulatory proposals

The level of imputation credits (gamma) is an input to the post–tax revenue model (PTRM), and is used to derive an estimate of corporate income tax. The Qld DNSPs proposed a gamma of 0.2.

Energex did not accept the gamma of 0.65 from the AER's statement of regulatory intent regarding WACC parameters (SORI) as it did not consider it to be reasonable based on current market evidence. Ergon Energy argued that the AER, in determining a value of 0.65 in the SORI, did not give sufficient weight to the evidence before it.

The Qld DNSPs proposed allowances for tax calculated by the PTRM, in accordance with the methodology set out in the NER. The allowance for tax is an output of the PTRM rather than an input to be specified or proposed by the regulated business.

The Qld DNSPs' proposed tax asset bases as at 1 July 2010 are:

- Energex – $3759 million
- Ergon Energy – $4000 million.

AER conclusion

The AER assessed each of the inputs to the PTRM that are used to calculate the expected cost of corporate income tax.

The AER considers the Qld DNSPs' regulatory proposals and the supporting information provided do not constitute persuasive evidence to justify a departure from a gamma of 0.65, as specified in the SORI. In forming its view the AER has considered the information provided by interested parties in response to the gamma determined in the SORI and considered it against its underlying criteria.

The AER considers that the Qld DNSPs' proposed tax remaining and tax standard asset lives are appropriate. The AER also considers the Qld DNSPs' proposed opening tax asset bases to be appropriate and reasonable. Using these inputs, the AER used the PTRM to calculate the allowance for corporate income tax, as set out in table 15.

Table 15: AER conclusion on corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	32.2	35.5	39.1	43.0	45.9	195.7
Ergon Energy	0.0	20.1	29.3	34.0	33.1	116.5

Note: Ergon Energy has no tax allowance for 2010–11 due to the carry forward of tax losses from previous years.

Depreciation

Qld DNSP regulatory proposals

The Qld DNSPs proposed to use the straight-line approach to calculating depreciation in the PTRM. The Qld DNSPs proposed the regulatory depreciation allowances set out in table 16.

Table 16: Qld DNSPs proposed regulatory depreciation allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	87.1	96.4	108.0	119.5	120.6	531.6
Ergon Energy	103.4	116.8	113.7	130.5	134.3	598.6

In addition, Ergon Energy proposed that its assets destroyed by Cyclone Larry in March 2006 be subject to accelerated depreciation.

AER conclusion

The AER assessed the remaining asset lives and standard asset lives used by the Qld DNSPs as inputs to their PTRMs, and the resulting regulatory depreciation allowances.

The AER accepts Energex's remaining asset lives. The AER does not accept the remaining asset lives proposed by Ergon Energy due to an error which had a significant impact on Ergon Energy's depreciation allowance. The AER accepts the standard asset lives proposed by the Qld DNSPs.

The AER also accepts Ergon Energy's claim for accelerated depreciation, although the amount to be recovered has been revised to reflect the changes in the calculation of remaining assets lives.

On the basis of the AER's approved asset lives, opening RAB, and forecast capex allowance, the AER has determined the Qld DNSPs' regulatory depreciation allowances for the next regulatory control period, as set out in table 17.

Table 17: AER conclusion on regulatory depreciation allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	87.1	97.2	108.9	120.6	121.7	535.6
Ergon Energy	151.0	158.3	157.9	171.4	152.2	790.8

Note: These depreciation allowances include equity raising costs that are to be amortised, rather than expensed as the Qld DNSPs had proposed.
The depreciation allowance for Ergon Energy does not include its accelerated depreciation claim for destroyed assets. The assets are accounted for separately in the PTRM.

Cost of capital

Qld DNSP regulatory proposals

The Qld DNSPs proposed a nominal WACC of 9.49 per cent, based on 10–year Commonwealth government securities (CGS) yield at the time the proposal was prepared.

The parameters proposed by the Qld DNSPs are shown in table 18. The proposed methods, values, parameters and credit ratings are consistent with the SORI, with the exception of the nominal risk-free rate.

Table 18: Qld DNSPs proposed WACC parameters

Parameter	Energex	Ergon Energy	SORI
Nominal risk-free rate[a]	Yield on CGS plus 79 bps convenience yield 5.08%	Yield on CGS plus 79 bps convenience yield 5.08%	Nominal risk-free rate (no convenience yield)
Gearing level (Debt/Equity)	60:40	60:40	60:40
Market risk premium	6.50%	6.50%	6.50%
Equity beta	0.80	0.80	0.80
Credit rating level	BBB+	BBB+	BBB+
Debt risk premium[a]	3.88%	3.88%	N/A
Expected inflation rate[a]	2.45%	2.45%	N/A
Nominal vanilla WACC[(a)]	9.49%	9.49%	N/A

(a) Indicative only, these parameter values are to be updated in the final decision.

The Qld DNSPs proposed a nominal risk-free rate equal to the annualised yield on nominal CGS with a maturity of 10 years plus a convenience yield of 0.79 per cent per annum. The Qld DNSPs stated that the return on equity provided in their regulatory proposals, due to their proposed nominal-risk free rate, is more reasonable than the return on equity based upon the methods and values used in the SORI.

The Qld DNSPs proposed an indicative debt risk premium (DRP) of 3.88 per cent, noting that this figure would be updated for the final determination with data from the agreed averaging period. Both accepted the use of a BBB+ credit rating and proposed that the DRP be derived from a simple average of Bloomberg and CBASpectrum fair value estimates of the cost of debt.

AER conclusion

The SORI defines a number of the WACC parameter values to be adopted by the Qld DNSPs for the purposes of setting a rate of return, unless there has been a material change in circumstances. For the parameters where the values are calculated based upon a method—nominal risk-free rate and the DRP—the SORI sets out the method to be used by the AER for determining the values.

The AER has calculated an indicative nominal vanilla WACC of 10.06 per cent. The indicative WACC provided for in the draft decision is higher than that proposed by the Qld DNSPs because the risk–free rate and DRP have increased since the time the DNSPs prepared their proposals. The WACC determined by the AER does not include a proposed convenience yield.

Table 19 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and DRP, based on the agreed averaging period, and the expected inflation rate at a time closer to the final Qld DNSPs' distribution determinations.

Table 19: AER conclusion on WACC parameters

Parameter	Energex	Ergon Energy
Nominal risk-free rate	5.44%	5.44%
Real risk-free rate	2.92%	2.92%
Expected inflation rate	2.45%	2.45%
Gearing level (Debt/Equity)	60:40	60:40
Market risk premium	6.5%	6.5%
Equity beta	0.80	0.80
Debt risk premium	4.24%	4.24%
Nominal pre-tax return on debt	9.68%	9.68%
Nominal post-tax return on equity	10.64%	10.64%
Nominal vanilla WACC	10.06%	10.06%

Service target performance incentive scheme

Qld DNSP regulatory proposals

Energex

Energex proposed that the AER apply the STPIS as set out in the framework and approach subject to the following variations:

- the STPIS should take the form of a paper trial in the first year of the next regulatory control period; be capped at ±1 per cent in the second year; and be fully implemented—that is, apply a cap of ±2 per cent revenue at risk, from the third year of the next regulatory control period
- the STPIS should exclude the telephone answering parameter because of unreliable data for the first two years of the next regulatory control period
- the value of customer reliability values should be based on the STPIS guideline (version 01.0) with the same value for each of the reliability network segments.

Ergon Energy

Ergon Energy proposed that the AER apply the STPIS as set out in the framework and approach paper.

AER conclusion

Energex

The AER has determined that the national distribution STPIS will apply to Energex in the next regulatory control period in the following form:

- the applicable component and parameters are the system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) reliability of supply parameters. The AER will not apply the telephone answering customer service parameter to Energex
- overall revenue at risk of ±2 per cent
- the incentive rates to apply to each applicable parameter are to be determined in accordance with clause 3.2.2 and appendix B of version 01.2 of the STPIS, as set out at table 12.4 of this draft decision
- that the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period as set out at table 12.6 of this draft decision
- the guaranteed service level (GSL) component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn the AER will implement such a scheme from the day the jurisdictional scheme is withdrawn.

Ergon Energy

The AER considers that the methodology proposed by Ergon Energy to set performance targets based on minimum service standards (MSS) targets is not appropriate. The AER set performance targets based on Ergon Energy's internal targets.

The AER has determined that the national distribution STPIS will apply to Ergon Energy in the next regulatory control period in the following form:

- the applicable component and parameters are the SAIDI and SAIFI reliability of supply parameters. The AER will also apply the telephone answering customer service parameter to Ergon Energy
- overall revenue at risk of ±2 per cent and ±0.2 per cent for the telephone answering parameter
- the incentive rates to apply to each applicable parameter are to be determined in accordance with clause 3.2.2 and appendix B of version 01.2 of the STPIS, as set out at table 12.5 of this draft decision

- that the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period as set out at table 12.7 of this draft decision
- the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn, the AER will implement such a scheme from the day the jurisdictional scheme is withdrawn.

Efficiency benefit sharing scheme

Qld DNSP regulatory proposals

The Qld DNSPs proposed that recognised pass through events and opex for non–network alternatives should be excluded for the purpose of calculating the EBSS.

Energex proposed the following costs be excluded from the EBSS:

- debt and equity raising costs
- insurance costs
- self insurance costs.

Ergon Energy proposed that the following costs be excluded from the EBSS:

- the demand management innovation allowance
- self insurance costs.

AER conclusion

The AER will apply its EBSS, released in June 2008, to the Qld DNSPs for the next regulatory control period. The AER will not adjust the EBSS for the consequences of changes in demand growth for the Qld DNSPs for the next regulatory control period.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period for the Qld DNSPs:

- debt raising costs
- insurance and self insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives, including the demand management innovation allowance.

These are in addition to the costs of pass through events which are excluded by the EBSS. Benchmark efficient equity raising costs have been amortised and therefore are not included as an opex category.

Demand management incentive scheme

Qld DNSP regulatory proposals

Energex accepted the application of a demand management incentive scheme in the form of the Part A – demand management innovation allowance, capped at $5 million for the next regulatory control period. However, it stated that this was subject to the AER accepting Energex's proposed demand management strategy and programs.

Ergon Energy accepted the application of a demand management incentive scheme in the form of the Part A – demand management innovation allowance, capped at $5 million for the next regulatory control period.

AER conclusion

The AER will apply Part A – demand management innovation allowance to the Qld DNSPs, as outlined in the AER's framework and approach paper. The demand management innovation allowance will be capped at $5 million for each DNSP in the next regulatory control period. The capped amount will be allocated as an ex-ante annual allowance of $1 million, for each year of the next regulatory control period.

The ex-post review and operation of the demand management innovation allowance will be as set out in the demand management incentive scheme.

Pass through arrangements

Qld DNSP regulatory proposals

Energex

Energex proposed the following events be nominated as specific nominated pass through events:

- feed-in tariff event
- smart meter event
- carbon pollution reduction scheme (CPRS) event
- occupational health and safety event
- Henry tax review event
- regulatory information order reporting event
- national electricity customer framework event
- national broadband network event
- guaranteed service level event
- storm disaster event.

Energex proposed the following events should be treated as general nominated pass through events:

- force majeure
- earthquakes above the magnitude of five
- compliance event/functional change/changes in reporting requirements
- distribution loss event
- electric magnetic fields event
- insurance event
- retailer of last resort
- joint planning event
- events for which self insurance allowances were rejected
- interim change events
- retailer credit risk event.

Energex proposed a materiality threshold of $200 000 for specific nominated events, commensurate with the cost of assessing the pass through application. Energex proposed that for general nominated pass through events, the materiality threshold should be defined as 1 per cent of average annual revenue or a fixed amount of $5 million, whichever is lower.

Ergon Energy

Ergon Energy proposed the following 'regulatory change' events:

- change to minimalist transitioning approach
- introduction of smart meters
- transfer of regulatory functions to a national regulatory framework
- introduction of an emissions trading scheme
- distribution losses
- network obligation in relation to electric and magnetic fields
- changes in reporting requirements
- changes in taxes or other levies.

Ergon Energy proposed the following events as nominated pass through events:

- force majeure
- change of business structure event (that is, externally imposed).

AER conclusion

The AER accepts the following nominated pass through events for the Qld DNSPs:

- smart meter event
- CPRS event
- feed-in tariff event
- a general nominated pass through event.

The AER does not consider that the other proposed pass through events meet the AER's assessment criteria and therefore those events are not accepted as nominated pass through events. In many instances the AER considers the proposed events are likely to be regulatory change events, or may fit the definition of a general nominated pass through event.

For general nominated events the AER will apply a materiality threshold of 1 per cent of the smoothed revenue allowance specified in the AER's final distribution determination for each of the years of the regulatory control period in which the costs are incurred. The AER will apply a materiality threshold of the administrative costs of assessing an application relating to specific nominated events.

Building block revenue requirements

Qld DNSP regulatory proposals

Energex

Energex's calculation of annual revenue requirements and X factors are summarised in table 20.

Table 20: Energex proposed annual revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation		87.1	96.4	108.0	119.6	120.6
Return on capital		748.5	863.5	983.8	1109.4	1234.7
Operating expenditure [a]		364.8	379.8	400.2	420.0	424.9
Tax allowance		83.05	92.10	101.95	112.44	120.76
Capital contributions		–64.6	–68.9	–70.9	–73.6	–75.7
Capital contributions under recovery 2008–09		1.2				
DUOS over recovery 2008–09		–48.6				
Tax over recovery 2008–09		–26.9				
Revenue from shared assets		–4.5	–5.3	–6.0	–6.5	–6.0
Annual revenue requirements		1140.1	1357.5	1517.1	1681.3	1819.3
Expected revenues	936.7	1202.7	1336.2	1484.5	1649.2	1831.5
Forecast CPI (%)		2.45	2.45	2.45	2.45	2.45
X factors[b] (%)		–25.34	–8.44	–8.44	–8.44	–8.40

(a) Includes demand management innovation allowance, self insurance, and equity and debt raising costs.
(b) Negative values for X indicate real price increases under the CPI–X formula.

Ergon Energy

Ergon Energy’s calculation of annual revenue requirements and X factors are summarised in table 21.

Table 21: Ergon Energy proposed annual revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation		103.4	116.8	113.7	130.5	134.3
Return on capital		664.1	763.0	874.9	987.74	1107.5
Operating expenditure [a]		391.3	417.6	438.2	451.1	446.7
Tax allowance		0.0	17.3	61.8	75.7	80.4
Capital contributions		–112.0	–121.2	–107.9	–117.5	–135.2
Revenue from shared assets		–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation		11.3				
Annual revenue requirements		1054.9	1190.1	1377.3	1524.0	1630.2
Expected revenues	845.2	1100.2	1213.9	1339.3	1477.6	1630.2
Forecast CPI (%)		2.45	2.45	2.45	2.45	2.45
X factors[b] (%)		–27.05	–7.69	–7.69	–7.69	–7.69

(a) Includes demand management innovation allowance, self insurance, and equity and debt raising costs.
(b) Negative values for X indicate real price increases under the CPI–X formula.

AER conclusion

The AER calculated the Qld DNSPs' revenue requirements and X factors based on its decisions regarding the building blocks.

Energex

The AER's draft decision results in a total revenue requirement for the next regulatory control period of $7158 million, compared to $7515 million proposed by Energex. The main reasons for this difference reflect the net effect of:

- removal of $748 million from Energex's forecast capex
- removal of $257 million from Energex's forecast opex
- a reduced allowance for tax, reflecting in part a higher gamma
- a reduced allowance for equity raising costs
- a higher WACC than proposed by Energex.

Table 22: AER conclusion on Energex's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	87.1	97.2	108.9	120.6	121.7
Return on capital[a]	793.8	901.4	1015.5	1133.2	1252.0
Operating expenditure[b]	320.8	327.8	341.9	357.4	359.7
Tax allowance	32.2	35.5	39.1	43.0	45.9
Capital contributions	–64.6	–68.9	–70.9	–73.6	–75.7
Revenue from shared assets	–4.5	–5.3	–6.0	–6.5	–6.0
Annual revenue requirements	1165.8	1288.7	1429.7	1575.1	1698.7
Expected revenues	1180.6	1294.2	1418.7	1555.2	1704.8
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–23.03	–7.00	–7.00	–7.00	–7.00

(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real price increases under the CPI–X formula.

Ergon Energy

The AER's draft decision results in a total revenue requirement over the next regulatory control period of $6364 million, compared to $6776 million proposed by Ergon Energy. The main reasons for this difference reflect the net effect of:

- removal of $1020 million from Ergon Energy's forecast capex
- removal of $479 million from Ergon Energy's forecast opex
- a reduced allowance for tax, reflecting in part a higher gamma
- a reduced allowance for equity raising costs
- the addition of $106 million to Ergon Energy's opening RAB as at 1 July 2005
- the correction of remaining asset lives, which has the effect of increasing the depreciation allowance
- a higher WACC than proposed by Ergon Energy.

Table 23: AER conclusion on Ergon Energy's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	151.0	158.3	157.9	171.4	152.2
Return on capital[a]	715.1	791.0	875.8	971.1	1077.4
Operating expenditure[b]	328.3	335.1	327.7	323.5	311.6
Tax allowance	0.0	20.1	29.3	34.0	33.1
Capital contributions	–112.0	–121.2	–107.9	–117.5	–135.2
Revenue from shared assets	–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation	10.4				
Annual revenue requirements	1089.6	1180.0	1279.4	1379.0	1435.7
Expected revenues	1096.6	1178.5	1266.5	1361.1	1462.8
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors [c] (%)	–26.63	–4.90	–4.90	–4.90	–4.90

(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real price increases under the CPI–X formula.

Alternative control services – street lighting services

Qld DNSP regulatory proposals

Energex

Consistent with the framework and approach paper, Energex proposed a price cap form of control based on a limited building block approach to apply to its street lighting services. It stated that where a non–standard street light asset is requested the incremental cost difference (between constructing the standard and non–standard asset) will be levied as a quoted service and therefore subject to a price cap to be developed using a formula based approach.

Ergon Energy

Ergon Energy identified three categories of street lighting services for the next regulatory control period:

- the provision of new street lighting assets (category one)
- the operation, repair, replacement and maintenance of street lighting assets (category two)
- the alteration and relocation of existing street lighting assets (category three).

Ergon Energy proposed to charge for street lighting service categories one and three as a quoted service and therefore subject to a price cap to be developed using a formula based (non–building block) approach. It stated that the defining characteristic of these service categories is that they are requested by an individual customer and therefore the service must be tailored to meet the customer's specific requirements hence a fixed price cannot be determined in advance based on forecast costs and volumes.

Consistent with the framework and approach paper, Ergon Energy proposed a price cap form of control based on a limited building block approach to apply to its category two street lighting services.

AER conclusion

Energex

The AER approved a price cap for Energex's street lighting services for the first regulatory year of the next regulatory control period, and a price path for the remaining regulatory years of the next regulatory control period.

Compliance with the price cap control mechanisms is to be demonstrated by Energex providing, as part of its pricing proposal, the capped price for street lighting services in the relevant regulatory year consistent with this draft decision.

Ergon Energy

The AER approved a price cap for Ergon Energy's street lighting services for the first regulatory year of the next regulatory control period, and a price path for the remaining regulatory years of the next regulatory control period. The AER requires Ergon Energy to provide a forecast capex allowance for new street lighting assets to be provided in the next regulatory control period as part of its revised regulatory proposal. This allowance is to be incorporated as part of the limited building block. The AER considers its classification of supply enhancement and rearrangements of network asset services as quoted services accurately captures Ergon Energy proposed treatment of its category 3 street lighting services as quoted services.

Compliance with the price cap control mechanisms is to be demonstrated by Ergon Energy providing, as part of its pricing proposal, the capped price for each street lighting service in the relevant regulatory year consistent with this draft decision.

Alternative control services – quoted and fee based services

Qld DNSP regulatory proposals

The Qld DNSPs proposed formula based (non-building block) price cap control mechanisms for quoted and fee based services, in accordance with the framework and approach paper.

The Qld DNSPs stated that as the scope of the work for each quoted service is not known prior to the service being undertaken, these services will be provided on a price on application basis. They stated that it was not possible to cap the price for individual quoted services as the scope of work, and therefore the cost, for each individual quoted service is not known prior to the service being undertaken.

The Qld DNSPs proposed to calculate the capped price for each fee based service for the first regulatory year of the next regulatory control period, and a price path for the remaining regulatory years of the next regulatory control period.

AER conclusion

The AER approves the formula proposed by Energex to derive the prices for quoted and fee based services after amendment to remove the profit margin component.

The AER approves the formula proposed by Ergon Energy to derive the prices for quoted and fee based services after amendment to remove the other costs component.

For quoted services, the AER has determined the capped price of providing the illustrative configuration of each individual quoted services in the first regulatory year of the next regulatory control period. The AER has also established a price path for each individual formula component. Compliance with the price cap control mechanism is to be demonstrated by each Qld DNSPs providing, as part of their pricing proposals, the capped price and its calculation for each illustrative configuration of each individual quoted service in the relevant regulatory year. The AER's approved prices for each quoted service illustrative configuration is set out in appendix N and O of this draft decision. The AER's approved prices do not represent a binding capped price for an individual quoted service due to variable nature of quoted services.

For fee based services, the AER has determined a capped price for individual service for the first regulatory year of the next regulatory control period and established a price path for each service. Compliance with the price cap control mechanism is to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the capped price for each individual fee based service in the relevant regulatory year consistent with appendix P of this draft decision. The AER's approved price represents a binding capped price for each fee based service as the size, scale and scope of each service is known in advance of the service being undertaken.

1 Introduction

1.1 Background

Under the National Electricity Law (NEL) and the National Electricity Rules[1] (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of certain electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market (NEM).

The Queensland Competition Authority (QCA) made the current regulatory determinations for Energex and Ergon Energy (the Qld DNSPs) for a five year period from 1 July 2005 to 30 June 2010 (the current regulatory control period) under the National Electricity Code, which has been replaced by the NER. These DNSPs own and operate the electricity distribution networks in Queensland.

The AER has made the draft decision and determinations according to the relevant requirements of chapter 6 of the NER and the transitional requirements for Queensland contained in chapter 11 of the NER. The AER's principal task is to set the revenues that the Qld DNSPs can recover or prices that the Qld DNSPs can charge from the provision of direct control services during the next regulatory control period (1 July 2010 to 30 June 2015).

On 30 June 2009 the Qld DNSPs submitted their regulatory proposals for the next regulatory control period to the AER. On 17 July 2009 the AER published these and its proposed negotiated distribution service criteria (NDSC) for the Qld DNSPs.

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:[2]

> …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, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

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1 The AER uses the version of the NER that is in effect on the date a regulatory proposal is lodged. For the purposes of this draft decision and distribution determinations for Energex and Ergon Energy, the relevant version of the NER is version 29, which was in effect on 30 June 2009.

2 NEL, section 7.

Further, the NEL specifies that in performing or exercising its regulatory functions or powers, the AER must ensure that the DNSP to which the determination applies and any affected registered participant are, in accordance with the NER:[3]

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

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

Section 7A of the NEL 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.

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and

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3 NEL, section 16.

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 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 Qld 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 NDSC for negotiated distribution services.

The 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 of the NER requires a building block determination to 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 6.7.5 of the NER requires that:

> (a) 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.

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.

Negotiated distribution service criteria

Clause 6.7.4 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 Transitional arrangements

Transitional arrangements have been included in the NER for the AER’s distribution determination for the Qld DNSPs. These arrangements are contained in clauses 11.16 and 11.26.2 of the NER and specify how various requirements in chapter 6 of the NER apply to the Qld DNSPs for the next regulatory control period. Each chapter highlights the transitional arrangements that are relevant to the matter discussed in that chapter.

The transitional provisions of the NER also provide for the continuation of ring fencing arrangements from the current regulatory control period.

1.3 Review process

The AER has reviewed the Qld DNSPs' regulatory proposals in accordance with the review process outlined in Part E of chapter 6 of the NER. To date, this process has involved:

- Pre–consultation—the AER consulted with the Qld DNSPs about the development of the regulatory information notice, pro forma templates and guidelines.

- Framework and approach (stage 1)—the AER consulted with the Qld DNSPs and interested parties about the development of a framework and approach paper, with respect to the classification of services and control mechanism. The framework and approach paper was published in August 2008, as required under clauses 6.8.1 and 11.16.6 of the NER.

- Framework and approach (stage 2)—the AER also consulted with the Qld DNSPs about the development of a framework and approach paper, with respect to the application of schemes. This second framework and approach paper was published in November 2008, as required under clause 6.8.1 and clause 11.16.6 of the NER.

- Cost allocation methods—in February 2009, the AER approved the cost allocation methods of the Qld DNSPs under clause 6.15.4 of the NER.

- Proposal—the Qld DNSPs submitted their regulatory proposals to the AER on 30 June 2009. The AER assessed the Qld DNSPs' proposals against chapter 6 of the NER and the AER's guidelines.

- Public consultation—on 17 July 2009, the AER published the Qld DNSPs' regulatory proposals and the AER's proposed negotiated distribution service criteria and called for submissions from interested parties. On 3 August 2009, the AER held a public forum in Brisbane on the Qld DNSPs' regulatory proposals, where each Qld DNSP gave a presentation.

- Submissions—the AER received 11 submissions on the Qld DNSPs' regulatory proposals and the AER's proposed negotiated distribution service criteria. The submissions are listed in appendix R.

- Assessment by technical experts—the AER engaged Parsons Brinckerhoff Strategic Consulting (PB) as a technical expert to advise it on a number of key aspects of the regulatory proposals.[4]

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4 PB 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.

- PB provided its advice to the AER based on its review. The AER considered this advice in making its draft distribution determination. The terms of reference guiding PB's review are set out as an appendix to its report.

- Assessment by demand forecast experts—the AER engaged McLennan Magasanik Associates (MMA) as a technical expert to advise in relation to demand forecasts.

- Additional technical advice—the AER engaged Energy and Management Services to provide the AER with technical and engineering advice throughout the review process.[5] Energy and Management Services assisted the AER in reviewing the technical aspects of material contained in the Qld DNSPs' proposals, submissions and PB's report.

- Other specialist advice—the AER also engaged Access Economics[6] to provide a forecast of Queensland and South Australian labour costs relevant to electricity distribution businesses. McGrathNicol Corporate Advisory was engaged to review elements of the tax asset bases for the post–tax revenue model.

- The AER's analysis and assessment of the Qld DNSPs' regulatory proposals, submissions and specialist advice is set out in this draft decision.

1.4 Structure of draft decision

The AER's consideration of the Qld DNSPs' regulatory proposals, proposed negotiating frameworks and the NDSC to apply are set out as follows:

- chapters 2 to 4 address the classification of services, arrangements for negotiation and the control mechanisms for standard control services

- chapters 5 to 11 relate to key elements of the building block calculation

- chapters 12 to 15 set out the relevant schemes and pass through arrangements

- chapter 16 sets out the annual building block revenue requirements for the next regulatory control period

- chapters 17 to 18 set out the control mechanisms for alternative control services and the AER's review of these services.

1.5 Overview of the Queensland electricity distribution networks

1.5.1 Energex

Energex's distribution network covers 25 000 square kms, and serves around 1.3 million customers. Energex's network consists of over 500 000 poles and more

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[5] Energy and Management Services is an engineering consulting firm.

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

than 50 000 km of line. Figure 1.1 is a map of the electricity network in Queensland, showing the area covered by Energex's distribution network.[7]

Figure 1.1: Energex distribution network

Source: Energex, *Regulatory proposal*, July 2009, p 43.

1.5.2 Ergon Energy

Ergon Energy's distribution network covers approximately 1.7 million square kms, and serves around 632 000 customers. Ergon Energy's network consists of over 939 000 poles and 146 000 km of line. Figure 1.2 is a map of the electricity network in Queensland, showing the area covered by Ergon Energy's distribution network.[8]

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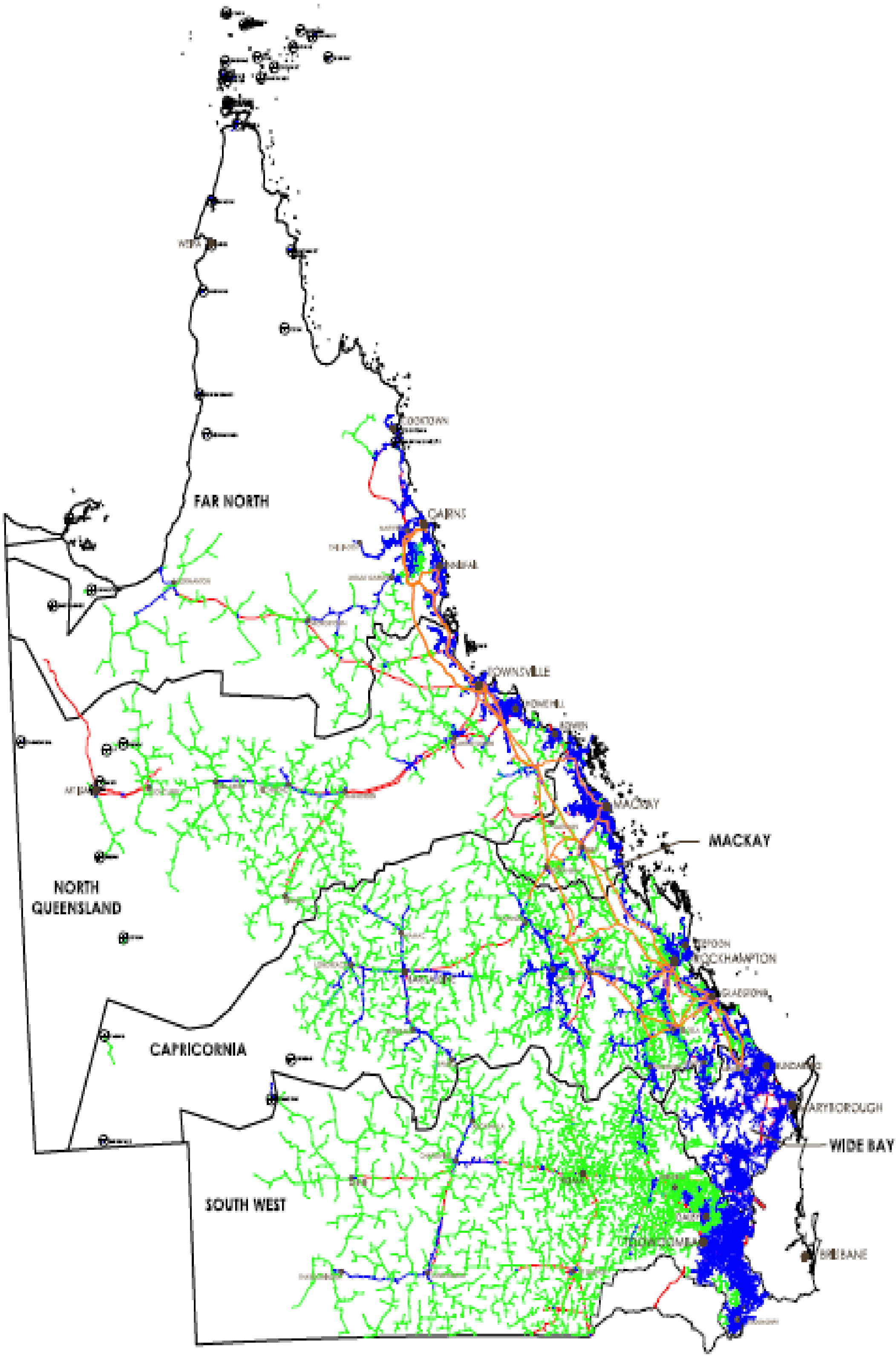
7 Energex, *Regulatory proposal for the period July 2010 – June 2015*, July 2009, p. 1.

8 Ergon Energy, *Regulatory proposal to the Australian Energy Regulator – 1 July 2010 to 30 June 2015*, 1 July 2009, p. 16.

Figure 1.2: Ergon Energy distribution network



Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 63.

2 Classification of services

2.1 Introduction

A distribution service is a service provided by means of or in connection with a distribution network, together with the connection assets, which is connected to transmission system or another distribution system.[9] Distribution services are classified as either direct control services, negotiated distribution services, or as unregulated distribution services.[10]

This chapter sets out the AER's classification of the Qld DNSPs' distribution services for the next regulatory control period. It draws on the AER's framework and approach paper for the Qld DNSPs.[11] The chapter also sets out the AER's decision on the procedures for assigning and re–assigning customers to tariff classes for direct control services.

2.2 Regulatory requirements

2.2.1 Classification of distribution services

Clause 6.2.1 of the NER allows the AER to classify a distribution service as either a direct control service or a negotiated distribution service. If the AER decides not to classify a distribution service, the service is not regulated under the NER. Under clause 6.2.2(a) of the NER, direct control services are categorised as either standard control services or alternative control services.

In its framework and approach paper, the AER set out its likely approach to the classification of distribution services for the Qld DNSPs' and its reasons for that approach.[12] Generally, the AER and the Qld DNSPs are not bound by these classifications.[13] If the AER considers that, in light of the regulatory proposal and submissions received, there are good reasons for departing from the classifications proposed in its framework and approach then it can do so.[14] The factors that guide the AER's decision on service reclassification are set out in clauses 6.2.1(c) and 6.2.2 of the NER.

2.2.2 Assigning customers to tariff classes

Under clause 6.12.1(17) of the NER, the AER must make a decision on the procedures for assigning and re–assigning customers to tariff classes for direct control services.

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9 NER, chapter 10.

10 NER, clause 6.2.1(a).

11 AER, *Final Decision, Framework and approach paper: Classification of services and control mechanism – Energex and Ergon Energy 2010–15*, August 2008.

12 The framework and approach paper must be prepared and published by the AER: NER, clause 6.8.1.

13 NER, clause 6.8.1(h).

14 NER, clause 6.12.3(b).

A DNSP is required to set out tariff classes as part of its pricing proposal. A DNSP's pricing proposal is submitted after the publication of the distribution determination under clause 6.18.1 of the NER. Clause 6.18.3 of the NER provides that separate tariff classes must be constituted for customers who are supplied with standard control services and alternative control services. The clause also requires that tariff classes be constituted with regard to the need to group customers together on an economically efficient basis and the need to avoid unnecessary transaction costs.

Clause 6.18.4(a) of the NER outlines the principles that the AER must have regard to when formulating procedures for the assignment or re-assignment of customers to tariff classes, including:

(1) customers should be assigned to tariff classes on the basis of one or more of the following factors:

(i) the nature and extent of their usage

(ii) the nature of their connection to the network

(iii) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement

(2) customers with a similar connection and usage profile should be treated on an equal basis;

(3) however, customers with micro–generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile;

(4) a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re–assign a customer from one tariff class to another should be subject to an effective system of assessment and review.

2.3 AER framework and approach

In its framework and approach the AER grouped the Qld DNSP's services and applied a classification for each group as shown in table 2.1.

Table 2.1: Qld DNSP service classification

Distribution service group	AER service classification
Network services	Standard control services
Connection services	Standard control services
Metering services	Standard control services
Street lighting services	Alternative control services
Quoted services	Alternative control services
Fee based services	Alternative control services
Unregulated	Unclassified

Source: AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008.

2.4 Queensland DNSP regulatory proposals

2.4.1 Classification of services

Energex

Energex submitted that its regulatory proposal has been prepared consistent with the AER's framework and approach classification of services.[15]

Ergon Energy

Ergon Energy submitted that it accepted the AER's framework and approach classification of services.[16]

2.4.2 Assigning customers to tariff classes

Energex

Energex stated that in line with clause 6.18.4(a) of the NER, its assignment of customers to tariff classes is determined based on the sequential assessment of the following criteria:

- energy consumption
- voltage level
- meter type
- demand
- for unmetered supply, whether the supply is for street lighting or other unmetered supplies.

[15] Energex, *Regulatory proposal*, July 2009, p. 94.
[16] Ergon Energy, *Regulatory proposal*, July 2009, p. 109.

Energex also stated that its procedures for assigning and reassigning customers to tariff classes reflects procedures published in its 2009–10 price schedule and is consistent with the requirements of clause 6.18.3 of the NER. It further stated that assignment of customers to network tariffs is reviewed periodically to assess the applicability of the tariff given potential changes in annual usage and meter type.[17]

Ergon Energy

Ergon Energy stated that it assigns customers to tariffs on the basis of geographical location, usage and size consistent with the requirements in clauses 6.18.4(a)(1) and 6.18.4(a)(2) of the NER. It also stated that it does not reassign customers without careful review and good reason.[18]

2.5 Submissions

2.5.1 Classification of services

SPA Consulting Engineers Qld (SPA) submitted that the AER should classify services in a manner that enables customers, where they are required to fund the cost of constructing network connection assets, to go to the market rather than be forced to use the DNSP to carry out the design and construction work. It also stated that a range of approval processes permit Ergon to use its monopoly position to restrict competition.[19] It specifically requested that the following works be categorised as either an alternative control service or a negotiated distribution service:[20]

- design and construction of underground/overhead electrical reticulation within and also headworks associated with underground urban residential, rural residential, industrial and commercial subdivision up to the point of the existing live high or low voltage assets

- design and construction of electrical reticulation within and also headworks associated with the relocation or expansion of a small or large customer network, as a customer requirement up to the point of connection to existing live high or low voltage assets.

Origin submitted that under the final framework and approach paper the AER's likely approach was to classify the variable costs of metering services as a standard control service for the next regulatory control period. It noted that the AER's final framework and approach classification for ETSA Utilities had classified the 'variable' cost of a standard small customer metering service as an alternative control service. Origin considered that the AER should adopt a similar classification for the Qld DNSPs for the next regulatory control period, primarily in recognition of the potential for competition to develop.[21]

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17 Energex, *Regulatory proposal*, July 2009, pp. 274–275.
18 Ergon Energy, *Regulatory proposal*, July 2009, pp. 443–446.
19 SPA, *Submission to the Australian Energy Regulator, Queensland distribution determination for the period 2010–15*, 28 August 2009, pp. 2–3.
20 SPA, *Submission to the AER*, August 2009, p. 3.
21 Origin, *Queensland electricity distributors regulatory proposals*, 28 August 2009, pp. 8–10.

2.6 Issues and AER consideration

2.6.1 Classification of services

The AER notes that both Qld DNSPs have proposed to classify services consistent with the final framework and approach.

Energex proposed to reclassify three services from alternative control to standard control service for the next regulatory control period.[22] Energex also stated that these services are classified as excluded services in the current regulatory control period but they are more appropriately classified as standard control services in the next regulatory control period.[23] The three services are:

- upgrade from overhead to underground
- provision of reactive power
- conversion to aerial bundle cables.

Energex's reason for this proposed change was that it was consequential to the AER's framework and approach classification decision. In that decision, the design and construction of large customer connections was classified as alternative control services. In the current regulatory control period this service is classified as a prescribed service. Energex considered that as a consequence of this classification change, the above three services' classification should also change.[24]

The AER notes that there is a clear presumption in the NER that the service classification must be consistent with the current classification unless a different classification is clearly more appropriate.[25] Energex has not addressed the matters listed in clause 6.2.2(c) of the NER to demonstrate why service classifications that depart from the current classifications are clearly more appropriate. In the absence of this, the AER is not able to assess the reasonableness of the proposed reclassifications. The AER therefore cannot reclassify these services and they remain as alternative control services.

Connection services

The matters raised by SPA were previously considered during the framework and approach process and addressed in the final decision made in August 2008. Relevantly, the final framework and approach paper stated:[26]

> Depending on the DNSP and the type of customer, design and construction of connection assets are currently provided in a competitive market up to the levels permitted by the DNSP, via service providers accredited and audited by the DNSPs. Stakeholders submitted that establishment and enforcement of technical standards should be undertaken by an independent body. The AER's

22 Energex, *Regulatory proposal*, July 2009, appendix 22.1, p. 3.
23 Energex, response to the AER question EGX.05.09, 21 August 2009, confidential.
24 Energex, response to the AER question EGX.05.09, 21 August 2009, confidential.
25 NER, clause 6.2.2(d).
26 AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008, p. 17.

> position paper noted that the establishment or enforcement of technical standards that rely solely on a DNSP's approval is not generally viewed as an appropriate function for the regulated entity to undertake. Stakeholders also noted delays related with connection services and requested that this issue be addressed.
>
> The AER's decision relates to the classification of services and control mechanisms under chapter 6 of the NER – economic regulation of distribution services. Therefore, the specifics and implementation of the non-economic regulatory framework that could underpin contestability is beyond the scope of this exercise. The AER also notes that matters related to delays in processing connection applications are covered by chapter 5 of the NER.

The AER recognises that in the other jurisdictions of the NEM contestability in the market for providing customer funded connections (including resulting extensions and augmentations) has been initiated by state regulatory arrangements.[27] This is not the case in Queensland.

Ergon Energy submitted that it is seeking to encourage greater competition in the provision of certain services including customer connections in the next regulatory control period.[28] However, in the absence of a state based regulatory arrangement, the AER notes that there is no requirement for a DNSP to allow contestability and customer choice is therefore constrained. Consequently, it appears that the number of Ergon Energy's customer funded connection services open to contestability lags behind that which Energex has made contestable in its geographical area. In this regard, the AER in its framework and approach paper noted that:[29]

> …the NER lists the matters that it [AER] must consider when making a classification decision. Whether assets have been externally funded or not is not a factor listed in the NER. Therefore, although the AER recognises the rationale for this submission it is not a factor that the AER must give weight to under the NER.

Clause 6.12.3 of the NER, describes the extent of the AER's discretion in making distribution determinations. Clause 6.12.3(b) states that unless there are good reasons to depart from the classifications proposed in its framework and approach the AER must apply the classifications set out in that paper. The AER considers that stakeholders have not raised any new matters that would cause it to depart from its classification and approach paper in this draft decision.

Metering services

Origin submitted that, similar to the ETSA Utilities framework and approach classification decision, the AER should classify the variable cost component of the standard small customer metering service as an alternative control metering service.[30]

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27 NSW—Section 31, of the *Electricity Supply Act, 1995 (NSW)*; South Australia—*Electricity Distribution Code*, section 3.4; and Victoria—Essential Services Commission, *Electricity Industry Guideline 14–provision of services by electricity distributors*, April 2004, section 4.

28 Ergon Energy, *Regulatory proposal*, July 2009, pp. 4–6.

29 AER, *Final framework and approach paper: Classification of services and control mechanism,* August 2008, p. 17.

30 See AER, *Draft decision, South Australia draft distribution determination*, 20 November 2009. The AER identified the quarterly meter read service (type 6) as the aspect of energy data services that is avoidable where ETSA Utilities ceases to provide the associated meter provision service.

The Qld DNSPs noted that Origin's submission on their service classification and control mechanism proposal in 2008 did not raise any concerns although type 5–7 metering services charges were proposed to be recovered via DUOS charges.[31]

The AER recognises that bundling of the standard small customer metering services with the DUOS charge could inhibit competition by creating a barrier to entry. Customers opting for a meter other than a type 5–7 meter from an alternative service provider continue to pay for the standard meter service as part of DUOS charges even though they no longer receive the standard service. This creates a barrier to entry for other metering service providers as customers effectively pay twice for their metering.

The AER's proposed classification of metering services provided by type 5–7 metering installations (both 'fixed' and 'variable' cost components) as a standard control service in its framework and approach is consistent with the QCA classification in the current regulatory control period.[32] Clause 6.2.2(d) requires the AER to classify direct control services consistent with the classification in the current regulatory period unless a different classification is clearly more appropriate.[33]

The AER considers that a key factor in moving services from standard control service to alternative control services is the potential for competition to develop. Ergon Energy stated that no premises within its geographical area that has a type 5–7 meter has had a retailer request that the meter be replaced by a type 4 meter and it does not expect this to change in the next regulatory control period.[34] Energex noted that small customers' enthusiasm for type 4 meters was uncertain.[35] Relative to the South Australian market at this time, the Queensland market has not sufficiently matured in that standard small customers appear not to be considering alternative non-standard meters. Given the maturity of the Queensland market at this time, the AER is not satisfied that there is sufficient potential for competition to develop in the provision of small customer metering in Queensland during the next regulatory control period.[36]

In the future the AER expects the Queensland metering services market to develop sufficiently to enable an alternative control service classification for small customer metering services. The AER will consider an appropriate methodology to collect information relating to standard small customer metering as part of the ongoing reporting requirements in the next regulatory control period (see appendix Q of this draft decision).

The AER acknowledges the on-going policy developments in the smart meter roll out[37] and considers that the policy outcome could have an impact on the extent the

31 Energex, response to the AER question EGX.16, 22 September 2009, confidential; and Ergon Energy response to the AER question ERG 17.1–8, 22 September 2009, confidential.
32 NER, clause 6.2.2(c)(3)
33 NER, clause 6.2.2(d).
34 Ergon Energy response to the AER question ERG 17.1–8, 22 September 2009, confidential.
35 Energex, response to the AER question EGX.16, 22 September 2009, confidential.
36 NER, clause 6.2.2(c) (1).
37 MCE, *Statement of Policy Principles*, June 2008, clause 3.

costs of meter provision services to small customers are directly attributable to the user in the next regulatory control period.[38]

The AER must have regard to the possible administrative costs for stakeholders, including DNSPs, in its classification of services.[39] The Qld DNSPs have both raised concerns relating to the administrative costs associated with a classification change and noted that a change at the draft decision stage will also require some fundamental changes to its regulatory proposal.[40] Given that the AER is not satisfied about the potential for competition to develop in the next regulatory control period, it considers that in this instance the effect of its classification decision on administrative costs of the Qld DNSPs should be given significant weight.

The AER notes that metering services have been classified in other jurisdictions as follows:

- The NSW distribution determinations were made under the transitional chapter 6 rules of the NER. These transitional rules did not provide for a separate assessment of this aspect under chapter 6 of the NER. In the NSW distribution determination the AER supported greater contestability in the provision of metering services. It noted Origin's submission requesting that the metering services variable costs should be unbundled from the DUOS charge. However, given the absence of a framework and approach process and the limited time available to make a proper assessment the AER did not consider it appropriate to change the classification.[41]

- The AER's framework and approach for the Victorian DNSPs did not classify metering services for customers with annual electricity consumption of 160 MWh or less. The regulation of charges for these services are subject to the *Victorian Advanced Metering Infrastructure Order in Council*, dated 25 November 2008.[42] The AER notes that in the current regulatory control period the Victorian DNSPs' standard metering services for small customers are comparable to an alternative control service classification given that charges for these metering services (prescribed metering services) were set separate to the DUOS charges.[43]

- The AER's draft distribution determination for ETSA Utilities has continued its classification of standard small customer metering services consistent with its framework and approach. Having considered the regulatory proposal and submissions received, it concluded that there were no good reasons for departing

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38 NER, clause 6.2.2(c)(5).

39 NER, clause, 6.2.2(c)(2).

40 Energex, response to the AER question EGX.16, 22 September 2009, confidential; Ergon Energy, response to the AER question ERG 17.1–8, 22 September 2009, confidential.

41 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14,* 28 April 2009, p. 22.

42 AER, *Final Framework and approach paper, Victorian electricity distribution regulation, Citipower, Powercor, jemena, SP AusNet and Uniting Energy, regulatory control period commencing 1 january 2011*, May 2009, p. 3.

43 ESC, *Final framework and approach paper: Volume 1, Guidance paper*, June 2004, p. 138; and *Electricity distribution price review, Final decision Volume 1*, October 2006, p. 510.

from the classification of services set out in its framework and approach.[44] That is, 'fixed' standard small customer metering services (type 6) were classified as standard control services and 'variable' standard small customer metering services (type 6) as an alternative control service.

The AER recognises that although there is some inconsistency between jurisdictions these are due to specific circumstances that preserved the presumption in favour of the prior classification and varying levels of market maturity in the provision of metering services. In the absence of these circumstances and given the AER's commitment to greater competition, a consistent classification of metering services in all four jurisdictions would have been achievable.[45]

Clause 6.12.3(b) of the NER requires the AER to continue its classifications as set out in its framework and approach unless there are good reasons for departing from it. The AER has had regard to the matters listed in clause 6.2.2(c) of the NER, and considers that there is no reason to depart from the classification of metering services as set out in its framework and approach.

List of distribution services

The Qld DNSPs provided a list of individual services that fall within each separate distribution service group determined by the AER in its framework and approach. The AER is satisfied that the individual services that the DNSPs propose to undertake in the next regulatory control period have been allocated to the appropriate service group. Appendix A to this draft decision sets out the Qld DNSPs' individual services and its service group along with the service classification.

2.6.2 Assigning customers to tariff classes

The AER notes clause 6.12.1(17) of the NER which requires the AER's distribution determination be predicated on the AER's decision on the procedures for assigning or reassigning customers to tariff classes as part of its distribution determination. There is no requirement on the Qld DNSPs to propose such procedures and consequently the AER must develop the required procedure.

Clause 6.18.4 of the NER specifies the principles that the AER must consider in formulating procedures for the assignment or reassignment of customers.

The Qld DNSPs responded to the AER's information requests and identified their respective documents setting out this internal system of assigning/reassigning customers to tariff classes.[46]

The AER notes that Energex's *Tariff Schedule 2009–10* recognises the customer's right to object and specifically states that it will undertake a review of its decision upon receipt of a written objection.[47] Ergon Energy's *Network use of system tariff*

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44 AER, *Draft decision*, *South Australia draft distribution determination*, 20 November 2009, p.17.
45 NER, clause, 6.2.2(c)(4).
46 Energex, response to the AER question EGX.11, 10 September 2009, confidential; Ergon Energy, response to the AER question ERG 12.01, 11 September 2009, confidential.
47 Energex, *Tariff schedule 2009–10*, p.5. Available at: <www.energex.com.au/network/network_prices/pdf/Tariff_schedule>.

guide states that it may determine that the network tariff should be changed (other than as a result of a request) due to changed circumstances.[48] However, Ergon Energy's tariff guide or its pricing principles statement does not explicitly recognise the customer's right to object nor does it state that it will undertake a review of its decision upon receipt of an objection.

The AER considers that an effective internal review system should clearly set out the process of escalation and, be visible and transparent to users. A well documented transparent system is necessary for an effective system of review.

An effective system of assessment and review under clause 6.18.4(a)(4) may, apart from providing for internal review, also include an effective external system of review as the next step in the process of escalation. The assignment or reassignment of a customer to a tariff class has a direct impact on the price the customer will be charged for direct control services. Customers dissatisfied by a decision of the internal review process should have access to the external review body. In the AER's NSW distribution determinations the AER recognised the NSW Water and Energy Ombudsman as the external review body for small retail customers.[49]

In the event of a dispute between a DNSP and a customer about assignment or reassignment of a customer to a tariff class, such dispute may be able to be referred to the AER in accordance with Part 10 of the NEL and clause 6.22.1 of the NER.[50] The AER has included in its procedure for assigning customers to tariff classes that the Qld DNSPs inform customers of the availability of the dispute resolution mechanism under Part 10 of the NEL.

Currently, jurisdictions differ as to the powers and functions of their individual energy Ombudsman schemes and its application to the network aspects of the electricity supply industry. Given the varying roles of jurisdictional energy Ombudsman the AER considers that at this time it is not appropriate to specify jurisdictional energy Ombudsman schemes in relation to the system of external review. However, if a jurisdictional energy Ombudsman scheme has been established to review such disputes the AER's procedure for assigning customers to tariff classes requires that the Qld DNSPs notify customers of this review mechanism. In such circumstances customers may prefer to refer disputes to the Ombudsmen under the jurisdictional schemes rather than to the AER under Part 10 of the NEL.

The procedure for assigning customers to tariff classes applicable to the Qld DNSPs is set out in appendix B of this draft decision.

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48 Ergon Energy, *Network use of system tariff guide—2009–10*, section 3b. Available at: <www.ergon.com.au/resources>.

49 AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 24–25.

50 Under Part 10 of the NEL, the AER has the function of resolving an access dispute between a network service user or prospective network user and a network service provider. An access dispute is a dispute about an aspect of access to an electricity network service that is specified under the NER to be an aspect about which the dispute resolution provisions in Part 10 of the NEL apply. Clause 6.22.1 in the NER relevantly provides that an access dispute for the purposes of Part 10 of the NEL includes a dispute between a DNSP and a Service Applicant about the terms and conditions of access to a direct control service.

2.7 AER conclusion

2.7.1 Classification of services

The AER does not consider that there are good reasons for departing from the classification of services set out in its framework and approach. The AER's service classifications are set out in appendix A to this draft decision.

2.7.2 Assigning customers to tariff classes

The AER's procedure for assigning and reassigning customers to tariff classes for the Qld DNSPs, based on the principles in clause 6.18.4 of the NER, are set out in appendix B of this draft decision.

2.8 AER draft decision

In accordance with clause 6.12.1(1) of the NER, the classification of services as set out in appendix A of this draft decision will apply to Energex for the next regulatory control period.

In accordance with clause 6.12.1(1) of the NER, the classification of services as set out in appendix A of this draft decision will apply to Ergon Energy for the next regulatory control period.

In accordance with clause 6.12.1(17) of the NER, the procedures to be applied by the Qld DNSPs for assigning customers to tariff classes or reassigning customers from one tariff class to another are specified in appendix B of this draft decision.

3 Arrangements for negotiation

3.1 Introduction

A distribution determination imposes controls over the prices and revenues that DNSPs can recover from the provision of direct control services. However, services classified as negotiated distribution services do not have their terms and conditions determined by the AER, being instead subject to a process of negotiation and dispute resolution.

Facilitating the negotiating process are two instruments:

1. negotiated distribution service criteria (NDSC)—set out the criteria that DNSPs are to apply in negotiating the terms and conditions of access for its negotiated distribution services. The AER also applies the NDSC in resolving disputes regarding these terms and conditions.
2. negotiating framework—sets out the procedures to be followed during negotiations between a DNSP and any person wishing to receive a negotiated distribution service.

The Qld DNSPs do not have services classified as negotiated distribution services and are not required to submit a negotiating framework, and hence none will apply in the next regulatory control period.

This chapter reviews issues raised in submissions regarding the NDSC, and sets out the AER's considerations and conclusions on the NDSC to apply to the Qld DNSPs in the next regulatory control period.

3.2 Regulatory requirements

Under clause 6.7.4(a) of the NER, the AER is to set out the criteria that are to be applied by a DNSP 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 the regulatory control period.

The NDSC will also be used by the AER in resolving any access dispute about the terms and conditions of access, including:[51]

> (i) the price that is to be charged for the provision of the negotiated distribution service by the provider; or
>
> (ii) any access charges that are to be paid to or by the provider.

[51] NER, clause 6.7.4(a)(2).

On 17 July 2009, the AER published its proposed NDSC to apply to the Qld DNSPs.[52] As required under clause 6.7.4(b) of the NER, the AER's proposed NDSC gives effect to and is consistent with the negotiated distribution service principles set out in clause 6.7.1 of the NER.

A decision on the NDSC to apply to the Qld DNSPs' negotiated distribution services is a constituent decision of the AER's distribution determination, under clause 6.12.1(16) of the NER. This requirement exists regardless of whether or not a DNSP has negotiated distribution services.

3.3 Submissions

The AER received a submission from AGL Energy Limited (AGL) regarding the NDSC applying to the Qld DNSPs. AGL's submission stated its general support for the AER's approach to the NDSC and each of the criteria, but proposed amendments to 5 of these criteria.[53]

Criterion 3

> The terms and conditions of access for a negotiated distribution service (including in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between a distribution network service provider (DNSP) and any other party, the price for the negotiated distribution service and the costs to a DNSP of providing the negotiated distribution service.[54]

AGL proposed that the words 'allocation of risk' be replaced with 'equitable allocation of risk' or 'reasonable allocation of risk'. AGL submitted that a DNSP is likely to be the only participant able to provide the negotiated distribution services and the risk allocation should recognise this imbalance in market power.[55]

Criterion 5

> The price for a negotiated distribution service must reflect the costs that a DNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the DNSP's Cost Allocation Method.[56]

AGL proposed that prices be subject to market testing and benchmarking, providing a transparent approach to determining the efficiency of prices.[57]

Criterion 6

> Subject to criteria 7 and 8, the price for a negotiated distribution service must be at least equal to the cost that would be avoided by not providing that service but no more than the cost of providing it on a stand alone basis.[58]

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[52] AER, *Call for submissions, Proposed negotiated distribution service criteria for Energex and Ergon Energy*, July 2009.
[53] AGL, *Proposed negotiated distribution service criteria for Energex and Ergon Energy*, August 2009, pp. 1–4.
[54] AER, *Proposed NDSC for Energex and Ergon Energy*, July 2009, p. 1.
[55] AGL, *NDSC for Energex and Ergon Energy*, August 2009, p. 2.
[56] AER, *Proposed NDSC for Energex and Ergon Energy*, July 2009, p. 1.
[57] AGL, *NDSC for Energex and Ergon Energy*, August 2009, p. 3.

AGL proposed that prices for negotiated distribution services be at least equal to the incremental costs of providing the services.[59]

Criterion 7

> If a negotiated distribution service is a shared distribution service that:
>
> (i) exceeds any network performance requirements which it is required to meet under any relevant electricity legislation: or
>
> (ii) exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER,
>
> then the difference between the price for that service and the price for the shared distribution service which meets network performance requirements must reflect a DNSP's incremental cost of providing that service (as appropriate).[60]

AGL proposed that the word 'difference' be replaced with 'net difference', stating this would account for the potential benefits to network performance that may derive from the additional services.[61]

Criterion 11

> The price for a negotiated distribution service must be such as to enable a DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated service.[62]

AGL proposed that the words 'efficient costs' be replaced with 'incremental costs', stating this is a fairer approach to the criterion.[63]

3.4 Issues and AER considerations

The AER notes that the Qld DNSPs did not propose any amendments to the NDSC. AGL's proposed amendments have been assessed for their consistency with the NDSC.

Criterion 3

The AER notes that AGL's proposed inclusion of the words 'equitable' or 'reasonable' to the allocation of risk could create uncertainty about the allocation of risk between a DNSP and other parties. This uncertainty could arise due to the difficulty in defining an equitable, or reasonable allocation of risk.

The AER considers that criterion 3 should not be amended.

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58 AER, *Proposed NDSC for Energex and Ergon Energy*, July 2009, p. 1.
59 AGL, *NDSC for Energex and Ergon Energy*, August 2009, p. 3.
60 AER, *Proposed NDSC for Energex and Ergon Energy*, July 2009, p. 1.
61 AGL, *NDSC for Energex and Ergon Energy*, August 2009, p. 3.
62 AER, *Proposed NDSC for Energex and Ergon Energy*, July 2009, p. 2.
63 AGL, *NDSC for Energex and Ergon Energy*, August 2009, p. 4.

Criterion 5

The AER notes AGL's proposal that prices be subject to market testing and benchmarking, to provide for a transparent approach to determining efficient prices. While the AER agrees that the determination of efficient prices for negotiated distribution services should be transparent, it notes that the regulatory approach to these services provides for transparency.

For example, under clauses 6.7.5(c)(1),(2), and clauses 6.7.5(c)(3)(i),(ii),(iii) of the NER, a negotiating framework must include provisions requiring that in negotiating a price with a service applicant a DNSP provides adequate and transparent information to that applicant, as to the cost and the cost reflectivity of the price that it has been quoted. These requirements arise from the principle under clause 6.7.1(1) of the NER, that the price for a negotiated distribution service reflects the cost of providing that service.

Given the often customised nature of negotiated distribution services, the potential value of benchmarking and market testing is likely to be limited. The AER notes that any assessment of a DNSP's prices is to be undertaken by a service applicant. The AER is only able to intervene in the negotiation process should a dispute arise regarding that price.

The AER considers that criterion 5 should not be amended.

Criterion 6

The AER notes AGL's recommendation that the price for the negotiated distribution service be at least equal to the incremental costs of providing the service. The AER considers it is possible that the avoided cost to the DNSP of not providing a negotiated distribution service is somewhere between an incremental cost and a stand alone cost. Therefore, altering the provision of criterion 6 could be detrimental to the DNSP. Criterion 6 notes that its provisions are subject to criteria 7 and 8 which refer to shared distribution services and recognise incremental costs in such instances.

The AER considers that AGL's concerns are already effectively captured in the wording of the NDSC and no amendment is required to criterion 6.

Criterion 7

The AER notes AGL's proposed replacement of the word 'difference' with 'net difference' stating this would take into account the potential benefits to network performance that may derive from the additional services.

However, the AER also notes that the difference referred to in criterion 7 is in fact a net amount. For example, criterion 7 refers to the gap between the price for a service X (which exceeds standards referred to therein) and the price for a service Y (which meets standards referred to therein). Therefore the gap, or the 'difference' is in fact a net amount of X minus Y. Furthermore, as criterion 7 refers to incremental costs, it will by definition have regard to any benefits that might be derived by the DNSP by providing services that are additional.

The AER considers that AGL's concerns are effectively captured in the wording of the NDSC and no amendment is required to criterion 7.

Criterion 11

The AER notes AGL's proposed replacement of the words 'efficient costs' with 'incremental costs'. The AER interprets AGL's proposal as indicating that DNSPs would derive some efficiencies through economies of scale and/or scope in complying with various regulatory obligations, and that such efficiencies are better captured by referring to incremental costs.

The AER notes that the intention of criterion 11 is that the only costs that should be incorporated into a DNSP's price are those relating to the regulatory obligations associated with the particular negotiated distribution service. The AER also notes it is possible that such efficiencies might be derived by a DNSP. However, this is not necessarily the case for all negotiated distribution services. The exact nature of the regulatory obligation might vary depending on the nature of the particular service. Therefore in some cases, the efficient cost to the DNSP would be a stand-alone cost and not an incremental cost.

The AER considers maintaining the words efficient cost in criterion 11 provides sufficient flexibility to ensure the cost of dealing with a regulatory obligation that is incorporated into a price for a negotiated distribution service, is targeted to the circumstances of the DNSP.

The AER considers that criterion 11 should not be amended.

3.5 AER conclusion

For the reasons set out in section 3.4 of this draft decision, the AER considers that the NDSC as proposed by the AER are consistent and give effect to the negotiated distribution services principles in clause 6.7.1 of the NER.

The NDSC applying to the Qld DNSPs for the next regulatory control period are in appendix C of this draft decision.

3.6 AER draft decision

In accordance with clause 6.12.1(16) of the NER, the NDSC to apply to Energex for the next regulatory control period are in appendix C of this draft decision.

In accordance with clause 6.12.1(16) of the NER, the NDSC to apply to Ergon Energy for the next regulatory control period are in appendix C of this draft decision.

4 Control mechanisms for standard control services

4.1 Introduction

A distribution determination imposes controls over the prices, and revenues, that DNSPs may recover from providing direct control services. Direct control services are categorised as either standard control services or alternative control services.[64] Classification of direct control services provided by the Qld DNSPs is discussed in chapter 2 of this draft decision.

The AER has published a framework and approach paper under clause 6.8.1 of the NER setting out the control mechanisms it proposes to apply to direct control services provided by the Qld DNSPs during the next regulatory control period. For the Qld DNSPs' standard control services this mechanism is a revenue cap. This chapter discusses how this mechanism will be applied and sets out how the AER will determine compliance with the mechanism during the next regulatory control period.

The control mechanism and assessment of the Qld DNSPs' proposals regarding alternative control services is in chapters 17–18 of this draft decision.

4.2 Regulatory requirements

Clause 6.12.1 the NER requires the AER to make the following constituent decisions which are related to the form of control mechanism for standard control services:

- a decision on the control mechanism (including the X factor) for standard control services (clause 6.12.1(11))
- a decision on how compliance with the relevant control mechanism is to be demonstrated (clause 6.12.1(13))
- a decision on how the DNSP is to report to the AER on its recovery of transmission use of system (TUOS) charges for each regulatory year and adjustments to be made in pricing proposals in subsequent years to account for TUOS over or under recoveries (clause 6.12.1(19)).

The AER published a framework and approach paper that sets out the following control mechanisms for the Qld DNSPs' standard control services for the next regulatory control period:[65]

- a revenue cap for standard control services
- a pass through of TUOS charges.

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[64] NER, clause 6.2.2.

[65] AER, *Final Decision, Framework and approach paper: Classification of services and control mechanism*, August 2008.

Transitional arrangements

Some of the transitional arrangements under the NER are relevant to the operation of the control mechanism. In summary, these provisions allow the Qld DNSPs to:

- maintain the approach allowed by the QCA in its 2005 determination in relation to the treatment of standard control services and other services in the regulatory asset base for the next regulatory control period[66]
- implement any price paths approved by the QCA, including any necessary adjustment of those price paths in light of the expected revenue for the first regulatory year of the regulatory control period.[67]

4.3 Queensland DNSP regulatory proposals

4.3.1 Energex

4.3.1.1 Form of control

Energex proposed a revenue cap control mechanism, of a CPI–X form for its standard control services.[68] The building blocks that make up Energex's revenue cap are discussed in chapter 16.

4.3.1.2 Application of the revenue cap

Energex proposed annual adjustments to its annual revenue allowance for:

- any under/over recoveries related to distribution use of system (DUOS) charges
- its performance against the service target performance incentive scheme (STPIS)
- adjustments for actual tax paid in 2008–09 and 2009–10
- any pass throughs approved by the AER during the next regulatory control period.

In addition, Energex has proposed a capital contribution bank to overcome the need for annual revenue adjustments for under/over recoveries related to capital contributions.

DUOS under/over recoveries

Energex proposed the same approach to the treatment of under/over recoveries of DUOS charges for the next regulatory control period as that used by the QCA during the current regulatory control period. Under this approach, the balance of the DUOS unders and overs account is assessed at the end of each regulatory year (based on two year lagged data and indexed by the nominal weighted average cost of capital (WACC)) and an adjustment made to the DNSP's revenues in the next regulatory year to offset the balance.

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[66] NER, clause 11.16.3.
[67] NER, clause 11.16.8.
[68] Energex, *Regulatory proposal*, July 2009, p. 98.

Energex proposed that the size of the adjustment to revenues for DUOS under/over recoveries would depend on tolerance limits that are consistent with the QCA approach in its 2005 determination, specifically:[69]

- less than 2 per cent – Energex proposed that the under/over recovery will be cleared within one regulatory year
- between 2 per cent and 5 per cent – Energex proposed the under/over recovery can be spread over two regulatory years
- greater than 5 per cent – Energex proposed to submit a plan to the AER detailing how it proposes to clear the balance.

Service target performance incentive scheme

Energex proposed that an adjustment be made annually to it allowed revenues for its performance against the STPIS.[70] These adjustments are discussed in chapter 12.

Tax under/over adjustments

Energex proposed under/over adjustments be made for actual tax paid in 2008–09 and 2009–10.[71]

Pass through

Energex proposed that an adjustment be made annually to it allowed revenues for cost pass throughs approved by the AER. This is discussed in chapter 15 of this draft decision.

Capital contribution under/over recoveries

Consistent with the QCA approach in the current regulatory control period, Energex included capital contributions in its RAB and an off setting revenue adjustment as a building block in the calculation of the X factor in the post–tax revenue model (PTRM).[72] The revenue adjustment is based on forecast capital contributions over the next regulatory control period. The QCA also allowed the Qld DNSPs to make an annual under/over adjustment where actual capital contributions subsequently differed from forecast. The data required for this adjustment is lagged by two years (for example, the adjustment for 2010–11 would be based on the correction of forecast for actual capital contributions for 2008–09). The difference between forecast and actual information is also indexed by the nominal WACC to maintain net present value (NPV) neutrality.

However, Energex raised a concern over the timing of these annual adjustments.[73] It noted that actual capital contributions have consistently exceeded forecast in the

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69 Energex, *Regulatory proposal*, July 2009, p. 104.
70 Energex, *Regulatory proposal*, July 2009, p. 258.
71 Energex, *Regulatory proposal*, July 2009, p. 105.
72 For a discussion on the required revenue adjustment for capital contributions, see chapter 16.
73 Energex, *Regulatory proposal*, July 2009, p. 271.

current regulatory control period and it expects this trend to continue throughout the next regulatory control period. Energex argued that:[74]

> To the extent that actual capital contribution is above forecast, no extra revenue is earned within the regulatory period. This is because the revenue has been pre-determined on a RAB based on the forecast capital expenditure. The extra capital expenditure will however be rolled into the RAB for the subsequent regulatory period and ENERGEX will start to earn a ROA [return on assets] and return of asset from that time.

For the next regulatory control period, Energex proposed that a "capital contributions bank" be established that would total the indexed value of cash and in kind payments over the entire period.[75] A settlement on the balance of this bank would then take place in the first year of the 2015–20 regulatory control period with a one off revenue adjustment. Energex's position is supported by a report it commissioned from Synergies Economic Consulting (Synergies).[76]

As a transitional measure, Energex proposed that any under/over adjustments related to capital contributions for 2008–09 and 2009–10 continue to be made on an annual basis, consistent with the QCA's current approach.[77]

4.3.1.3 Side constraints

Energex did not provide any comment in its regulatory proposal on how side constraints should be applied to its standard control services.

Energex noted under transitional clause 11.16.8 of the NER, it does not have any specific price paths (individual side constraints) approved by the QCA that carryover into the next regulatory control period.[78]

4.3.1.4 Transmission use of system charges

The TUOS charges that Energex is seeking to recover are:[79]

- payments of TUOS to Powerlink
- avoided TUOS payments to embedded generators
- payments to other DNSPs for use of their networks.

Energex proposed the same approach to the recovery of TUOS for the next regulatory control period as that used by the QCA during the current regulatory control period.[80] Under this approach any under/over recoveries of TUOS from year t–2 are carried forward to year t. Energex proposed that this carryover be determined by the difference between TUOS paid by DNSP in year t–2 minus the TUOS recovered from

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74 Energex, *Regulatory proposal*, July 2009, p. 271.
75 It is unclear from Energex's regulatory proposal whether it considers that in kind payments should be unindexed as Synergies Economic Consulting suggested in its report.
76 Energex, *Regulatory proposal*, July 2009, appendix 18.1 confidential.
77 Energex, *Regulatory proposal*, July 2009, p. 272.
78 Energex, *Regulatory proposal*, July 2009, p. 103.
79 Energex, *Regulatory proposal*, July 2009, p. 275.
80 Energex, *Regulatory proposal*, July 2009, p. 105.

customers in year t–2, plus an indexation adjustment based on the approved nominal WACC for the next regulatory control period.[81]

4.3.2 Ergon Energy

4.3.2.1 Form of control

Ergon Energy proposed a revenue cap control mechanism, of a CPI–X form for its standard control services.[82] The building blocks that make up Ergon Energy's revenue cap are discussed in chapter 16.

4.3.2.2 Application of the revenue cap

Ergon Energy proposed annual adjustments to its annual revenue allowance for:[83]

- any under/over recoveries related to DUOS charges
- any under/over recoveries related to capital contributions
- its performance against the STPIS
- use of standard control services assets by other businesses within Ergon Energy Corporation Limited
- any pass-throughs approved by the AER during the next regulatory control period.
- solar bonus scheme/feed-in tariff payments
- unfunded shared network events.

DUOS under/over recoveries

Ergon Energy proposed the same treatment of DUOS under/over recoveries for the next regulatory control period as the approach used by the QCA during the current regulatory control period.[84]

Capital contribution under/over recoveries

Ergon Energy proposed to continue with the QCA approach of annual adjustments for any unders/overs related to capital contributions.[85]

Service target performance incentive scheme

Ergon Energy has proposed that an adjustment be made annually to its allowed revenues for its performance against the STPIS.[86] This adjustment is discussed in chapter 12 of this draft decision.

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[81] Energex, *Regulatory proposal*, July 2009, p. 276.
[82] Ergon Energy, *Regulatory proposal*, July 2009, p. 15.
[83] Ergon Energy, *Regulatory proposal*, July 2009, p. 437.
[84] Ergon Energy, *Regulatory proposal*, July 2009, pp. 376 and 431.
[85] Ergon Energy, *Regulatory proposal*, July 2009, p. 423.
[86] Ergon Energy, *Regulatory proposal*, July 2009, pp. 436–437.

Use of shared assets

Ergon Energy proposed that all shared assets be included in the regulatory asset base for standard control services. To account for the use of these shared assets for purposes other than standard control services, Ergon Energy has included an offsetting revenue adjustment in its PTRM. In addition, Ergon Energy proposed that an annual under/over adjustment be made to its allowed revenues to account for any difference between the expected and actual use of the shared assets for purposes other than standard control services.[87]

Cost pass through

Ergon Energy proposed that an adjustment be made annually to it allowed revenues for cost pass throughs approved by the AER, including feed in tariff/solar bonus scheme, and unfunded shared network events. These adjustments are discussed in chapter 15 of this draft decision.

4.3.2.3 Side constraints

Ergon Energy only addressed the issue of side constraints in relation to the transitional provisions of the NER. It noted that clause 11.16.8 of the NER allows it to continue to implement any price paths approved by the QCA. Ergon Energy proposed retaining a list of individual price paths approved by the QCA that carryover into the next regulatory control period.[88]

4.3.2.4 Transmission use of service

Ergon Energy did not identify the specific types of TUOS costs it would seek to recover over the next regulatory control period. However, it proposed the same broad approach to the recovery of TUOS (including under/over recoveries) for the next regulatory control period as that used by the QCA during the current regulatory control period.[89]

4.4 Submissions

No submissions were received on the form of control.

4.5 Issues and AER considerations

4.5.1 Form of control

Both Energex and Ergon Energy proposed revenue caps for their standard control services. The AER accepts the Qld DNSPs’ proposed form of control as it is consistent with the AER’s position in its framework and approach paper. The revenue cap will take the form of a CPI–X approach, with the X factors based on the various building block costs. These building block costs and the calculation of the X factors are discussed in chapter 16.

[87] Ergon Energy, *Regulatory proposal*, July 2009, p. 438.
[88] Ergon Energy, *Regulatory proposal*, July 2009, p. 451, table 143, confidential.
[89] Ergon Energy, *Regulatory proposal*, July 2009, p. 446.

4.5.2 Application of the revenue caps

4.5.2.1 DUOS unders and overs account

The Qld DNSPs proposed a continuation of the QCA approach to under/over recovery of DUOS charges each year. The AER considers that the QCA approach will allow the DNSP to recover its revenue cap over time in a manner that is NPV neutral. The AER considers the proposed approaches are consistent with the transitional provisions of the NER.

The AER also accepts Energex's proposal to include the tolerance limits used by the QCA in the settlement of this account as being consistent with the transitional provisions of the NER. Similarly, Ergon Energy should continue to apply these tolerance limits as part of the continuation of the QCA approach that it has proposed.

The AER has developed a DUOS unders and overs account based on the approach used by the QCA to recover DUOS unders and overs. The operation of this account is detailed in appendix D.

To account for DUOS under/over recoveries the term '$unders\&overs_t$' has been included in the side constraint formula set out in the AER conclusion section.

4.5.2.2 Changes in inflation

Neither of the Qld DNSPs addressed the issue of how changes in inflation should be dealt with over the next regulatory control period. Under the current regulatory regime no annual adjustments are made to the Qld DNSPs' allowed revenues for changes in inflation. Instead, the Qld DNSPs simply received an allowance for inflation from the QCA based on a fixed forecast rate of inflation for the entire regulatory control period with no further adjustment, during the regulatory control period.

The AER's general approach to the application of revenue caps in other regulatory contexts (for example, electricity transmission) is to adjust the maximum allowable revenue (MAR) annually for changes in the actual rate of inflation. Accordingly, for the next regulatory control period, the AER considers that the Qld DNSP's MAR should be adjusted for actual inflation in a similar fashion. This approach is reflected in the MAR formula set out in the AER's conclusion below.[90]

4.5.2.3 Capital contribution unders/overs

The AER accepts the Qld DNSPs' proposals to include forecast capital contributions in their RABs as provided for under clause 11.16.3 of the NER. This approach necessitates an offsetting revenue adjustment for these forecast contribution contributions when calculating the X factors in the PTRM. Details on the forecast capital contributions and the size of the required revenue adjustments are detailed in chapter 16.

The AER accepts Ergon Energy's proposal to account for capital contributions under/over recoveries on an annual basis, using the same approach adopted by the

90 AER, *Final decision, TransGrid transmission determination 2009–10 to 2013–14*, p. 184.

QCA for the current regulatory control period (discussed above). However, the AER does not accept Energex's proposal of a capital contribution bank. The AER's key considerations in reaching this decision were:

- Energex's concern regarding annual over/under adjustments for capital contributions is based on its expectation that actual capital contributions will consistently exceed forecast. The AER notes that, if actual contributions are less than forecast, by Energex's own logic, it would benefit from annual adjustments (that is, under recoveries would be returned to Energex but the asset base would still be based on the higher forecast capital contribution amounts).

- The AER considers that Energex's assumed trend of over recoveries is questionable.[91] While the trend expected by Energex has been observed in the past, the AER expects that Energex's experience in this regard should have assisted it in preparing more accurate forecasts of capital contributions for the next regulatory control period.

- If Energex is correct regarding the future trend of capital contributions, banking the over recoveries until the end of the next regulatory control period could lead to a significant cumulative over recovery at the start of the 2015–20 regulatory control period. The AER considers that such an adjustment would lead to more significant price adjustments than the current approach of reconciling unders/overs on an annual basis. Accordingly, a P_0 adjustment as proposed by Energex would not be desirable in such circumstances. The possibility of a large cumulative unders/overs adjustment was acknowledged by Synergies in its report.[92] The AER considers Synergies' suggested solution to such a possibility, namely to spread the adjustment over the 2015–20 regulatory control period, is not desirable. The Synergies proposal would mean that, depending on the year in which the under/over recovery emerged, it could take up to ten years for certain under/over recoveries to be reconciled in full.

- At the core of Energex's concern with annual under/over adjustments related to capital contributions appears to be the approach used to account for capital contributions and the timing of cash inflows and outflows related to these contributions.[93] The AER notes that Energex does not need to include capital contributions in its RAB, and if it did not, it would avoid the need for any revenue adjustments. However, Energex has chosen to include capital contributions in its RAB and this decision necessitates offsetting revenue adjustments and unders/overs adjustments.

The AER requires Energex to account for capital contributions under/over recoveries on an annual basis. This is consistent with the transitional provisions of the NER,

91 Synergies example on page 21 of its confidential report includes both under and over recoveries. If this example showed only over recoveries, the cumulative under/over recovery at the end of the period would be significantly larger than shown.
92 Energex, *Regulatory proposal*, July 2009, appendix 18.1, p. 21, confidential.
93 Energex, *Regulatory proposal*, July 2009, appendix 18.1, p. 14, confidential.

which allow the Qld DNSPs to maintain the same approach to the treatment of the RAB adopted by the QCA in the current regulatory control period.[94]

To account for capital contribution under/over recoveries a term ‘C_t’ has been included in the MAR and side constraint formulas set out in the AER conclusion section.

4.5.2.4 Service target performance incentive scheme

The AER accepts the Qld DNSPs’ proposal to include an annual adjustment to their MAR for their performance against the STPIS. The size and timing of these adjustments are discussed in chapter 12.

To account for the Qld DNSPs’ performance against the STPIS a term ‘S_t’ has been included in the MAR and side constraint formulas set out in the AER’s conclusion below.

4.5.2.5 Transitional adjustments

A term ‘transitional_t’ has been included in the MAR and side constraint formulas to account for transitional matters related to tax and the use of shared assets by other business units with the DNSP. These transitional issues are discussed in turn below.

Adjustments related to tax

The AER will continue, on a transitional basis, the adjustments to Energex’s MAR for actual tax paid in 2008–09 and 2009–10, consistent with the QCA’s approach for the current regulatory control period.

Ergon Energy stated it is not expecting to pay any tax during the current regulatory control period. This has been the situation over the first three years of the current regulatory control period and assuming this situation continues, no transitional tax adjustment will be required for the final two years of the current regulatory control period.[95]

Use of shared assets by other business units within the DNSP

Given the transitional provisions of clause 11.16.3 of the NER, the AER accepts Ergon Energy’s proposal to continue with the approach to shared assets approved by the QCA.[96] This approach allows Ergon Energy to retain that proportion of shared assets used for non standard control services (that is, unregulated and alternative control services) in its regulatory asset base and to make an offsetting forecast revenue adjustment to account for this inclusion. In addition, any under/over recoveries relative to the forecast revenue adjustment will be accounted for two years after the year to which they relate.[97]

Energex has also included shared assets used for the provision of alternative control services in its regulatory asset base. Consistent with the approach approved by the

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94 NER, clause 11.16.3.
95 Ergon Energy, *Regulatory proposal*, July 2009, p. 370.
96 QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 172.
97 Ergon Energy, *Regulatory proposal*, July 2009, section 51.2.2.1, p. 438.

QCA for Energex, it has included an off–setting forecast revenue adjustment as a building block in the calculation of the X factor for standard control services. The forecast revenue adjustment is presented in chapter 16. Unlike for Ergon Energy, the QCA approach for Energex does not require any annual under/over adjustment for any difference between forecast and actual use of shared assets and Energex has not proposed such an adjustment.

4.5.2.6 Pass throughs

The AER accepts that the Qld DNSPs' allowed revenues will be adjusted for approved cost pass throughs. Chapter 15 provides further detail on the costs that the Qld DNSPs may seek to pass through during the next regulatory control period.

To account for cost pass throughs, a term '$passthrough_t$' has been included in the MAR and side constraint formulas set out in the AER conclusion section.

4.5.3 Side constraints

4.5.3.1 Individual side constraints

Ergon Energy proposed that some of its customers pricing outcomes should continue to be side constrained in accordance with individual price paths approved by the QCA.[98] These price paths were intended to move these customers to cost reflective prices by the end of the current regulatory control period.[99] The AER understands that it has taken longer than initially intended by Ergon Energy to move these customers' prices to cost reflectivity. The AER accepts Ergon Energy's proposal as it is consistent with clause 11.16.8 of the NER.

4.5.3.2 Application of the side constraints

Notwithstanding Ergon Energy's proposal regarding individual side constraints for certain customers, neither of the Qld DNSPs presented details on how side constraints should be applied across the tariff classes they proposed. The AER considers there are benefits in clarifying how the side constraints will be applied in practice and has developed a side constraint formula consistent with clause 6.18.6 of the NER. This formula is presented in section 4.6.

While it is preferable to base quantities under a weighted average price cap on actual quantities from year t–2, the AER considers that under a revenue cap it is preferable for DNSPs to demonstrate compliance with their revenue caps[100], and side constraints, using forecast quantities for year t. This is because, unlike a price cap, the DNSP must try to forecast demand changes so as to set prices which lead to expected revenues that equal the revenue cap.[101] The AER also understands that this was the approach allowed by the QCA during the current regulatory control period.

98 Ergon Energy, *Regulatory proposal*, July 2009, p. 451, table 143, confidential.
99 QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 194.
100 Subject to DUOS and TUOS unders and overs accounts described in appendices D and E.
101 The revenue cap for any given year is the MAR for that year plus any under/over adjustment needed to get the balance of their DUOS unders and overs account to zero for that year.

4.5.4 Transmission use of system charges

The Qld DNSPs will be allowed to recover costs related to payments of TUOS to Powerlink, avoided TUOS payments to embedded generators and payments to other DNSPs for use of their network.

The Qld DNSPs proposed a continuation of the QCA approach to under/over recovery of TUOS payments each year. The AER has accepted these proposals as being consistent with clause 6.18.7 of the NER. The operation of the TUOS unders and overs account is detailed in appendix E.

4.6 AER conclusion

As part of their pricing proposals, the Qld DNSPs must submit to the AER proposed tariffs and charging parameters which lead to expected revenues consistent with the MAR formula set out below plus any unders/overs adjustment needed to move the balance of their DUOS unders and overs account to zero (or agreed tolerance level).

4.6.1 Maximum allowable revenue formula

The MAR for the first year of the next regulatory control period will be set equal to the allowed revenue (AR) for the first year of the next regulatory control period:

$$MAR_1 = AR_1$$

where:

MAR_1 is the maximum allowed revenue for year 1 (that is, 2010–11) of the next regulatory control period.

AR_1 is the allowed revenue for year 1 of the next regulatory control period.

The MAR for the subsequent years of the regulatory control period requires annual adjustments based on the previous year's AR. That is, the subsequent year's AR is determined by adjusting the previous year's AR for actual inflation and the X factor:

$$AR_t = AR_{t-1} \times \left(1 + \Delta CPI_t\right) \times \left(1 - X_t\right)$$

where:

AR is the allowed revenue

t is the regulatory year (excluding year 1)

ΔCPI_t is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in year *t*–2 to March in year *t*–1

X_t is the X factor for each year of the regulatory control period.

The MAR is determined annually by adding to, or subtracting from, the AR any STPIS revenue increment (or revenue decrement) and any approved pass through amounts, as follows:

$$MAR_t = AR_t \pm S_t \pm C_t \pm transitional_t \pm passthrough_t$$

where:

MAR_t is the maximum allowed revenue for year *t* (excluding year 1) of the next regulatory control period

AR_t is the allowed revenue for regulatory year *t*

S_t is the STPIS factor to be applied in regulatory year *t*

C_t is the annual adjustment factor for the difference between actual and forecast capital contributions in year *t*–2 and indexed for two years by the nominal rate of return

$transitional_t$ is a transitional factor for matters such as under/over in tax paid during the current regulatory period and under/over adjustments related to standard shared assets used for purposes other than standard control services

$passthrough_t$ is the approved pass through amounts with respect to regulatory year t, as determined by the AER.

4.6.2 Side constraints

In their annual pricing proposals, the Qld DNSPs will be required to demonstrate that their proposed DUOS prices for the next year (t) will meet the following side constraints formula for each tariff class:

$$\frac{\sum_{j=1}^{m} d_t^j \times q_t^j}{\sum_{j=1}^{m} d_{t-1}^j \times q_t^j} \leq (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + 2\%) \pm S_t \pm C_t \pm transitional_t \pm passthrough_t \pm unders\ \&\ overs_t$$

where each tariff class ‘j’ has up to ‘m’ components, and where:

d_t^j is the proposed price for component *j* of the tariff class for year t

d_{t-1}^j is the price charged by the DNSP for component *j* of the tariff class in year *t*–1

q_t^j is the forecast quantity of component *j* of the tariff class in year *t*

ΔCPI_t is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year *t*–2 to March in regulatory year *t*–1

X_t is the X factor for each year of the regulatory control period. If $X > 0$, then X will be set equal to zero for the purposes of the side constraint formula

S_t is the STPIS factor to be applied in regulatory year t

C_t is the annual adjustment factor for the difference between actual and forecast capital contributions in year t–2

$transitional_t$ is a transitional factor for matters such as under/over in tax paid during the current regulatory period and under/over adjustments related to shared assets used for purposes other than standard control services

$passthrough_t$ is an annual adjustment factor that reflects the pass through amounts approved by the AER with respect to regulatory year t

$unders\&overs_t$ is an annual adjustment factor related to the balance of the DUOS under and over account with respect to regulatory year t.

In addition, Ergon Energy must continue to apply individual side constraints to those customers listed in table 143 (confidential) of its regulatory proposal.

4.6.3 Ring fencing and compliance monitoring

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 QCA ring fencing guidelines are therefore applicable transitional guidelines for Queensland.[102] 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:

- legal separation of entities
- definition of related businesses
- accounting and auditing requirements, cost allocation
- information flows to related businesses
- ring fencing waivers
- procedures for revising the guidelines.

Cost allocation methods prepared by the Qld DNSPs that are to be applied in the next regulatory control period were approved by the AER in February 2009.

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[102] QCA, *Final determination, Electricity distribution: Ring-fencing guidelines*, September 2000.

The QCA stated that a DNSP is required to demonstrate compliance and its compliance report must identify the policy, state how it has been implemented and identify how the effectiveness of the policy will be monitored and/or audited.[103]

The transitional guidelines contain regulatory reporting requirements. Amongst other things, these reporting requirements provide the AER with the information that is required to ensure that distribution charges for standard (and alternative) control services are set, and have been set, in accordance with the final determination. These reporting arrangements will continue in the next regulatory control period. As such, the regulatory reporting guidelines approved by the QCA will also continue to apply.[104] The application of the reporting guidelines is an obligation of the transitional guidelines (clause 2).[105]

To the extent that the QCA's reporting guidelines do not cover additional matters addressed in this draft decision, such as the incentive schemes discussed in chapters 12, 13 and 14, appendix Q of this draft decision sets out reporting requirements. This appendix should be read in conjunction with the QCA's regulatory reporting guidelines.

4.7 AER draft decision

In accordance with clause 6.12.1(11) of the NER, the control mechanism for standard control services provided by Energex is a revenue cap.

The revenue cap for any given regulatory year is the MAR for that regulatory year (as calculated using the formula in section 4.6.1 of this draft decision) plus any under/over adjustment required to move the DUOS under/over account (as set out in appendix D to this draft decision) to zero (or the agreed tolerance level).

The side constraints to apply to the price movements of each of Energex's tariff classes must be consistent with the formula in section 4.6.2 of this draft decision.

In accordance with clause 6.12.1(19) of the NER, Energex must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix E of this draft decision.

In accordance with clause 6.12.1(13) of the NER, Energex must demonstrate compliance with the control mechanism for standard control services in accordance with appendices D and E of this draft decision.

[103] QCA, *Final determination, Regulation of electricity distribution*, April 2005, p. 212.
[104] QCA, *Electricity distribution: Regulatory reporting guidelines*, Version 4.1, November 2005.
[105] QCA, *Final determination, Electricity distribution: Ring-fencing guidelines*, September 2000, p. 21.

In accordance with clause 6.12.1(11) of the NER, the control mechanism for standard control services provided by Ergon Energy is a revenue cap.

The revenue cap for any given regulatory year is the MAR for that regulatory year (as calculated using the formula in section 4.6.1 of this draft decision) plus any unders/overs adjustment required to get the DUOS under/overs account (as set out in appendix D to this draft decision) to zero (or the agreed tolerance level).

The side constraints to apply to the price movements of each of Ergon Energy's tariff classes must be consistent with the formula in section 4.6.2 of this draft decision.

In accordance with clause 6.12.1(19) of the NER, Ergon Energy must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix E of this draft decision.

In accordance with clause 6.12.1(13) of the NER, Ergon Energy must demonstrate compliance with the control mechanism for standard control services in accordance with appendices D and E of this draft decision.

5 Opening regulatory asset base

5.1 Introduction

This chapter sets out the method used by the AER to determine the closing regulatory asset base (RAB) for the Qld DNSPs for the current regulatory control period. The closing RAB for the current regulatory control period becomes the opening RAB for the next regulatory control period and is used to calculate the annual building block revenue requirements.

5.2 Regulatory requirements

Clause 6.5.1 of the NER outlines the approach to be used to determine the opening RAB for a distribution determination. Consistent with the requirements of this clause, the AER published an asset base roll forward model (RFM) which sets out the method for determining the roll forward of the RAB.[106]

Clause S6.2.1(c)(1) of the NER provides that the RAB for the first year of the next regulatory control period must be determined by rolling forward the RAB values (as at 1 July 2005) set out in the schedule as follows:

- Energex – $4308.1 million
- Ergon Energy – $4198.2 million, but if the QCA nominates a different amount in writing to the AER, the RAB is the amount so nominated.

Transitional arrangements

The Qld DNSPs also have transitional arrangements under the NER for determining their RABs. Specifically, clause 11.16.3 of the NER states:

> (a) Nothing in Chapter 6 of the Rules requires ENERGEX or Ergon Energy to amend the approach allowed in the 2005 determination in relation to the treatment of standard control services and other services in the regulatory asset base for the regulatory control period.
>
> (b) The AER must accept the approach proposed by ENERGEX and Ergon Energy for the regulatory control period if it is consistent with the approach in the 2005 determination.
>
> (c) The AER must provide for any necessary adjustments or mechanisms in the distribution determination for the regulatory control period to prevent any cross-subsidies between standard control services and other distribution services.
>
> Note:
>
> The regulatory asset bases for Ergon Energy and ENERGEX are likely to include assets used to provide services which are not standard control services and accordingly the expected revenue for each year will need to be adjusted to avoid double recovery of those costs.

[106] AER, *Final decision, Electricity distribution network service providers, Roll forward model*, June 2008.

5.3 Queensland DNSP regulatory proposals

5.3.1 Energex

Energex proposed an opening RAB for the next regulatory control period of $7984 million as at 1 July 2010.[107] The proposed opening RAB has been derived by taking an opening RAB of $4345 million as at 1 July 2005 and making the following adjustments:[108]

- addition of $4113 million for capex incurred during the current regulatory control period (net of disposals and inclusive of contributed assets)[109]
- reduction of $554 million for depreciation based on actual capex
- addition of $53 million reflecting the amount of actual expenditure above forecast expenditure for 2004–05
- addition of $27 million reflecting an adjustment for the return on the $53 million of capex above forecast for 2004–05
- indexation for actual inflation using the CPI.

Energex's proposed calculation of the RAB roll forward from 1 July 2005 to 1 July 2010 is detailed in table 5.1.

Energex stated that its proposed opening RAB as at 1 July 2005 differs from the RAB contained in the NER due to the fact that its actual capex for 2004–05 was $526 million[110] whereas the forecast allowance set by the QCA in its final determination was $448.4 million.[111]

Energex stated that the QCA has already fully compensated it for $37 million by including this value in Energex's RAB for the current regulatory control period and also making adjustments to Energex's allowed revenues to reflect foregone returns.

For this reason, Energex considered that it is appropriate that the starting RAB should reflect this value and for the remaining difference between forecast and actual (including disposals) be addressed by applying the approach set out in the RFM. Energex made an adjustment of $53.1 million to reflect the difference after application of the RFM.

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107 Energex, *Regulatory proposal*, July 2009, p. 231.
108 Energex, *Regulatory proposal*, July 2009, pp. 230–231.
109 Energex, *Regulatory proposal*, July 2009, derived from table 14.2, p. 231.
110 Since its proposal, Energex has clarified that the value of $541.7 million contained in its proposal was a typographical error and that the actual capex was $526 million. See Energex, email to AER, issue no: AER.EGX.19, 17 September 2009, confidential.
111 Energex, *Regulatory proposal*, July 2009, p. 229.

Table 5.1: Energex proposed RAB roll forward for the current regulatory control period ($m, nominal)

	Actual			Estimated	
	2005–06	**2006–07**	**2007–08**	**2008–09**	**2009–10**
Opening RAB 1 July	4345.2	4996.7	5596.7	6248.6	7003.4
Net capex	744.7	734.7	694.4	890.5	1048.0
Regulatory depreciation	–93.2	–134.7	–42.5	–135.7	–148.2
Difference between forecast and actual 2004–05	–	–	–	–	53.1
Adjustment for return on variance	–	–	–	–	27.3
Closing balance 30 June	4996.7	5596.7	6248.6	7003.4	7983.6
Contributed assets	38.8	47.2	49.3	44.1	70.6
Inflation rate	2.98%	2.44%	4.24%	2.47%	2.45%

Source: Energex, *Regulatory proposal*, July 2009, p. 231.

5.3.2 Ergon Energy

Ergon Energy has proposed an opening RAB for the next regulatory control period of $6999 million as at 1 July 2010.[112] The proposed opening RAB has been derived by taking the most recent RAB advised by the QCA of $4146 as at 1 July 2005 and making the following adjustments:

- addition of $3512 million for capex incurred during the current regulatory control period (net of disposals and inclusive of contributed assets)[113]
- reduction of $659 million for depreciation based on actual capex
- indexation for actual inflation using the CPI.

Ergon Energy stated its opening RAB as at 1 July 2005 differs from that contained in the NER due to the fact that since the publication of the NER, the QCA has nominated a different RAB value of $4232 million. Applying the QCA advised value as the new opening RAB, Ergon Energy also proposed a number of additional adjustments:[114]

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112 Ergon Energy, *Regulatory proposal*, July 2009, p. 381.
113 Ergon Energy, *Regulatory proposal*, July 2009, derived from table 109, p. 381.
114 Ergon Energy, *Regulatory proposal*, July 2009, p. 381.

- removal of $39 million of working capital which was included by the QCA which is no longer appropriate on the basis that the post–tax revenue model (PTRM) has a working capital provision inherent in its calculations

- removal of $47 million reflecting that street lighting assets are now an alternative control service and are treated separately from standard control services

- removal of $0.2 million for market metering assets incorrectly included in the RAB determined by the QCA.

Factoring in these adjustments provides for an opening RAB as at 1 July 2005 of $4146 million as detailed in table 5.2.

Table 5.2: Ergon Energy's proposed RAB roll forward for the current regulatory control period, ($m, nominal)

	Actual			Estimated	
	2005–06	**2006–07**	**2007–08**	**2008–09**	**2009–10**
Opening RAB 1 July	4146.2	4648.6	5285.0	5792.4	6294.1
Actual/estimated net capex	621.2	724.1	648.5	684.3	833.9
Actual/estimated regulatory depreciation	–118.7	–87.7	–141.1	–182.6	–128.6
Closing balance 30 June	4648.6	5285.0	5792.4	6294.1	6999.4
Actual/estimated contributed assets	36.2	42.0	70.5	51.9	66.4
Actual/estimated inflation rate	2.67%	3.54%	2.33%	1.75%	2.75%

Source: Ergon Energy, *Regulatory Proposal*, July 2009, p. 381.

5.4 Submissions

No submissions were received on this issue.

5.5 Issues and AER considerations

5.5.1 Opening asset value 1 July 2005

A key aspect of any building block approach to regulation is the value assigned to the opening RAB in the previous regulatory control period. The RAB has a substantial impact on distribution charges through the return of capital (depreciation) and return on capital components of the allowed revenue.

Clause S6.2.1(c) of the NER prescribes the opening value of the RAB for both Energex and Ergon Energy for the beginning of the regulatory control period for this distribution determination.

In addition, clause S6.2.1(c)(2) requires that the RAB at the beginning of the first regulatory year is to be adjusted for the difference between any estimated capex for any part of the 2001–05 regulatory control period and the actual capex for the same period. This adjustment must also incorporate any benefit or penalty associated with any difference between the estimated and actual capex.

Energex

The value of the RAB as at 1 July 2005 for Energex as set out on in clause S6.2.1 of the NER is $4308 million.

This value is predicated on a forecast capex set by the QCA in 2004–05 of $448.4 million.[115]

Energex has nominated a RAB value as at 1 July 2005 of $4345 million on the basis that this value includes an adjustment for actual capex, depreciation and inflation allowed by the QCA during 2004–05 in accordance with clause S6.2.1(c)(2) of the NER.[116] Energex has provided correspondence from the QCA which states:[117]

> In the 2005 Final Determination, the Authority committed to adjust Energex's opening asset base, where appropriate, once actual capex data became available. Forecast capex for 2004–05 was to be replaced with actual capex data (depreciation and inflation associated with the forecast capex was to be adjusted as well)…The QCA had recalculated Energex's revised opening asset base value at 1 July 2005 to be $4345.2 million, $37.1 million higher than the 2005 Final Determination forecast of $4308.1 million.

In its regulatory proposal, Energex stated that it is appropriate to include the amount of $37 million into the RAB set out in the NER as Energex has already been compensated for foregone earnings by the QCA for this expenditure. However, Energex also suggested the QCA adjustment reflected only some of the variance between forecast and actual capex in 2004–05.[118]

Energex indicated that its actual capex for 2004–05 was $526 million, a difference of $78 million compared to the QCA forecast. After taking into account disposals of $6 million and $37 million already included in the RAB by the QCA, Energex sought to include a further $35 million into the RFM.

While the AER considers that the NER does not allow for any departure from the use of opening RAB values prescribed in S6.2.1 (with the exception of Ergon Energy) the AER is mindful of recognising the treatment of actual capex by the previous regulator to ensure no double counting of expenditure in the RAB.[119]

While Energex has not nominated an opening RAB value contained in the NER, the AER is nevertheless satisfied that Energex has used the NER value as the base with which to recognise what it has already been compensated for by the QCA. The

[115] QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 68.
[116] Energex, *Regulatory proposal*, July 2009, p. 229.
[117] Energex, letter from QCA to Energex, 23 March 2006, RE: Attachment A to Regulatory Proposal, August 2009, confidential.
[118] Energex, *Regulatory proposal,* July 2009, p. 229.
[119] NER, clause S6.2.1.

alternative to this approach would have involved Energex proposing the NER RAB and removing the QCA allowed value of $37 million from its RAB along with any returns on and of allowed by the QCA and then including this value back into the RFM.

The AER considers that this would create an unnecessary level of administrative burden on Energex when it is unlikely to result in an outcome significantly different to that already proposed. For this reason, the AER is satisfied with Energex's proposal to apply the NER RAB as the base and to include the value that the QCA has already compensated Energex for.

In terms of the remaining $35 million between actual and forecast capex, the AER has assessed Energex's regulatory reporting statements submitted to the QCA and is satisfied with the accuracy and appropriateness of this value.

The AER has also reviewed the manner with which Energex has included this value in the AER's RFM and is satisfied that Energex has applied the RFM correctly.

For this reason, the AER has accepted an opening RAB as at 1 July 2005 of $4345 million and the inclusion of $37 million into the RFM. The impact on the annual RAB roll forward is presented in table 5.5.

Ergon Energy

The value of the RAB as at 1 July 2005 for Ergon Energy as set out on in clause S6.2.1 of the NER is $4198 million. The clause provides that this value is to be applied by the AER unless the QCA nominate a different amount in writing to the AER.

Ergon Energy has provided correspondence from the QCA that advised Ergon Energy of its RAB as at 1 July 2005.[120] In this correspondence, the QCA stated:

> The Authority has recalculated Ergon Energy's revised opening asset base at 1 July 2005 to be $4,232.4 million, $34.2 million higher than the 2005 Final Determination forecast of $4,198.2 million. Table 1 shows the impact of the revised opening asset base value on Ergon Energy's AARRs over the regulatory period (using the same approach as adopted in the 2005 Final Determination).

Ergon Energy has proposed an opening RAB of $4146 million. This value has been developed by taking the latest RAB of $4232 million proposed by the QCA[121] and applying a number of adjustments as detailed in table 5.3.

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[120] Ergon Energy, letter from QCA to Ergon Energy, 23 March 2006, issue no: AER.ERG.04, August 2009.

[121] Ergon Energy, letter from QCA to Ergon Energy, 23 March 2006, issue no: AER.ERG.04, August 2009.

Table 5.3: Ergon Energy's proposed 1 July 2005 opening RAB ($m, nominal)

	Adjustments
1 July 2005 RAB from QCA	4232.4
Removal of working capital	–39.0
Removal of street lighting assets	–47.0
Removal of market metering assets	–0.2
Balance as at 1 July 2005	4146.2

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 382.

While the AER has not received this advice directly from the QCA, as S6.2.1 of the NER requires, it will accept this value for the purposes of this draft decision and confirm the value directly with the QCA prior to the release of its final decision.

In terms of the adjustments made by Ergon Energy, the removal of street lighting assets from the standard control services RAB is consistent with Ergon Energy’s proposal to have these assets regulated separately to standard control services. The AER has accepted this approach and this matter is discussed in chapter 17 of this draft decision.

The AER also considers that the adjustment for working capital is appropriate as inventory is captured within the AER’s post–tax revenue model. The AER also accepts that the inclusion of market metering assets in Ergon Energy’s original RAB was an error.

5.5.2 Escalation rate for RAB roll forward

The NER provides that the roll forward of the RAB be adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism during the preceding regulatory control period.[122]

Energex has applied the Australian Bureau of Statistics (ABS) weighted average of eight capital cities, March to March annual CPI.[123] Ergon Energy has applied CPI, although it was not clear to the AER which date range had been adopted by Ergon Energy.

In its 2005 Decision, the QCA used a number of different approaches to estimate inflation. For the purposes of forecast inflation, the QCA applied the difference between the 10 year Commonwealth bond rate and a similar duration indexed bond rate, averaged over 20 trading days.[124] With respect to rolling forward the Sinclair

[122] NER, clause 6.5.1(e)(3).
[123] Energex, *Regulatory proposal*, July 2009, p. 230.
[124] QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 125.

Knight Merz Pty Ltd (SKM) asset base valuation, the QCA applied the ABS CPI All Groups, Weighted Average of Eight Capital Cities Index to June 2004.[125]

As the CPI All Groups rate was used by the QCA to roll forward the SKM asset base valuation, the AER has also adopted this CPI measure as being consistent with the NER. However, while the AER accepts the method, the temporal range still needs to be determined.

Energex has proposed a spread of March to March on the basis that this will be the most recent data available at the time of the AER's final decision.

In terms of the temporal range, the AER considers that the March to March provides the most up to date data at the time of its final decision. Actual data for March to March CPI is contained in table 5.4. These CPI rates will apply to both the Qld DNSPs' RAB for the purposes of actual inflation.

As the March to March data for 2009–10 is unavailable at the time of this draft decision, the AER will apply the Qld DNSPs' forecast inflation rates for 2009–10. It should be noted that this rate will be updated at the time of the AER's final decision.

Table 5.4: ABS CPI All Groups, Weighted Average of Eight Capital Cities Index (per cent)

	2005–06	2006–07	2007–08	2008–09	2009–10
12 Months to March CPI	2.98	2.44	4.24	2.47	TBA

Source: ABS, *Consumer Price Index,* Australia, Cat no: 6401.0.

5.5.3 Roll forward methodology

In accordance with the RFM and those transitional chapter 6 rules applicable to Energex and Ergon Energy, the closing RAB (nominal) for each year of the current regulatory control period is calculated by:

1. increasing the opening RAB by the amount of capex incurred (including estimated capex for the remaining part of the current regulatory control period) and adjusted for the difference between actual CPI and forecast inflation
2. reducing the opening RAB by the amount of regulatory depreciation using the rates and methodologies allowed in the 2005 QCA determination, adjusted for the difference between actual CPI and forecast inflation
3. reducing the opening RAB by the amount of disposal value of any disposed assets.

At the end of the current regulatory control period, the closing RAB is adjusted for the difference between estimated capex during the previous regulatory control period and actual capex for that part of the period, and the return on the difference.

[125] QCA, excel spreadsheet: '2005 Final Determination Model Energex.xls', worksheet: 'Inputs'.

Energex

Applying the RFM, Energex derived an opening RAB as at 1 July 2010 of $7984 million as detailed in table 5.1.[126]

The AER has reviewed Energex's proposed opening RAB adjustments and the cost inputs to the RFM for the previous regulatory control period and has cross checked these against Energex's regulatory accounts. The AER is satisfied that Energex has completed the RFM in accordance with the requirements of the NER.

Energex has allocated this RAB into standard control services and alternative control services. Energex has proposed a split as follows:[127]

- $7887 million for standard control services RAB
- $96 million for alternative control services asset base (street lighting assets).[128]

As noted in section 5.5.2, the AER will update the CPI inputs to the RFM for the current regulatory control period at the time of its final decision. For the purposes of this draft decision, the AER accepts the proposed opening RAB for Energex of $7887 million as at 1 July 2010.

This value is used as an input for the PTRM for the purposes of determining Energex's maximum allowable revenues during the next regulatory control period.

In terms of the allocation between standard control and alternative control, the AER is satisfied that there is no double counting of assets and no cross-subsidisation between the two types of services.

Ergon Energy

Ergon Energy has proposed to remove street lighting assets from its proposed RAB and consistent with the AER's framework and approach paper sought for these assets to be treated separately. As indicated in table 5.2, Ergon Energy has removed a value of $47.0 million from its opening RAB as at 1 July 2005. The AER has cross referenced this value against the QCA's revenue model for Ergon Energy and is satisfied that this value is accurate.[129]

Applying the RFM Ergon Energy derived an opening RAB as at 1 July 2010 of $6999 million as detailed in table 5.2.

The AER has reviewed Ergon Energy's proposed opening RAB adjustments and the cost inputs to the RFM for the current regulatory control period and has cross checked these against Ergon Energy's regulatory accounts. The AER is satisfied that Ergon Energy has completed the RFM in accordance with the requirements of the NER.

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126 Energex, *Regulatory proposal*, July 2009, p. 231.
127 Energex, *Regulatory proposal*, July 2009, pp. 231–232.
128 This value is derived from Energex's RFM and PTRM (confidential). In Energex's regulatory proposal, it presents a value of $96.4 million for alternative control services asset base (street lighting assets).
129 QCA, excel spreadsheet: '2005 Final Determination Model Ergon.xls', worksheet: 'DORC', cell: O252.

As noted in section 5.5.2 Ergon Energy did not apply the QCA's method to determine the CPI inputs to the RFM for the current regulatory control period. The AER has amended these inputs to reflect the QCA indexation method and adopted the figures shown in table 5.4 for the years 2005–06 to 2008–09. Based on these updated CPI inputs, the AER has determined Ergon Energy's opening RAB to be $7105 million for the next regulatory control period (as at 1 July 2010). This value is used as an input for the PTRM for the purposes of determining Ergon Energy's maximum allowable revenues during the next regulatory control period.

5.5.4 RAB roll forward for the following regulatory control period.

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 July 2015), is to be based on actual or forecast capex (referred to here as the use of actual or forecast depreciation).

The use of actual or forecast depreciation relates to whether the return of capital forms part of the capex incentive framework. For example, in the case of a capex overspend, under the actual depreciation framework, the opening RAB would be reduced by a higher amount of depreciation (reflecting the higher capex) than if forecast depreciation was applied. In this case, the DNSP loses the return on the capital in excess of the capex allowance and incurs faster depreciation of its RAB. The situation is reversed for capex underspends where the reward is potentially higher.

5.5.4.1 Qld DNSPs regulatory proposals

Ergon Energy proposed that actual capex be used for the period 2005–06 to 2007–08 and forecast capex for the period 2008–09 to 2009–10, but provided no explanation for this proposal.[130]

5.5.4.2 AER considerations

The AER considers that Ergon Energy has misunderstood the purpose of clause 6.12.1(18) of the NER. This clause requires the AER to decide how the opening RAB for the 2015-20 regulatory control period will be determined, not how it will be determined for the next regulatory control period as Ergon Energy has interpreted the clause.

The AER notes that the NER does not offer any criteria regarding its decision on the use of actual or forecast depreciation or on the capex incentive framework generally. Section 7A(3) of the NEL provides general guidance with respect to incentives:

> 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

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130 Ergon Energy, *Regulatory proposal*, July 2009, p. 368.

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

An important consideration in the choice between the use of actual or forecast depreciation, is whether any difference between the actual and forecast outcomes are likely to be driven by changes in efficiency or whether these differences are likely to reflect uncontrollable factors. If the differences are likely to result from uncontrollable factors, then the use of actual depreciation will result in windfall gains/losses to the Qld DNSPs.

The AER assesses the scope and cost of the capex programs and the Qld DNSPs investment needs in chapter 7 of this draft decision. The AER also considers whether the Qld DNSPs' capex programs are supported by appropriate resourcing and delivery strategies. Given these assessments, the AER considers that any uncontrollable differences between actual costs and those accounted for in this determination should be minimised, and the resulting risk of windfall gains and losses should be no more than those experienced by any competitive (that is, efficient) business.

In this context, the AER considers it important to provide effective incentives for the Qld DNSPs to seek out efficiencies wherever possible in their capex programs, and that a high powered incentive is therefore appropriate. The AER considers the use of actual depreciation to establish the opening RAB for the 2015–20 regulatory control period provides the most effective incentives to the Qld DNSPs.

5.6 AER conclusion

Energex

The RAB roll forward calculations for Energex are set out in table 5.5 and provides for an opening RAB of $7887 million for standard control services and an opening RAB of $96 million for alternative control services for the next regulatory control period (as at 1 July 2010). The combined standard and alternative control services opening RAB as at 1 July 2010 is $7984 million.

Table 5.5: Opening RAB to apply to Energex ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB	4345.2	4996.7	5596.7	6248.6	7003.4
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	744.6	734.7	694.4	890.5	1048.0
Straight–line depreciation (adjusted for actual CPI)	–93.2	–134.7	–42.5	–135.7	–148.2
Closing RAB	4996.7	5596.7	6248.6	7003.4	7903.2
Difference between actual and forecast capex for 2004–05					53.1
Return on difference					27.3
Adjustment for street lighting services					–96.1
Opening RAB at 1 July 2010					7887.4

(a) Based on estimated net capex.
(b) Based on estimated net capex and forecast inflation rate.

The AER will update the roll forward of Energex's RAB with actual capex for 2008–09 and the most recent forecast of capex for 2009–10, and the latest actual CPI data at a time closer to its final distribution determination.

Ergon Energy

The RAB roll forward calculations for Ergon Energy are set out in table 5.6, and provides for an opening RAB of $7105 million for the next regulatory control period (as at 1 July 2010). The AER will update the roll forward of Ergon Energy's RAB with actual capex for 2008–09 and the most recent forecast of capex for 2009–10, and the latest actual CPI data at a time closer to its final distribution determination.

Table 5.6: Opening RAB to apply to Ergon Energy ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB[c]	4146.2	4662.4	5243.4	5858.1	6402.4
Actual net capex (adjusted for actual CPI and WACC)	622.1	720.2	654.5	686.8	833.9
Straight–line depreciation (adjusted for actual CPI)	–105.9	–139.3	–39.8	–142.4	–131.0
Closing RAB	4662.4	5243.4	5858.1	6402.4	7105.4
Opening RAB at 1 July 2010					7105.4

(a) Based on estimated net capex.
(b) Based on estimated net capex and forecast inflation rate.
(c) Excludes an amount of $47 million related to street lighting assets. The roll forward of this amount is discussed in chapter 17.

The AER will update the roll forward of Ergon Energy's RAB with actual capex for 2008–09 and the most recent forecast of capex for 2009–10, and the latest actual CPI data at a time closer to its final distribution determination.

5.7 AER draft decision

In accordance with clause 6.12.1(6) of the NER the total opening asset base for Energex as at 1 July 2010 is $7983.6 million, consisting of $7887.4 million for standard control services and $96.1 million for alternative control services.

In accordance with clause 6.12.1(6) of the NER the opening asset base for Ergon Energy as at 1 July 2010 is $7105.4 million.

In accordance with clause 6.12.1(18) of the NER, the AER has decided to use actual depreciation for establishing the regulatory asset base for the commencement of the 2015–20 regulatory control period.

6 Demand forecasts

6.1 Introduction

This chapter discusses the AER's consideration of whether the Qld DNSPs' maximum demand, customer number and energy forecasts reflect a reasonable expectation of the demand for standard control services over the next regulatory control period. The AER also considers the extent to which the forecasts can be relied upon for the purposes of assessing the proposed load driven capex.

6.2 Regulatory requirements

The NER requires DNSPs to provide a realistic expectation of the maximum demand forecast as part of addressing the capex and opex objectives and criteria under clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3). The NER also requires the AER, as part of its distribution determination, to make a decision on appropriate amounts, values or inputs, under clause 6.12.1(10).

The AER's assessment of the Qld DNSPs' demand forecasts is focussed on the expected summer maximum (or peak) demand and customer numbers over the next regulatory control period. Maximum demand (measured in MW or MVA) is the highest level of network capacity sought at a single point in time and is a key driver of load driven capex requirements. Forecasts of customer numbers are an input to the forecasts of maximum demand and can be a driver of particular opex requirements. The AER also reviewed energy forecasts (measured in GWh), which measure the amount of electricity that is expected to be transported over a period of time, but which do not have a significant impact on the calculation of the DNSPs' revenue requirements.

6.3 Queensland DNSP regulatory proposals

6.3.1 Energex regulatory proposal

Energex forecast maximum demand on its network over the next regulatory control period using both a bottom up method based on internally produced forecasts of maximum demand at the zone substation level of the network (also known as 'spatial' demand forecasts) and a top down method (also known as system or global demand forecast) based on key drivers.[131] Energex validated these forecasts using independently produced system maximum demand forecasts by National Institute of Economic and Industry Research (NIEIR).[132]

Energex also engaged ACIL Tasman to review its 10 year demand forecasting approach and indicated that it incorporated some of ACIL Tasman's recommendations when preparing its forecasts for the next regulatory control period.[133]

[131] Energex, *Regulatory proposal*, July 2009, p. 144.
[132] Energex, *Regulatory proposal*, July 2009, p. 138.
[133] Energex, *Regulatory proposal*, July 2009, p. 144.

Energex stated that its ‘baseline’ maximum demand and energy consumption forecasts were developed in July 2008 and therefore did not include the potential impacts of recent events such as the global financial crisis (GFC), demand management initiatives and the introduction of a Carbon Pollution Reduction Scheme (CPRS). However, Energex stated that it had completed preliminary modelling based on the most recent NIEIR forecast (April 2009) to estimate the impacts of the GFC and the proposed introduction of a CPRS. Energex also accounted for the impacts of its demand management initiatives in adjusting its baseline maximum demand forecasts, as shown in table 6.1.[134]

Energex’s forecasts of summer maximum demand at the 50 per cent probability of exceedence (PoE) level,[135] customer numbers and energy consumption are presented in table 6.1.

Table 6.1: Energex maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 (%)
Baseline system maximum demand (50% PoE) – MW	5486	5767	6023	6250	6490	4.4
NIEIR April 2009 system maximum demand (50% PoE) – MW	5144	5378	5700	5945	6085	4.0
System maximum demand reductions arising from demand management initiatives (50% PoE) – MW	–18	–40	–67	–101	–144	
Adjusted system maximum demand (50% PoE) – MW	5126	5338	5633	5844	5941	2.6
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294	2.1
Energy consumption – GWh	22 416	23 138	24 042	24 795	25 845	3.0

Source: Energex, *Regulatory proposal*, July 2009, RSD 2.3.8 and p. 154.
Note: Average annual growth rate calculated based on 2009–10 to 2014–15 data.

6.3.1.1 Key drivers

Energex identified the following key drivers of maximum demand and energy consumption on its network:[136]

134 Energex, *Regulatory proposal*, July 2009, pp. 149–154.
135 Summer peak demand specified at 50 per cent PoE means that the probability of this maximum demand being exceeded is 50 per cent, or on average one in two years.
136 Energex, *Regulatory proposal*, July 2009, p. 138.

- customer number growth and distribution patterns
- economic growth in south east Queensland
- climate considerations
- the impact of air conditioner use
- the projected impact of demand management strategies.

Energex's network has been summer peaking over the previous and current regulatory control periods and is forecast to be summer peaking in the next regulatory control period.

6.3.1.2 Review of past forecasts

Forecast and actual demand outcomes for Energex during the current regulatory control period are presented in table 6.2.

Table 6.2: Energex maximum demand, customer number and energy consumption – forecasts and actuals

	2005–06	2006–07	2007–08	Average annual growth (%)
System maximum demand (50% PoE) – 2005 QCA approved forecast – MW	4162	4433	4699	6.2
System maximum demand – actual weather corrected – MW	4363	4716	4673	3.6
Variation (%)	4.8	6.4	–0.6	
Customer numbers – 2005 QCA approved forecast	1219 000	1246 000	1277 000	2.4
Customer number – Actual	1216 889	1245 016	1275 786	2.4
Variation (%)	–0.17	–0.08	–0.10	
Energy consumption – 2005 QCA approved forecast – GWh	20 373	21 114	21 945	3.8
Energy consumption – actuals – GWh	20 757	20 758	20 879	0.3
Variation (%)	1.9	–1.7	–4.9	

Source: Energex, *Regulatory proposal*, July 2009, Attachment RSD 2.3.8; and QCA, *Final Determination Regulation of Electricity Distribution*, April 2005, pp. 33–34.

Energex's weather corrected actual maximum demand is higher than the forecast 50 per cent PoE level in 2005–06 and 2006–07, but lower than forecast in 2007–08. This result largely depends on the reasonableness of Energex's weather correction methodology, which is discussed in section 6.5.1.2.

Customer numbers have grown by an average annual rate of 2.4 per cent over the period 2005–06 to 2007–08, which is the same rate approved by the QCA in 2005.

Energex indicated that between 2005–06 and 2007–08, actual energy consumption on its network grew at an average annual rate of only 0.3 per cent, mainly due to relatively mild summers during 2006–07 and 2007–08. This was 3.5 per cent lower than the growth forecast of 3.8 per cent approved by the QCA in 2005.

6.3.1.3 Maximum demand forecast methodology

Energex prepared both spatial and system maximum demand forecasts on its network over the next regulatory control period. Energex validated it own forecasts against system maximum demand forecasts prepared by NIEIR.[137]

Energex forecast methodology

Energex provided an outline of its internally produced system maximum demand forecasting process, which included the following steps:[138]

- identify the external drivers of electricity demand
- quantify the relationship between the external drivers and the impact on electricity demand using statistical analysis
- produce the forecasts using the driver relationships and validate the inputs and outputs using external independent projections
- continually monitor the performance of the forecasts against recorded results.

Energex provided an outline of its internally produced spatial (zone substation) maximum demand forecasting process, which included the following steps:[139]

- calculate the uncompensated measures of historical winter and summer loads by adjustment for any capacitors and embedded generators that were operating at the time of substation peak. Use these as the starting points for the zone substation, bulk supply substation and connection point demand forecasts
- smooth and temperature correct historical load data using a process that reviews up to the past five years of starting values and trends the maximum demand starting values for the summer day and night demands and the winter day and night demands
- forecast substation growth rates each year by assessing the following five key growth factors:
    - detached housing (subdivision data, amount of vacant land for development)

[137] Energex, *Regulatory proposal*, July 2009, p. 138.
[138] Energex, *Regulatory proposal*, July 2009, appendix 10.1 Energex peak demand and energy consumption forecast 2009–2015, p. 7, confidential.
[139] Energex, *Regulatory proposal*, July 2009, appendix 10.1, pp. 50–51, confidential.

    - multi–unit developments
    - renewal developments
    - commercial and industrial developments
    - air conditioning retrofitting

- link census population data for 2006 to substation areas and use the expertise and local knowledge of the area asset managers to establish year on year growth rates

- determine the starting values by averaging the historical validated substation peak demands over the past five year period. Establish a 50 per cent PoE starting value by adjusting peak demands recorded at temperature sensitive substations based on the ACIL Tasman analysis

- produce a cycle of forecast runs and reviews to ensure alignment between the top down system demand forecast reconciled with the bottom up substation demand forecast allowing for diversity of loads and loss factors

- aggregate zone substation forecasts to determine bulk supply forecasts, reconcile these with the system level demand forecast using the trim factor,[140] and then validate the forecasts with an independent system forecast carried out for Energex by NIEIR.

NIEIR forecast methodology

Energex provided a high level outline of NIEIR's system maximum demand forecasting process, which included the following steps:[141]

- separate annual maximum demand into temperature sensitive demand and temperature insensitive demand

- forecast temperature insensitive maximum demand using NIEIR's industry based energy model for base, high and low economic growth scenarios

- forecast maximum winter temperature sensitive demand using an econometric regression which relates the ratio of maximum demand and energy to daily average temperature

- forecast maximum summer temperature sensitive demand by using an econometric regression which relates daily average temperature and space cooling appliance (air conditioner) consumption.

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[140] The trim factor is used by Energex to 'scale' its aggregated spatial level maximum demand forecasts (adjusted for co-incidence factors) to reconcile with the overall system wide 50 per cent PoE maximum demand forecasts. A large trim factor indicates that the relative growth rate of the aggregated maximum demand forecasts at spatial level is higher than system forecasts. See MMA, *Review of Energex's demand forecasts*, October 2009, p. 58.

[141] Energex, *Regulatory proposal*, July 2009, Appendix 10.2 NIEIR, Electrcity consumption and maximum demand projection for Energex region to 2018, pp. 27–30, confidential.

6.3.2 Ergon Energy regulatory proposal

Ergon Energy forecast maximum demand on its network for the next regulatory control period using a bottom up method based on internally produced forecasts of maximum demand at the bulk supply point and zone substation level of the network (also known as 'spatial' demand forecasts). Ergon Energy used spatial maximum demand forecasts to identify where it needs to augment individual components of its distribution system.[142] Ergon Energy used a top down forecast of its network maximum demand from NIEIR to review, check and, where necessary, amend its internally prepared demand forecasts.[143]

Ergon Energy's network has been summer peaking over the previous and current regulatory control periods and is forecast to be summer peaking in the next regulatory control period. Forecasts of summer maximum demand, energy consumption and customer numbers are provided in table 6.3

Table 6.3: Ergon Energy maximum demand, customer number and energy consumption forecasts 2010–15

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 (%)
System maximum demand (50% PoE) – MW	2967	3063	3153	3243	3330	3.1
Customer numbers	684 469	695 242	706 204	717 356	728 706	1.6
Energy consumption – GWh	15 871	16 450	16 874	17 433	17 887	3.9

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 159
Note: Average annual growth rate calculated based on 2009–10 to 2014–15 data.

Ergon Energy's bottom up forecast of system maximum demand was prepared internally by its network forecasting and development group. To validate its internal spatial forecasts, Ergon Energy engaged NIEIR to develop independent forecasts of Ergon Energy's maximum demand by connection points and regions, energy consumption and customer numbers over the next regulatory control period.[144]

6.3.2.1 Key drivers

Ergon Energy identified the following key drivers of maximum demand and energy consumption on its network:[145]

- population growth

[142] Ergon Energy, *Regulatory proposal*, July 2009, p. 168.
[143] Ergon Energy, *Regulatory proposal*, July 2009, p. 174.
[144] Ergon Energy, *Regulatory proposal*, July 2009, p. 160.
[145] Ergon Energy, *Regulatory proposal*, July 2009, p. 161.

- major new industry and commercial development
- economic growth
- climate effects and air conditioner penetration.

6.3.2.2 Review of past forecasts

Forecast and actual demand outcomes for Ergon Energy during the current regulatory control period are presented in table 6.4.

Table 6.4: Ergon Energy maximum demand, customer number and energy consumption – forecasts and actuals

	2005–06	2006–07	2007–08	Average annual growth (%)
System maximum demand (50% PoE) – 2005 QCA approved forecast – MW	2331	2464	2554	4.7
System maximum demand – actual – MW	2380	2584	2332	–0.6
Variation (%)	2.1	4.9	–8.7	
Customer numbers – 2005 QCA approved forecast	606 000	618 000	629 000	1.9
Customer numbers – actual	625 988	638 181	653 222	2.2
Variation (%)	3.3	3.3	3.9	
Energy consumption – 2005 QCA approved forecast – GWh	13 358	13 650	13 944	2.2
Energy consumption – actual – GWh	13 486	13 576	13 813	1.2
Variation (%)	1.0	–0.5	–0.9	

Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8 (confidential).

Summer maximum demand was higher than the 50 per cent PoE forecasts for 2005–06 and 2006–07, but lower than the 50 per cent PoE forecasts in 2007–08. These results are not unexpected, given that summer maximum demand specified at 50 per cent PoE means that the probability of this maximum demand being exceeded is 50 per cent, or that it will be exceeded, on average one in two years.

Customer numbers have grown by an average annual rate of 2.2 per cent over the period 2005–06 to 2007–08, which is higher than the QCA approved forecast of 1.9 per cent.[146]

Ergon Energy indicated that over the period 2005–06 to 2007–08, actual energy consumption on its network grew at an average annual rate of 1.2 per cent, which is lower than the QCA approved growth forecast of 2.2 per cent.

The AER also understands that actual total energy consumption over the period 2005–06 to 2007–08 was 0.2 per cent lower than the forecast level approved by the QCA in 2005–06.[147] Lower than forecast energy consumption reflects a reduction in energy consumption associated with a relatively mild summer season in 2007–08.[148]

6.3.2.3 Maximum demand forecast methodology

Ergon Energy's capex forecast is based on internally produced, bottom up, spatial demand forecasts produced in November 2007. Ergon Energy stated its spatial demand forecasts were validated against the NIEIR November 2007 forecasts of Ergon Energy's maximum demand by connection points and regions. Ergon Energy noted that the use of 2007 forecasts is due to the timing for the preparation of its regulatory proposal.[149] Ergon Energy also stated that in light of the GFC, it is conservative to base its capex program on the 2007 forecasts as they are lower than forecasts prepared in 2008 and 2009.[150]

NIEIR forecast methodology

Ergon Energy provided a high level outline of NIEIR's maximum demand forecasting process, which included the following steps:[151]

- forecast non–coincident peak demand by connection point by first estimating the temperature sensitivity of the load by connection point for each season using half hourly data for the last three years
- use the temperature sensitivity coefficients to develop econometric regression equations which relate the ratio of maximum demands to energy to average temperature at system maximum demand
- derive coincidence factors for the regions in Ergon Energy's network, and apply the coincidence factors to forecast non–coincident peak demand to derive the coincident peak demand forecast for each region in Ergon Energy's network.

Ergon Energy provided a high level outline of NIEIR's energy consumption forecasting process, which included the following steps:[152]

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[146] Ergon Energy indicated that the actual customer numbers are not directly comparable to forecast customer numbers provided from the QCA's 2005 Final Determination, as the figures were prepared on a different basis and for a different purpose.
[147] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8, confidential.
[148] QCA, *Financial and Service Quality Performance 2007–08 Ergon Energy*, March 2009.
[149] Ergon Energy, *Regulatory proposal*, July 2009, p. 160.
[150] Ergon Energy, *Regulatory proposal*, July 2009, p. 160.
[151] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR065c NIEIR, Maximum demand forecasts for Ergon Energy connection points to 2017, pp. 40–44, confidential.

- forecast commercial and industry electricity consumption based on econometric models which link electricity consumption by industry to real output growth by industry, electricity prices, and weather conditions

- forecast residential electricity consumption based on econometric models which link electricity consumption to average consumption per dwelling, weather, real income, and electricity prices

- divide Ergon Energy's network into six supply regions including Far North, North Queensland, Mackay, Capricornia, Wide Bay and South West

- develop an electricity consumption forecast for each of the six supply regions within Ergon Energy's network using regional specific driver indicators such as dwelling stock formation; output by commercial and industrial sectors; mining output projections; and household income growth.

Ergon Energy spatial forecast methodology

Ergon Energy provided an outline of its spatial maximum demand forecasting process, which included the following steps:[153]

- derive actual historical maximum demand by seasonal and annual periods from half hour metered data without weather normalisation, for each of the bulk supply points and zone substations across Ergon Energy's six supply regions

- use straight–line regression analysis for each of summer, winter and annual peak demand recorded to generate a ten year peak demand forecast

- identify likely future step changes in load and incorporate these into the forecast on a probabilistic basis depending on the size, timing and the likelihood of proceeding

- calculate the coincident factor by averaging ten years of history data, and apply the coincident factor to derive coincident peak demand for each bulk supply point and zone substation at 50 per cent and 10 per cent PoE levels

- aggregate coincident peak demand across all bulk supply points, zone substations and regions to form the system peak demand for Ergon Energy's network

- distribute peak demand forecasts within Ergon Energy for peer review and test and validate the forecasts against NIEIR's forecasts to reconcile significant differences.

6.4 Submissions

The AER received submissions from the Energy User Association of Australia (EUAA) and Origin in relation to the Qld DNSPs' demand forecasts for the next regulatory control period.

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152 Ergon Energy, *Regulatory proposal*, July 2009, attachment AR065c, pp. 37–39, confidential.
153 Ergon Energy, *Regulatory proposal*, July 2009, pp. 168–170.

The EUAA stated that the Qld DNSPs' demand and customer forecasts need to be closely examined by the AER to account for the impacts of the GFC. The EUAA also stated that the AER needs to review Energex's historical demand growth to test the veracity of its projections. The EUAA submitted that there is a lack of clarity around Ergon Energy's demand and customer number forecasts and noted that it is unclear what demand forecast had been used, and what the relationship is between demand forecast produced by Ergon Energy and those produced by NIEIR.[154]

Origin stated that the AER should closely examine Energex's peak demand and consumption forecasts, particularly the impacts of the GFC and the CPRS. Origin submitted that more than three years of historical data for Energex would assist the assessment of demand trends. Origin also stated that the AER should assess the impact of increases in regulated retail prices on Energex's peak demand and energy volumes.[155]

6.5 Consultant review

The AER engaged McLennan Magasanik Associates (MMA) to provide assistance in reviewing the demand forecasts used by the Qld DNSPs. As the Qld DNSPs are regulated under a revenue cap, maximum demand forecasts are key inputs into demand driven capex forecasts. The focus of MMA's review has therefore been the Qld DNSPs' maximum demand forecasts and methodologies. MMA also reviewed customer number forecast methodologies and forecasts, as customer number growth is a contributory factor to maximum demand growth, and can be a driver of particular opex requirements.

The review process involved MMA undertaking a preliminary assessment of the Qld DNSPs' forecasting methods prior to the submission of their regulatory proposals. MMA then reviewed the demand forecasts and methodologies described within the regulatory proposals, before seeking additional information.

6.5.1 Maximum demand

MMA reviewed the Qld DNSPs' system wide, or global, maximum demand forecasts as well as the forecasts at zone substations, or spatial demand forecasts. MMA focussed on summer maximum demand forecasts as the Qld DNSPs' networks are forecast to continue having summer peaking loads.

6.5.1.1 System maximum demand forecasts

Energex

MMA stated that Energex's system maximum demand forecasts were very important because Energex considers that it reflects key drivers of demand and uses it to adjust its spatial forecasts through the application of a trim factor.[156]

[154] EUAA, *Submission to the AER*, 28 August 2009, sections 4.4 and 4.5.
[155] Origin, *Queensland DNSPs*, August 2009, pp. 1–3.
[156] MMA, *Review of Energex's demand forecasts*, October 2009, p. 4.

MMA reviewed the key drivers of Energex's maximum demand, including growth in Queensland's economy, air conditioner penetration and customer numbers. MMA made the following observations:

- Queensland economic growth – MMA expected a significant reduction in Queensland's economic growth from 5 per cent a year over the period 2002 to 2008 and considered that NIEIR's forecast of 2.8 per cent annual growth over the period 2008–09 to 2014–09 lies within MMA's expected range of 2–3 per cent[157]

- air conditioner penetration – based on relevant data from the Australian Bureau of Statistics (ABS)[158] and the Queensland Office of Economic and Statistical Research (OESR),[159] MMA projected an increase in air conditioner penetration from 68 per cent in 2008 to 81 per cent in 2015, based on significantly slower growth in penetration than over the period 2004 to 2008[160]

- customer number growth – based on a review of the growth drivers underlying Energex's customer number forecasts, including growth in the population and dwelling numbers and changes in the occupancy rate, MMA considered that Energex's forecast of 2.15 per cent annual growth in customer numbers over the period 2008–2015 was reasonable[161]

- CPRS and energy efficiency programs – MMA expects maximum demand growth over the period 2008 to 2015 to be lower than over the period 2002 to 2008, due to the proposed introduction of the CPRS and other energy efficiency programs. However MMA considered the extent of these impacts was very difficult to quantify.[162]

MMA reviewed Energex's baseline system maximum demand forecast model to assess Energex's forecasting methodology. MMA found that the model to be biased, as it appeared to double count the maximum demand growth due to gross state product (GSP) growth and air conditioner penetration.[163] MMA also considered that the absolute number of air conditioners should be used[164] to replace the air conditioner penetration rate as an explanatory variable in the multi-linear regression analysis, to more accurately account for the underlying growth in air conditioners.[165]

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[157] MMA, *Review of Energex's demand forecasts*, October 2009, pp. 13–14.
[158] ABS, Cat. number: 4602.0.55.001, *Environmental issues energy use and conservation,* November 2008.
[159] Queensland OESR, *May 2008 Queensland Household Survey*, May 2008. The Office of Economic and Statistical Research, a portfolio office of Queensland Treasury, is the principal economic, demographic and social research agency for the Queensland Government.
[160] MMA, *Review of Energex's demand forecasts*, October 2009, pp. 19–24.
[161] MMA, *Review of Energex's demand forecasts*, October 2009, p. 7.
[162] MMA, *Review of Energex's demand forecasts*, October 2009, pp. 28–30.
[163] MMA, *Review of Energex's demand forecasts*, October 2009, pp. 42–43.
[164] The absolute number of air conditioners is calculated by multiplying the number of customers by the air conditioner penetration rate.
[165] It is possible for the numbers of air conditioners in use to grow while the penetration rate remains constant.

For these reasons, MMA concluded that Energex's forecast model was not suitable for forecasting 50 per cent PoE maximum demand.[166]

MMA reviewed Energex's proposed demand management initiatives and considered it was reasonable to apply the proposed demand management impacts on Energex's system maximum demand forecast through the trim factor.[167]

MMA produced an alternative set of maximum demand forecasts for the next regulatory control period based on a modified version of Energex's system maximum demand model, which corrected the identified methodological flaws. MMA compared its forecasts against NIEIR's April 2009 forecasts, which Energex used as the basis for the top down adjustment of its 50 per cent PoE system maximum demand forecasts.[168] MMA's forecasts and NIEIR's April 2009 forecasts, both excluding the impacts of Energex's proposed demand management initiatives, are presented in table 6.5.

Table 6.5: MMA and NIEIR 50 per cent PoE system maximum demand forecasts (MW)

	2009	2010	2011	2012	2013	2014	2015
MMA	4624	4762	4882	5067	5295	5567	5828
MMA – top of range	4750	4888	5008	5193	5421	5693	5954
NIEIR	4635	4997	5144	5378	5699	5945	6085

Source: MMA, *Review of Energex's demand forecasts*, October 2009, p. 48.
Note: NIEIR's 2009 values are actual whereas MMA's values are weather normalised.

MMA noted that NIEIR's forecasts are on average 6.1 per cent higher than MMA's forecasts. However, MMA acknowledged that milder than normal summer weather conditions in 2007–08 and 2008–09 have created greater uncertainty regarding the values of weather normalised 50 per cent PoE maximum demand in those years. Reflecting this uncertainty, MMA established a likely range for maximum demand in 2008–09 of 4600MW to 4750MW. This is based on MMA's own forecasts and forecasts contained in the Powerlink 2009 Annual Planning Report.[169] MMA considered that if its forecasts are adjusted to reflect the top of the reasonable range in 2008–09 as well as the impact of demand management impacts, then its forecasts would still be on average, 3.5 per cent less than the NIEIR forecasts (adjusted to reflect demand management impacts).[170]

Ergon Energy

MMA noted that Ergon Energy does not prepare a top down system wide forecast based on economic, demographic and other key drivers. MMA noted that Ergon Energy claimed to take account of top down maximum demand forecasts produced by

166 MMA, *Review of Energex's demand forecasts*, October 2009, p. 4.
167 MMA, *Review of Energex's demand forecasts*, October 2009, p. 50.
168 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 45–49.
169 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 43–44.
170 MMA, *Review of Energex's demand forecasts*, October 2009, p. 6.

NIEIR when preparing its internal bottom up forecasts. However, MMA found that Ergon Energy does not in any way systematically reconcile its bottom up forecasts to the NIEIR forecasts and does not document the differences between the two forecasts.[171]

MMA reviewed the key drivers of Ergon Energy's maximum demand, including growth in Queensland's economy, air conditioner penetration and customer numbers. MMA found the following:

- Queensland economic growth – MMA expected a significant reduction in Queensland's economic growth, from 5 per cent a year over the period 2002 to 2008 to the range of 2–3 per cent over the next regulatory control period[172]

- air conditioner penetration – based on relevant data from the ABS and the OESR, MMA projected an increase in air conditioner penetration from 71 per cent in 2008 to 82 per cent in 2015, based on significantly slower growth in penetration than over the period 2004 to 2008[173]

- customer number growth – based on a review of the growth drivers underlying Ergon Energy's customer number forecasts, including growth in the population and dwelling numbers and changes in the occupancy rate, MMA considered that Ergon Energy's forecast of 1.6 per cent annual growth in customer numbers over the period 2008–2015 is a little low but not unrealistic[174]

- CPRS and energy efficiency programs – MMA expects maximum demand growth over the period 2008 and 2015 to be lower than over the period 2002 to 2008, due to the proposed introduction of the CPRS and other energy efficiency programs. However MMA considered the extent of these impacts was difficult to quantify.[175]

6.5.1.2 Spatial maximum demand forecasts

Energex

MMA reviewed historical and forecast information for four zone substations to assess Energex's spatial demand forecasting methodology.[176]

MMA considered that actual maximum demand at each zone substation in 2007–08 (the starting point of Energex's zone substation forecasts) needed to be weather corrected.[177] MMA conducted a review of Energex's weather correction methodology for establishing the starting points for the zone substation demand forecasts. MMA noted that Energex calculated a maximum temperature coefficient[178] for each zone

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171 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p .5.
172 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 15–16.
173 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 24–27.
174 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 20.
175 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 31–33.
176 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 51–52.
177 MMA, *Review of Energex's demand forecasts*, October 2009, p. 52.
178 Maximum temperature coefficient measures the demand response to temperature increases at zone substation level in term of MW per degree.

substation to adjust for the demand response to temperature increases, as well as applying a separate adjustment based on the size of previous maximum demand to account for the size of the zone substation. MMA considered that this second adjustment tended to overestimate demand at large zone substations and underestimate demand at small zone substations because the size and customer composition of the zone substations had already been accounted for by the application of the maximum temperature coefficient.[179] However, on balance, MMA considered Energex's weather correction methodological flaws were not significant.[180]

MMA noted that Energex forecast maximum demand growth at zone substations based on linear extrapolation of annual historical data, together with judgements of asset managers. MMA was concerned that the historical data used by Energex's asset managers does not include weather normalisation and compensation for load transfers and block loads. MMA also found that the projected growth rate does not appear to be consistent with history for one out of the four zone substations it examined.[181] MMA noted that Energex used a 5 per cent threshold to define future block loads and considered this approach to be reasonable. However MMA identified some potential concerns about Energex's treatment of block loads, including the following:[182]

- all assessed block loads were assumed to have a 100 per cent coincident factor with the zone substation summer maximum demand

- all tentative block loads were assumed to proceed, with the total load spread evenly across two years.

MMA considered that these approaches were likely to result in an overestimation of block loads. MMA reviewed a limited number of block load forecasts and concluded that the forecasts appeared to be reasonable, but noted that the GFC would result in around one to two year delays for a numbers of projects.[183]

MMA found that prospective load transfers appeared to be handled well by Energex.[184]

MMA noted that the combined zone substation loads were reconciled against the system maximum demand forecasts using a trim factor. MMA considered this reconciliation is very important and noted it should significantly reduce the impact of spatial demand methodological vulnerabilities. However, MMA stated that this requires the system level forecasts to be carried out rigorously and to be based on timely inputs. MMA concluded that the imperfections in the spatial forecasts may lead to some misallocation in the location of future demand growth, but considered it had not resulted in large systematic biases in the forecasts.[185]

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179 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 52–54.
180 MMA, *Review of Energex's demand forecasts*, October 2009, p. 5.
181 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 54–55.
182 MMA, *Review of Energex's demand forecasts*, October 2009, p. 56.
183 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 56–57.
184 MMA, *Review of Energex's demand forecasts*, October 2009, p. 57.
185 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 58–59.

Ergon Energy

MMA reviewed eight zone substations within Ergon Energy's network region to assess its spatial demand forecast methodology. MMA noted that Ergon Energy's spatial demand forecasts are based on a linear trend analysis without weather correction, and spot load assessments are based on judgement.[186]

MMA noted that while Ergon Energy mentions a number of key drivers such as Gross State Product (GSP), population growth and air conditioner penetration in its description of its forecasting methodology, it does not appear that any of these key drivers, apart from new spot loads, are actually taken into account in its bottom up methodology.[187] As noted above in relation to system maximum demand forecasts, MMA does not consider that Ergon Energy systematically reconciles its bottom up forecasts with NIEIR forecasts. As a result, MMA considered that Ergon Energy's approach implicitly assumes a growth driver will remain similar to historical trend and that its forecasts will be unresponsive to recent major changes in key drivers due to the GFC and CPRS.[188] MMA therefore considered that Ergon Energy's bottom up approach to forecasting is likely to result in an unrealistic maximum demand forecast in the current environment.[189]

MMA reviewed Ergon Energy's treatment of spot loads and found that Ergon Energy does not apply a threshold limit to the size of spot loads. As a result MMA considered spot loads are likely to be double counted as they are included in both the trend line assessment and separate adjustments after that. MMA estimated the potential impacts of this double counting and found that it resulted in overestimation of maximum demand for four of the eight zone substations chosen for review. MMA noted that the impacts were unevenly distributed, with the weighted average percentage reduction across the eight zone substations equal to 2.6 per cent by 2015.[190]

MMA noted that Ergon Energy uses a probabilistic approach in assessing uncertain loads. MMA reviewed the accuracy of Ergon Energy's historical forecasts of major customers[191] based on a limited sample. Based on this review, MMA made the following observations:[192]

- there is almost inevitably a delay from when a project is first included in the planning schedule to when the load eventuates, and this delay was evident even before the GFC
- the GFC is expected to further set back projects by some two to three years
- the probabilities assigned to uncertain loads seem very high in many cases, especially when they relate to timing, and when loads do not eventuate in one year the identical forecasts are often just shifted into the following year.

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186 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 48–49.
187 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 62.
188 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 62–63.
189 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 6.
190 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 50–51.
191 The analysis includes forecasts of major customers with additional loads of 10MW from 2001 to 2009 in the Capricornia area.
192 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 56–57.

Based on the above observation, MMA considered that the judgement applied by Ergon Energy appears to have over-stated the size and the timing of large spot loads.[193]

In order to assess Ergon Energy's treatment of load transfers, MMA requested Ergon Energy to provide the history of load transfers for the eight zone substations chosen for the detailed review. In response, Ergon Energy indicated that such detailed historical information was not available.[194] MMA considered that without such fundamental information, it has serious concerns about Ergon Energy's ability to produce accurate trend forecasts.[195]

Overall, MMA concluded that Ergon Energy's spatial demand forecast methodology is flawed and likely to produce over optimistic forecasts.[196] MMA considered the maximum demand forecasts used by Ergon Energy to prepare its capex forecasts are not realistic.[197]

MMA stated that it is not possible to estimate the impacts of key drivers and the over-estimation of spot loads on spatial forecasts using Ergon Energy's methodology.[198] MMA therefore developed indicative forecasts of Ergon Energy's system maximum demand based on a top down approach.[199]

MMA estimated weather normalised 50 per cent PoE maximum demand over the period 2003–04 to 2008–09 based on information provided by Ergon Energy and most recent forecasts.[200] MMA decomposed maximum demand into the three components based on Ergon Energy's 2007 system demand load profile and separately forecast each component based on models relating each component to their key drivers, such that:[201]

- commercial and industrial maximum demand grows in proportion to growth in GSP
- residential base load (non-weather sensitive) maximum demand grows in proportion to residential customer numbers
- residential weather sensitive maximum grows in proportion to residential customer numbers and airconditioner penetration.

MMA's indicative 50 per cent PoE system maximum demand forecasts for Ergon Energy over the next regulatory control period are presented in table 6.6.

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193 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 57.
194 Ergon Energy, response, issue no: MMA EE.28, 15 September 2009, confidential.
195 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 59.
196 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 7.
197 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 8.
198 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 8.
199 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 64–65.
200 Ergon Energy, *Regulatory proposal*, July 2009, figure 33 and PL655c *EE Ergon Forecast 2008 Final Rev 2 Mar 09 GSM final*.
201 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 66.

Table 6.6: MMA indicative 50 per cent PoE maximum demand forecasts and Ergon Energy forecasts (MW)

	2010	2011	2012	2013	2014	2015
Ergon Energy forecast	2861	2967	3063	3153	3243	3330
MMA indicative forecast	2607	2693	2811	2928	3031	3121
Difference	–254	–274	–252	–225	–212	–209

Source: MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 67.

MMA considered that forecasts of Ergon Energy's maximum demand are up to 7.4 per cent lower than those produced if the impacts of changes in key drivers are properly taken into account and spot load assessments are carried out more reliably.[202] MMA stated that the difference could vary between 4.0 to 7.4 per cent depending on the amount of weather correction applied to the 2008–09 maximum demand, and input assumptions used.[203]

MMA concluded that the difference between the Ergon Energy forecasts and its forecasts at the end of the next regulatory control period is approximately equivalent to one to two years of maximum demand growth.[204]

6.5.1.3 Customer number forecasts

Energex

MMA considered that there is a strong link between customer number growth and dwelling growth, and that dwelling growth is mainly driven by population growth and changes in expected average occupancy rates[205] across the next regulatory control period. MMA reviewed Energex's residential customer number forecasts for the next regulatory control period by analysing the underlying growth drivers. This included growth in state population, dwelling numbers and changes in occupancy rate. MMA compared Energex's forecasts of these drivers against historical data from the ABS and forecasts from KPMG Econtech and NIEIR.[206]

Based on its analysis, MMA considered NIEIR's flat occupancy rate forecasts for Energex's region over the period 2008 to 2015 to be reasonable. Consequently, MMA considered that Energex's forecast customer growth of 2.2 per cent per year is consistent with the ABS base case population growth of 2.1 per cent over the period 2008 to 2015, and is therefore reasonable.[207]

Ergon Energy

MMA considered that there is a strong link between customer number growth and dwelling growth, and that dwelling growth is mainly driven by population growth and

202 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 8.
203 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 67–68.
204 MMA, *Review of Energex's demand forecasts*, October 2009, p. 8.
205 Also know as persons per dwelling.
206 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 14–18.
207 MMA, *Review of Energex's demand forecasts*, October 2009, p. 18.

changes in the occupancy rate. MMA reviewed Ergon Energy's residential customer number forecasts over the next regulatory control period by analysing the underlying growth drivers. This included growth in state population, dwelling numbers and changes in the occupancy rate. MMA compared Ergon Energy's forecasts of these drivers against historical data from the ABS and forecasts from KPMG Econtech and NIEIR.[208]

MMA noted that NIEIR's projected population growth rate of 1.7 per cent a year in Ergon Energy's region is lower compared to growth in Energex's region over the period 2002 to 2008. MMA considered that this disparity was consistent with experience over the period 2002 to 2008.[209] MMA noted that projected population growth, combined with NIEIR's projection of 0.2 per cent a year reduction in the occupancy rate in Ergon Energy's region, indicated growth in dwellings in Ergon Energy's region of around 2 per cent a year. Overall, MMA expected that the GFC would result in a slight reduction in population and dwelling growth over the next regulatory control period.[210]

MMA considered that Ergon Energy's forecast customer number growth of 1.6 per cent per year is low compared to NIEIR's dwelling growth forecast, even with the impact of the GFC taken into account, but not unrealistic. Nevertheless, MMA used a 1.8 per cent rate of annual growth in customer numbers in developing its indicative system demand forecasts, as outlined in section 6.5.1.2 of this draft decision.[211]

6.6 Issues and AER considerations

6.6.1 Maximum demand forecasts

Energex

The AER notes MMA's findings that Energex's weather correction methodology applied at the zone substation level tended to over adjust maximum demand for large zone substations and under adjust maximum demand for small zone substations, and its spatial demand forecasting methodology tended to over estimate tentative block loads, which may lead to some misallocation of future demand growth. However, the AER considers the extent of the biases appears to be moderate and will be ameliorated as a result of reconciliation with system maximum demand forecasts.

The AER notes that Energex adjusted its baseline system maximum demand forecasts (see table 6.1) because they did not reflect potential impacts from the GFC, demand management initiatives and the introduction of a CPRS.

The AER notes that the model used by Energex to produce its baseline system maximum demand forecasts appears to double count maximum demand growth due to GSP growth and air conditioner penetration, and that the absolute number of air conditioners should be used in the model to provide a better measure of air conditioner growth.

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208 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 16–20.
209 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 18.
210 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, pp. 19–20.
211 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 20.

For these reasons the AER considers that Energex's baseline system maximum demand forecasts and the model used to produce them do not provide a reasonable expectation of demand.

The AER considers that the modified version of Energex's forecasting model provided by MMA addresses the issues outlined above.[212] The AER also considers it appropriate to adjust the maximum demand forecasts produced by this model to reflect the impact of Energex's demand management initiatives. The resultant forecasts of maximum demand are presented in table 6.7

Table 6.7: MMA 50 per cent PoE system maximum demand forecasts (MW)

	2011	**2012**	**2013**	**2014**	**2015**
MMA system maximum demand forecasts (50% PoE) – MW	4882	5067	5295	5567	5828
NIEIR system maximum demand forecasts (50% PoE) – MW	5144	5378	5699	5945	6085
System maximum demand reductions arising from DM initiatives (50% PoE) – MW	–18	–40	–67	–101	–144
MMA system maximum demand forecasts adjusted for proposed DM initiatives (50% PoE) – MW	4864	5027	5228	5466	5684
NIEIR system maximum demand forecasts adjusted for proposed DM initiatives (50% PoE) – MW	5126	5338	5632	5844	5941

Source: MMA, *Review of Energex's demand forecasts*, October 2009, p. 48; and Energex, *Regulatory proposal*, July 2009, p. 154.

The AER notes that MMA's version of Energex's model produces forecasts which are significantly lower than Energex's baseline forecasts and are also lower than the NIEIR forecasts that Energex used to adjust its baseline forecasts.

Supplementary information provided by Energex

The AER received supplementary information from Energex regarding its growth related capex forecasts. This information reflected updated (June 2009) load forecasts that, according to Energex, more accurately reflect the downturn in the economy compared with the load forecasts used in its regulatory proposal.[213] Although this information was submitted too late to be fully considered by the AER (and its consultants) for the purpose of this draft decision, it does indicate that the maximum demand forecasts contained in Energex's regulatory proposal were overstated. Based on its updated analysis, Energex indicated that its baseline capex forecast should be reduced by a further $57 million (in addition to the $226 million deduction Energex included in its regulatory proposal).[214]

[212] MMA refers to this model as model B in its report to the AER. See MMA, *Review of Energex's demand forecasts*, October 2009, pp. 45–46.
[213] Energex, *Supplementary information*, 17 September 2009, confidential.
[214] Energex, *Supplementary information*, 17 September 2009, confidential.

The AER is unable to comment on the updated demand forecasts that accompanied this advice or the methodology used to develop them, as this information was not provided. In particular, it appears the revised capex figures include additional amounts to meet security of supply standards that are different to those included in Energex's regulatory proposal.[215] Nevertheless, the AER considers that the additional reduction to expenditure proposed by Energex to account for updated demand forecasts is consistent with MMA's general conclusion that the adjusted maximum demand forecasts included in Energex's regulatory proposal are too high.

The AER notes the EUAA and Origin stated that Energex's demand growth projections were compiled in September 2008 but do not include the impact of the GFC and the AER needs to ensure Energex's historical and projected demand forecasts account for the impacts of the GFC and the CPRS.

Regarding Energex's historical demand growth, MMA conducted a detailed review of historical outcomes, and expected changes in key drivers of maximum demand, such as GSP and population growth, the impacts of retail price increases and energy efficiency policies, and the stock and the penetration rate of air conditioners. MMA concluded that maximum demand growth over the next regulatory control period is expected to be lower compared to the current regulatory control period based on the likely changes in key drivers. The AER considers MMA's modified version of Energex's maximum demand model appropriately captured the historical relationship between the key drivers and maximum demand.

In relation to impacts of the GFC, the AER notes that Energex adjusted its baseline capex forecasts to reflect an updated forecast of maximum demand which better reflected GFC impacts and has since provided advice of a further adjustment to capex for this reason. The AER notes that MMA's forecasts of maximum demand are lower than Energex's forecasts, partly due to larger impacts MMA expects from the GFC. The AER considers MMA's forecasts are more realistic.

Regarding impacts from the CPRS, the AER acknowledges that the proposed introduction of the CPRS is expected to increase electricity prices to households.[216] The AER considers that that such price increases are likely to impact on energy consumption and notes a South Australian specific study by the Electricity Supply Industry Planning Council suggests maximum demand will also be impacted.[217] However, the AER notes MMA's view that while the impacts of the CPRS on maximum demand can be expected to be negative, the extent of the impacts is difficult to quantify in the absence of a Queensland specific study. Consequently, the AER disagrees with Energex's view that the CPRS has no impact on maximum demand in the short and medium term.

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, MMA's report, submissions and other material, the AER is not satisfied that Energex's forecast of maximum demand provides a realistic expectation

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[215] See section G.5.4.4 Security compliance, of this draft decision.

[216] Australian Government White Paper, *Carbon Pollution Reduction Scheme, Australia's low Pollution Future*, Vol 2, Dec 2008, p. 17.

[217] ESIPC, *Annual Planning report*, June 2008.

of demand forecast required to achieve the capex and opex objectives. The AER considers that reducing Energex's forecast maximum demand to the levels shown in table 6.8 provides a more realistic basis for determining capex and opex forecasts.

Table 6.8: AER conclusion on Energex maximum demand forecasts (MW)

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand	4864	5027	5228	5466	5684

Ergon Energy

The AER notes the EUAA's concern on the lack of clarity around Ergon Energy's demand forecasts, and the relationship between it and the forecasts produced by NIEIR. The AER notes that Ergon Energy's capex forecast is based on internally produced, bottom up, spatial demand forecasts produced in November 2007. The AER notes that Ergon Energy does not produce top down system forecasts independent of its bottom up spatial demand forecasts. Rather, its system maximum demand forecasts are derived by aggregating bulk supply and transmission connection point maximum demand projections. The AER notes that, based on the evidence provided, there appears to be no systematic reconciliation between Ergon Energy's spatial maximum demand forecasts against NIEIR's independent system forecasts based on key drivers.

The AER notes the suggestion by the EUAA and Origin that the AER should closely examine the impacts of the GFC and the CPRS on Ergon Energy's demand forecasts. The AER considers that it is not appropriate to rely only on a bottom up approach in forecasting maximum demand, particularly in the current environment when changes in key drivers of demand are expected, for example as a result of the GFC and the proposed introduction of the CPRS. The AER therefore considers that Ergon Energy's bottom up maximum demand forecasting methodology is unlikely to accurately account for the impact of changes in key drivers during the next regulatory control period.

This conclusion is supported by a comparison of Ergon Energy's 2007 forecasts with forecasts it developed in 2008 and 2009. As shown in table 6.9, the more recent forecasts suggest that Ergon Energy expects demand to grow more rapidly following the peak of the GFC. The AER notes that the growth rates implied by Ergon Energy's 2008 and 2009 forecasts are greater than trend growth in historical maximum demand. The AER also notes that the growth rates implied by Ergon Energy's 2008 and 2009 forecasts are inconsistent with the expected changes in key drivers based on MMA's assessment.

Table 6.9: Comparison of Ergon Energy's 2007, 2008 and 2009 maximum demand forecasts (MW)

	2010–11	2014–15	Increase	Growth rate
2007 forecast	2967	3330	363	2.9%
2008 forecast	3033	3496	463	3.6%
2009 forecast	2845	3467	622	5.1%

Source: Ergon Energy, *Regulatory proposal*. July 2009, p. 160.

The AER notes MMA's view that Ergon Energy's assessment of spot loads, without the application of an appropriate threshold, will double count these loads. The AER considers that MMA's detailed analysis of historical spot load forecasts provides some indication that Ergon Energy is over optimistic in forecasting the timing and the size of spot loads.[218] The AER also has concerns about Ergon Energy's ability to produce accurate spatial demand forecasts without detailed records of historical load switching activities.[219]

The AER notes that Ergon Energy highlighted that there are uncertainties surrounding the timing and the quantum of the load growth driven by mining investments, due to various economic factors over the next regulatory control period.[220] However, this downward risk does not appear to have been accounted for in Ergon Energy's forecasts, because its spatial maximum demand forecast methodology lacks responsiveness to changes in key drivers, and double counts the size of the spot loads.

The AER considers that in the absence of a system maximum demand model, it is reasonable to address Ergon Energy's methodological deficiencies at the spatial level using a top down approach. The AER considers MMA's top down forecasting model relating key drivers and maximum demand is appropriate. The AER considers that the forecasts produced with this model, presented in table 6.10, provide a more accurate forecast of Ergon Energy's maximum demand than Ergon Energy's method.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, MMA's report and other material, the AER is not satisfied that Ergon Energy's forecast of maximum demand provides a realistic expectation of demand forecast required to achieve the capex and opex objectives. The AER considers that reducing Ergon Energy's forecast maximum demand to the levels shown in table 6.10 provides a more realistic basis for determining capex and opex forecasts that would comply with the NER.

[218] MMA, *Review of Ergon Energy's demand forecasts,* October 2009, pp. 56–57.
[219] MMA, *Review of Ergon Energy's demand forecasts,* October 2009, p. 59.
[220] Ergon Energy, *Regulatory proposal*, July 2009, p. 163.

Table 6.10: AER conclusion on Ergon Energy maximum demand forecast (MW)

	2011	2012	2013	2014	2015
50 per cent PoE maximum demand	2693	2811	2928	3031	3121

6.6.2 Customer numbers forecasts

Energex

The AER notes that growth in the number of domestic customers is a key driver of Energex's total customer growth because they account for over 90 per cent of Energex's customers.[221]

The AER notes Energex's forecast of 2.1 per cent annual growth in domestic customers over the next regulatory control period is lower than the 2.3 per cent annual growth over the current regulatory control period but consistent with the historical trend. Energex's actual and forecast customer numbers are shown in figure 6.1.

The AER notes that there is a close relationship between domestic customer numbers and the number of dwellings. It considers Energex's forecast of lower customer number growth is broadly consistent with findings by the Queensland Centre for Population Research, which show annual growth in dwellings in south east Queensland of 2.4 per cent over the period 2011–2016, a reduction of 0.1 percentage points compared to the average growth rate over the period 2006–2011.[222]

The AER notes MMA's view that population growth and dwelling growth are both key drivers of customer number growth. The AER also notes MMA's findings that Energex's forecasts of annual population growth (of 2.2 per cent) and annual dwelling growth (of 2.2 per cent) over the period 2008 to 2015 are consistent with historical trend and the ABS base case projection for Queensland.

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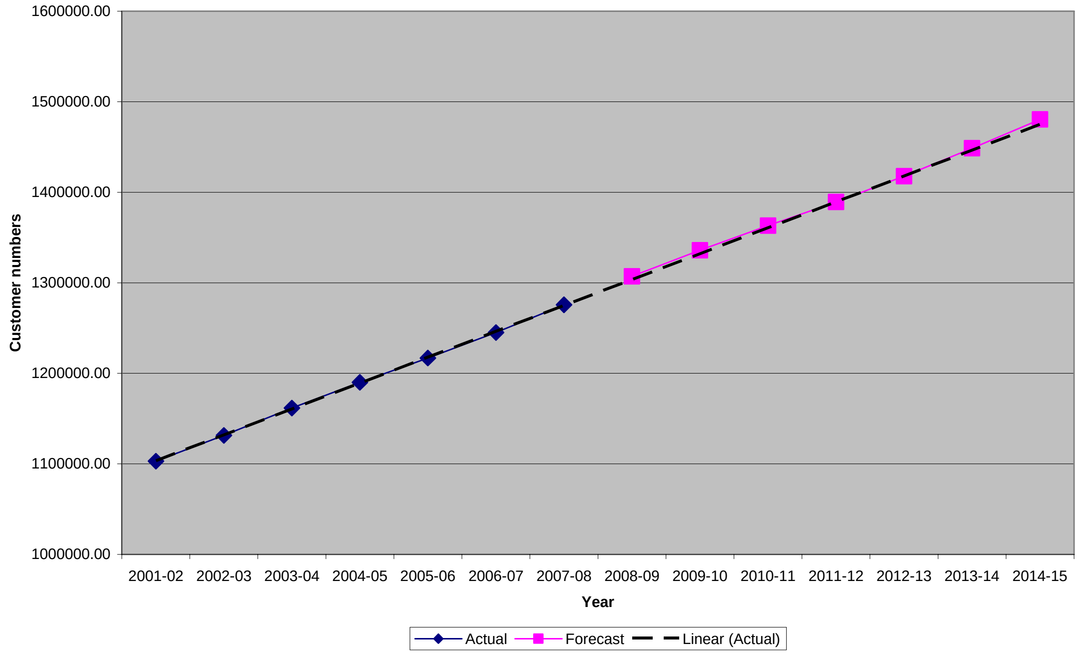
221 Based on actual 2007–08 data from Energex, *Regulatory proposal*, Attachment RSD 2.3.8(1).

222 Queensland Government, *Queensland state and regional household and dwelling projections 2006–31*, December 2008, <http://www.oesr.qld.gov.au/about–our–services/q150/historical–tables/index.shtml>

Figure 6.1: Energex actual and forecasts customer numbers



Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8 (confidential).

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, MMA's report and other material, the AER is satisfied that Energex's forecast of customer numbers reasonably reflects the capex and opex criteria, including the capex and opex objectives. In coming to this view the AER has had regard to the capex and opex factors.

Ergon Energy

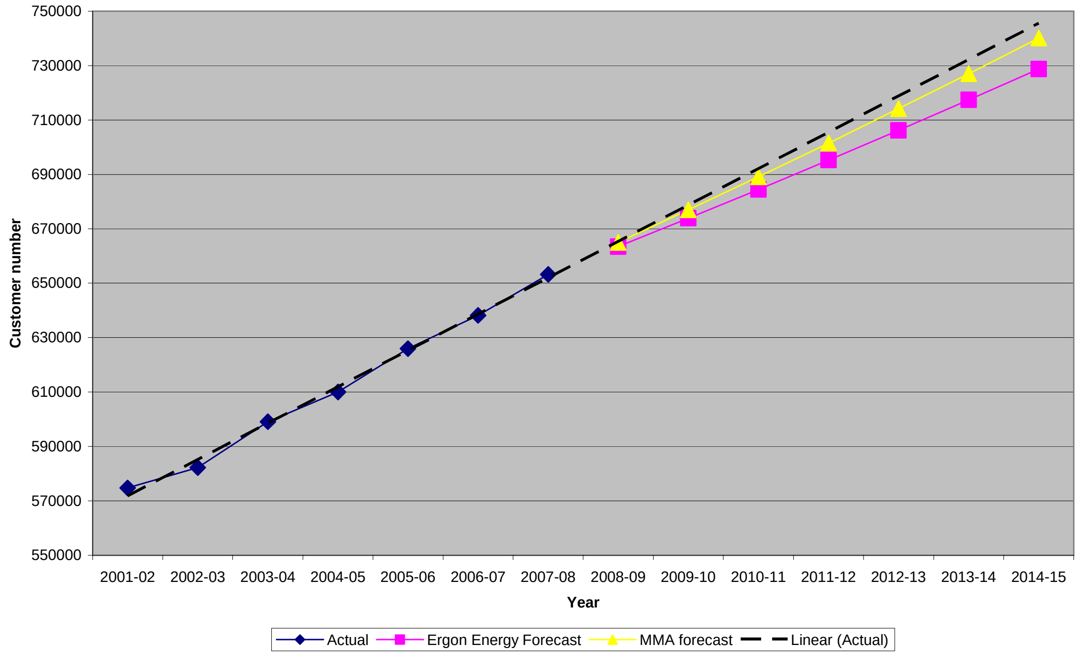
The AER notes that growth in the number of domestic customers[223] is a key driver of Ergon Energy's total customer growth because they account for around 80 per cent of Ergon Energy's customers.[224]

The AER notes that Ergon Energy's forecast of 1.6 per cent annual growth in the number of domestic customers over the next regulatory control period is lower than MMA's forecast of 1.8 per cent and recent historical growth of 2.2 per cent. Ergon Energy's actual and forecast customer numbers are shown in figure 6.2.

[223] QCA defines Standard Asset Customers (SACs) as (small) customer with average consumption of up to 100MWh per year, and (large) customer with consumption between 100 and 4000MWh. QCA, *Ergon Energy Financial and service quality performance 2007–08*, March 2009, p. 4. The domestic customer number is derived by subtracting street light appliance and watchman light connections from total numbers of SACs.

[224] Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8.

Figure 6.2 Ergon Energy's actual and forecast customer number growth



Source: Ergon Energy, *Regulatory proposal,* July 2009, RIN pro forma 2.3.8 (confidential).

The AER notes that there is a close relationship between domestic customer numbers and the number of dwellings. Research from the Queensland Centre for Population Research shows annual dwelling growth in Ergon Energy's region of 2.1 per cent over the period 2011–16,[225] a reduction of 0.4 percentage points compared to the average rate of growth over the period 2006–11.[226] The AER notes that this decline is broadly consistent with the 0.6 percentage point reduction in customer numbers that Ergon Energy is forecasting relative to recent history.

The AER notes MMA's conclusion that while Ergon Energy's customer number forecasts are not unrealistic, they appear a little low compared to forecasts from other sources. In light of the potential downward risks to population and dwelling growth associated with the impacts of the GFC, and given that the difference between Ergon Energy and MMA's forecast is relatively small, the AER considers Ergon Energy's customer number forecasts represent a realistic expectation.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal and other material, the AER is satisfied that Ergon Energy's customer number forecasts reasonably reflect the capex and opex criteria, including the capex and opex objectives. In coming to this view the AER has had regard to the capex and opex factors.

[225] Queensland Centre for Population Research, *Queensland State and regional household and dwelling projections 2006-31*, December 2008. <http://www.oesr.qld.gov.au/about-our-services/q150/historical-tables/index.shtml>

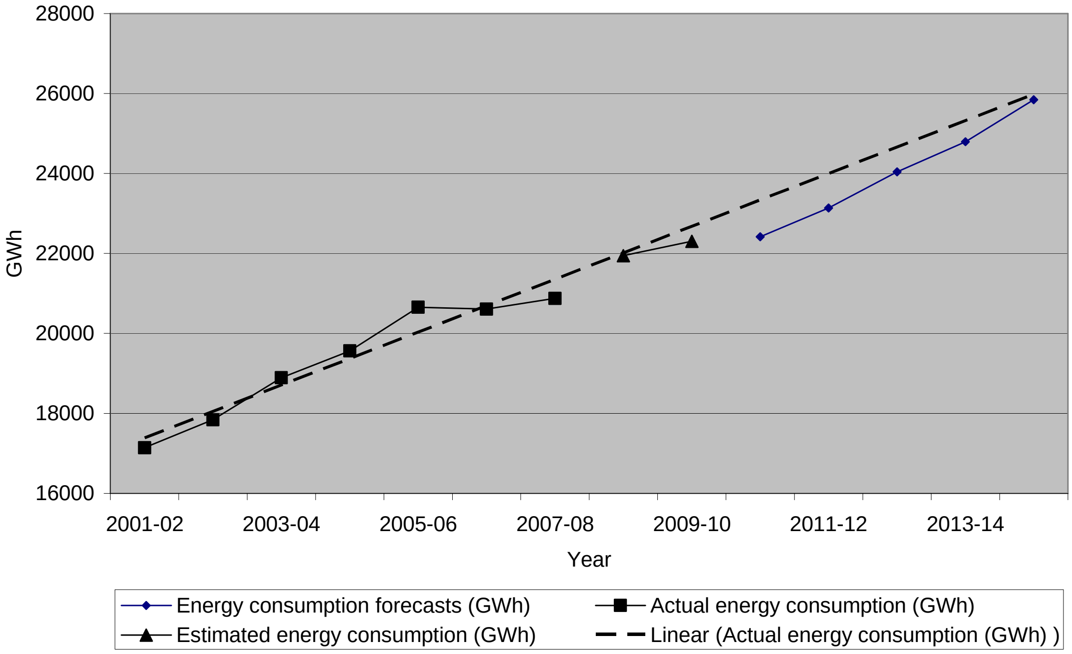
[226] Calculated based on aggregating projections from all Queensland regions apart from south east Queensland.

6.6.3 Energy consumption forecasts

Energex

The AER reviewed Energex's actual, estimated and forecast energy consumption. The AER notes that Energex's energy consumption model forecasts annual growth of 3.1 per cent over the period 2008–09 to 2014–15. This is slightly lower than the 3.4 per cent annual growth experienced over the period 2001–02 to 2007–08.

Figure 6.3: Energex actual, estimated and forecast energy consumption (GWh)



Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8 (confidential).

As shown in figure 6.3, Energex's forecast of energy consumption over the next regulatory control period starts well below the point indicated by the extrapolation of historical data. The AER considers that this is to be expected given the impact of the GFC on economic growth and energy consumption. Energex's forecast of energy consumption then moves back towards historical trends over the next regulatory control period. The AER notes that this is consistent with the Queensland government budget forecast of below trend state economic growth at the beginning of the next regulatory control period, due to the GFC, followed by recovery back to historical trend growth over the next regulatory control period.[227]

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal and other material, the AER is satisfied that Energex's forecast of energy consumption reasonably reflects the capex and opex criteria, including the capex and opex objectives. In coming to this view the AER has had regard to the capex and opex factors.

[227] Queensland Government, *Budget strategy and outlook*, 16 June 2009, p. 27.

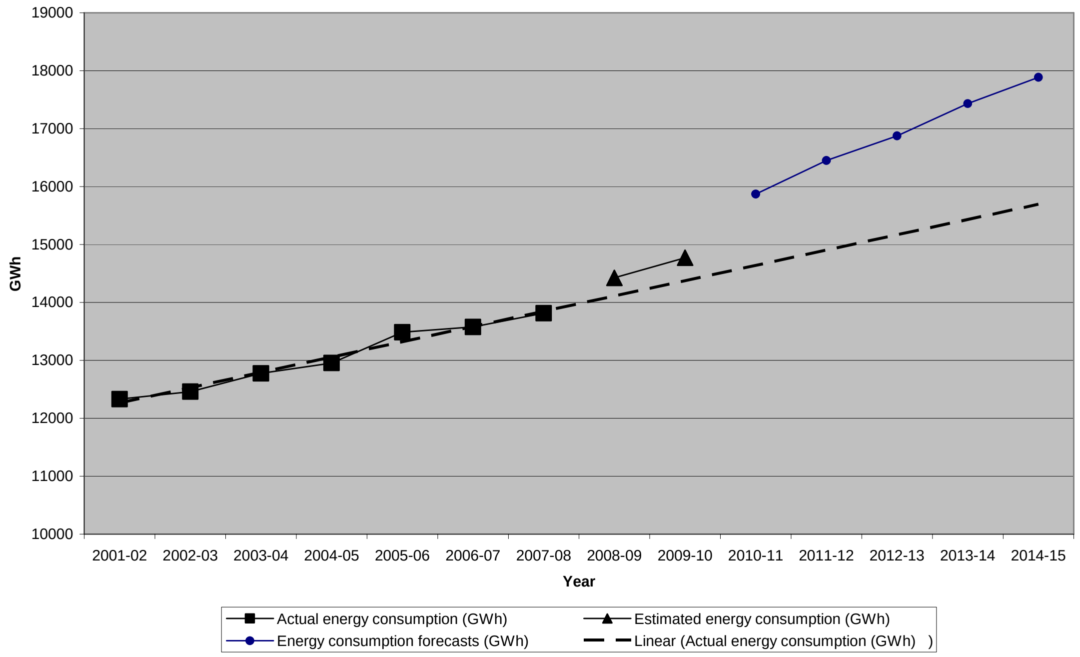
Ergon Energy

The AER reviewed Ergon Energy's energy consumption forecasts, as presented in figure 6.4 below. The AER notes that the forecast implies an annual growth rate of 3.9 per cent over the period 2008–09 to 2014–15. This is significantly higher than the 1.9 per cent rate of annual growth experienced over the period 2001–02 to 2007–08.

As shown in figure 6.4, Ergon Energy's forecast of energy consumption at the start of the next regulatory control period is well above the point indicated by the extrapolation of historical data, and this difference widens over the next regulatory control period.

The AER considers that Ergon Energy's energy consumption forecast is too high, given the current economic environment.

Figure 6.4 Ergon Energy actual, estimated and forecast energy consumption (GWh)



Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8 confidential.

The AER notes that in contrast to maximum demand forecasts, and to a lesser extent, the forecast of customer numbers, energy consumption forecasts are not relevant in the determination of Ergon Energy's revenue cap.

However, the AER notes that energy consumption forecasts are an important input to the development of Ergon Energy's network prices. To the extent that Ergon Energy's energy consumption forecasts are too high, Ergon Energy increases the chances of under–recovering its allowed revenue. While the AER's unders and overs account mechanism would allow Ergon Energy to recover this revenue in future years, there is the potential for price shocks to occur as a result. The AER therefore requires Ergon Energy to review its energy consumption forecasts before submitting its pricing proposal to the AER for approval in 2010. For the purpose of calculating indicative price impacts associated with this draft decision, the AER requires Ergon Energy to use energy consumption forecasts that better reflect the recent trend and the expected changes in key drivers over the next regulatory control period.

6.7 AER conclusion

6.7.1 Energex

The AER considers that the system and spatial maximum demand forecasts proposed by Energex do not provide a realistic expectation of the demand forecast 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 customer number and energy consumption forecasts proposed by Energex provide a realistic expectation of the demand forecast 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's conclusions on Energex's maximum demand, energy consumption and customer number forecasts over the next regulatory control period are set out in table 6.11.

Table 6.11: AER conclusions on Energex maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15
Energex					
Maximum demand (MW)	5126	5338	5633	5844	5941
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294
Energy consumption (GWh)	22 416	23 138	24 042	24 795	25 845
AER					
Maximum demand (MW)	4864	5027	5228	5466	5684
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294
Energy consumption (GWh)	22 416	23 138	24 042	24 795	25 845

6.7.2 Ergon Energy

The AER considers that the system and spatial maximum demand, and energy consumption forecasts proposed by Ergon Energy do not provide a realistic expectation of the demand forecast 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 customer number forecasts proposed by Ergon Energy provide a realistic expectation of the demand forecast 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's conclusions on Ergon Energy's maximum demand, and customer number forecasts over the next regulatory control period are set out in table 6.12.

Table 6.12: AER conclusions on Ergon Energy's maximum demand and customer number

	2010–11	2011–12	2012–13	2013–14	2014–15
Ergon Energy					
Maximum demand (MW)	2967	3063	3153	3243	3330
Customer numbers	684 469	695 242	706 204	717 356	728 706
AER					
Maximum demand (MW)	2693	2811	2928	3031	3121
Customer numbers	684 469	695 242	706 204	717 356	728 706

6.8 AER draft decision

In accordance with clause 6.12.1(10) the other appropriate amounts, values or inputs to be input to the PTRM for Energex are the AER maximum demand, customer number and energy consumption forecasts specified in table 6.11 of this draft decision.

In accordance with clause 6.12.1(10) the other appropriate amounts, values or inputs to be input to the PTRM for Ergon Energy are the AER maximum demand and customer number forecasts specified in table 6.12 of this draft decision.

7 Forecast capital expenditure

7.1 Introduction

This chapter sets out the AER's conclusions on forecast capex allowances for the Qld DNSPs for the next regulatory control period. It also:

- discusses the framework the AER has applied in assessing each proposal
- discusses the outcomes of the current regulatory control period
- provides a general overview of the proposals
- lists comments made by stakeholders on the proposals
- summarises the AER's main considerations and responses to stakeholder comments.

The AER's conclusions and the estimate of forecast capex allowances for the Qld DNSPs during the next regulatory control period are set out in section 7.9 of this chapter. A complete explanation of the Qld DNSPs' proposals and the AER's considerations for each are outlined in appendices F and G of this draft decision. This chapter is to be read in conjunction with these appendices.

7.2 Regulatory requirements

Under clause 6.12.1(3) of the NER, the AER must make a decision to accept, or reject and form its own estimate of, the total of forecast capex included in the building block proposal of each Qld DNSP in accordance with the capex objectives and the capex criteria and factors outlined in clause 6.5.7 of the NER.

7.2.1 Capex objectives

Clause 6.5.7(a) of the NER provides that a DNSP must include the total forecast capex for the regulatory control period in order to achieve the following capex objectives:

> (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
>
> (4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

7.2.2 Capex criteria and factors

Clause 6.5.7(c) of the NER also provides that the AER must accept the capex forecast included in a DNSP's regulatory proposal if it is satisfied that the total of the capex forecast for the regulatory control period reasonably reflects:

> (1) the efficient costs of achieving the capex objectives
>
> (2) the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capex objectives
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

In making this assessment the AER must have regard to the capex factors in clause 6.5.7(e) of the NER:

> (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) 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 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
>
> (10) the extent the DNSP has considered, and made provision for, efficient non– network alternatives.

Clause 6.5.7(d) of the NER states that, if the AER is not satisfied that a DNSP's forecast capex reasonably reflects the capex criteria, then the AER must not accept the forecast capex in a building block proposal. If the AER does not accept the total forecast capex proposed by a DNSP, clause 6.12.1(3)(ii) of the NER requires the AER to include in its draft decision:

> …an estimate of the total of the DNSP's required capex for the regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

7.3 AER approach to assessment

In determining whether the Qld DNSPs'capex forecasts reasonably reflects the capex criteria while having regard to the capex factors, the AER's approach to assessment has been to determine and examine whether:

- the governance frameworks, capex policies and procedures are likely to result in investment decisions, on which the capex proposals are based, are consistent with the capex objectives
- the methods and assumptions used to develop the capex proposal (including demand forecasts and estimates of unit costs), are robust and reflect a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives
- the estimates of real cost escalators and their application reflect a reasonable expectation of input cost forecasts
- the projects and programs that form part of the regulatory proposals generally reflect the capex criteria, including with respect to their scope, timing and costs
- the capex programs are deliverable and are therefore commensurate with what a prudent DNSP would require to achieve the capex objectives.

Overall these considerations are intended to assist the AER 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.

This approach is similar to that applied by the AER to electricity transmission network service providers (TNSPs) under chapter 6A of the NER, which largely mirror the requirements in chapter 6 of the NER. However, the application of this approach to the Qld DNSPs is different as the characteristics of distribution networks, specifically the larger number of individual projects and programs, means it is not possible or practical for the AER to undertake a more detailed review. Specifically:[228]

- while a range of the Qld DNSPs' projects and programs were reviewed by the AER and its consultants, the AER's overall assessment has placed less reliance on individual project reviews, in contrast to its approach for TNSPs
- due to the limitations of reviewing a large number of projects in detail, relatively more reliance has been placed on a review of the Qld DNSPs policies and procedures and the underlying assumptions such as demand forecasts and unit cost estimates, to gauge the reasonableness of the proposed capex allowances
- with assistance from its consultant, the AER has considered more general factors (e.g. trends in asset age, faults etc) and methods (e.g. expenditure modelling) in examining investment proposed at lower voltages in the network

[228] The AER is considering the regulatory proposal of ETSA Utilities concurrently with that of the Qld DNSPs.

- where appropriate, the AER and its consultants have examined departures from identified trends in historical expenditure
- the AER has compared and contrasted the Qld DNSPs' forecast changes in generic input costs with those proposed by ETSA Utilities.

7.4 Current period outcomes

This section summarises the expenditure outcomes of the Qld DNSPs with respect to the allowances set by the QCA, to identify whether any cost drivers were not identified for the current regulatory control period that should be recognised when examining the proposals for the next regulatory control period.

In aggregate, the Qld DNSPs are expected to exceed their combined regulated capex allowance by approximately $1179 million ($2009–10) or 16 per cent of the allowances set by the QCA.[229] Around 70 per cent of the total overspend is attributable to Ergon Energy. Table 7.1 shows the capex outcomes in the current regulatory control period for each of the Qld DNSPs. The actual and proposed capex of the Qld DNSPs are shown in figures 7.1 and 7.2.

Table 7.1: Capex outcomes, Qld DNSPs ($m, 2009–10)

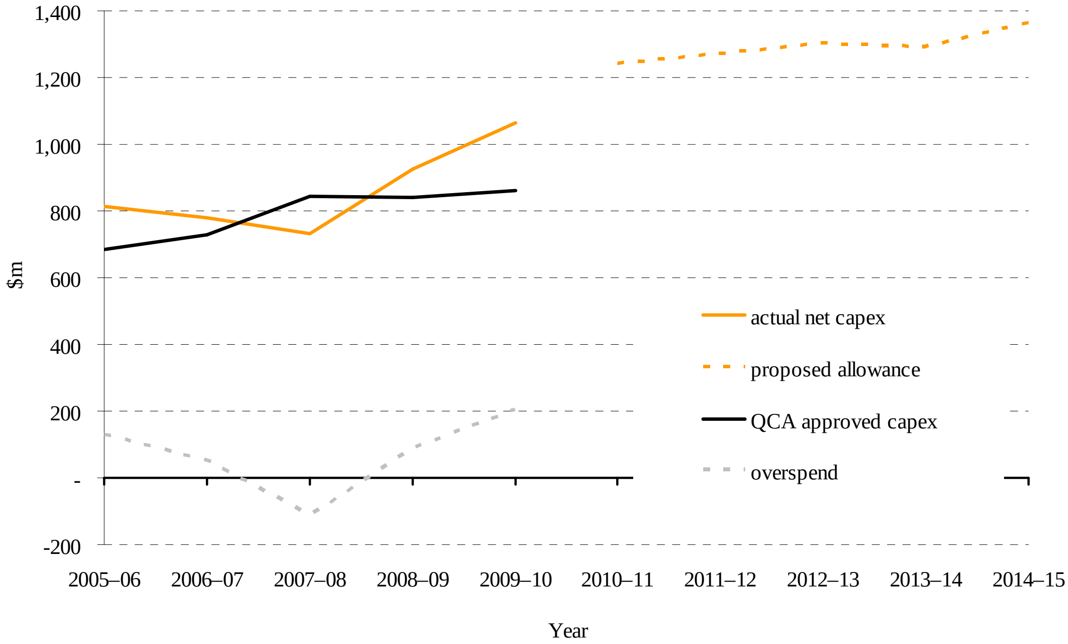
	2005–06	2006–07	2007–08	2008–09 (estimate)	2009–10 (estimate)	Total
Regulatory allowance						
Energex	685.5	729.3	844.3	839.3	860.6	3959.0
Ergon Energy	597.6	627.5	663.1	661.4	657.3	3206.9
Actual net capex						
Energex	813.6	779.9	731.4	926.0	1065.2	4316.1
Ergon Energy	732.3	825.3	843.9	750.4	876.8	4028.7
Overspend						
Energex	128.1	50.6	–112.9	86.7	204.7	357.1
Ergon Energy	134.7	197.8	180.7	89.0	219.5	821.8

Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1; and Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1. Converted to real terms using ABS inflation data.

Note: Totals may not add due to rounding.

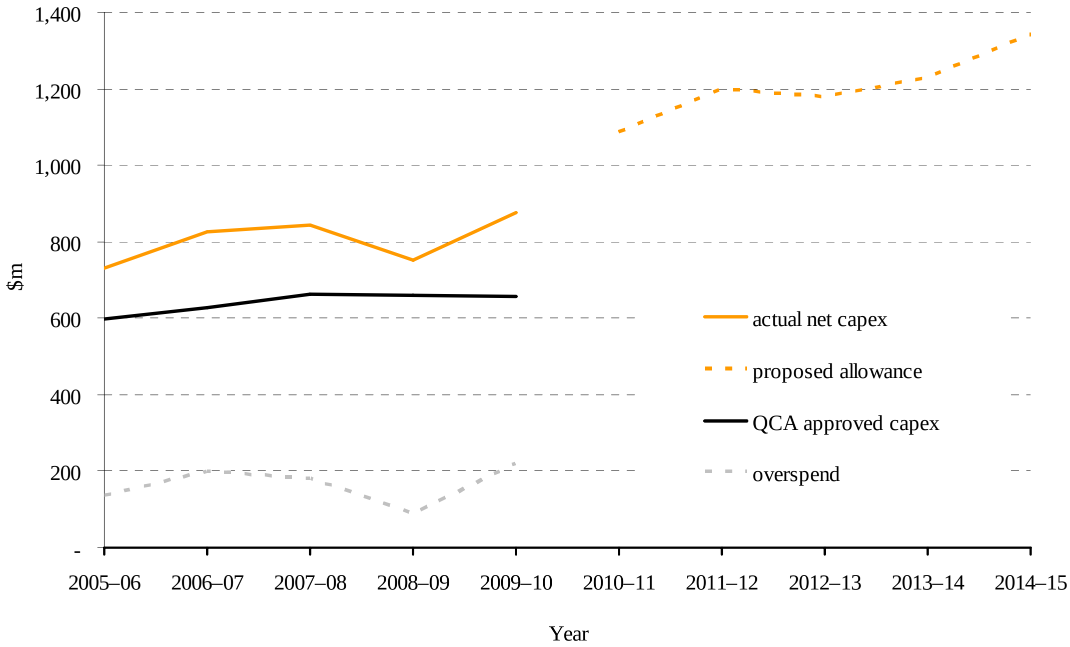
[229] QCA, *Final Determination: Regulation of electricity distribution*, April 2005.

Figure 7.1.: **Energex actual and proposed capex ($m, 2009–10)**



Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

Figure 7.2.: **Ergon Energy's actual and proposed capex ($m, 2009–10)**



Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

The reasons identified for the overspends include:

- Energex stated its overspend is mainly driven by demand related expenditure due to increased commercial and industrial customer activity and continued high levels of sub-division and high-rise building activity[230]

- Ergon Energy stated its overspend was driven by the growth in customer-initiated capital works, rising costs, and one-off events such as Tropical Cyclone Larry.[231]

The AER is not required to conduct a full prudency assessment of past expenditure, but can have regard to previous outcomes as allowed by the capex factors. In terms of the implications for its review of forecasts, the AER observes that:

- the overall significant overspend in total capex across the current period has been driven strongly by higher than anticipated levels of demand related and non-system expenditure, more than making up for underspends in asset replacement and reliability/quality improvements

- asset replacement expenditure is expected to grow significantly in the last year of the current regulatory control period. This reverses underspends in all previous years of the regulatory period. This growth is expected to persist into the next regulatory period.

In conclusion, the AER considers that the major reasons for the observed overspend are known to the Qld DNSPs and is satisfied these reasons have been taken into account when developing their current regulatory proposals. This improves the likelihood that the DNSPs have presented a complete case on which the AER is able to assess the proposals against the capex criteria.

7.5 Queensland DNSP regulatory proposals

The Qld DNSPs forecast total capex of $6466 million ($2009–10) and $6033 million ($2009–10) for the next regulatory control period. This is approximately 50 per cent (in real terms) higher than the expected capex in the current regulatory control period. The amounts proposed by the Qld DNSPs are set out in table 7.2 and figure 7.3 illustrates the proposed capex for the Qld DNSPs in comparison to their actual capex in the current regulatory control period.

[230] QCA, *Energex's financial and service quality performance 2005–06*, March 2007, p. 10; and QCA, *Financial and service quality performance 2006–07, Energex*, March 2008, p. 10.

[231] QCA, *Ergon Energy's financial and service quality performance 2005–06*, March 2007, p. 9; and QCA, *Financial and service quality performance 2006–07, Ergon Energy*, March 2008, p. 9, and QCA, *Financial and service quality performance 2007–08, Ergon Energy*, March 2009, p. 12.

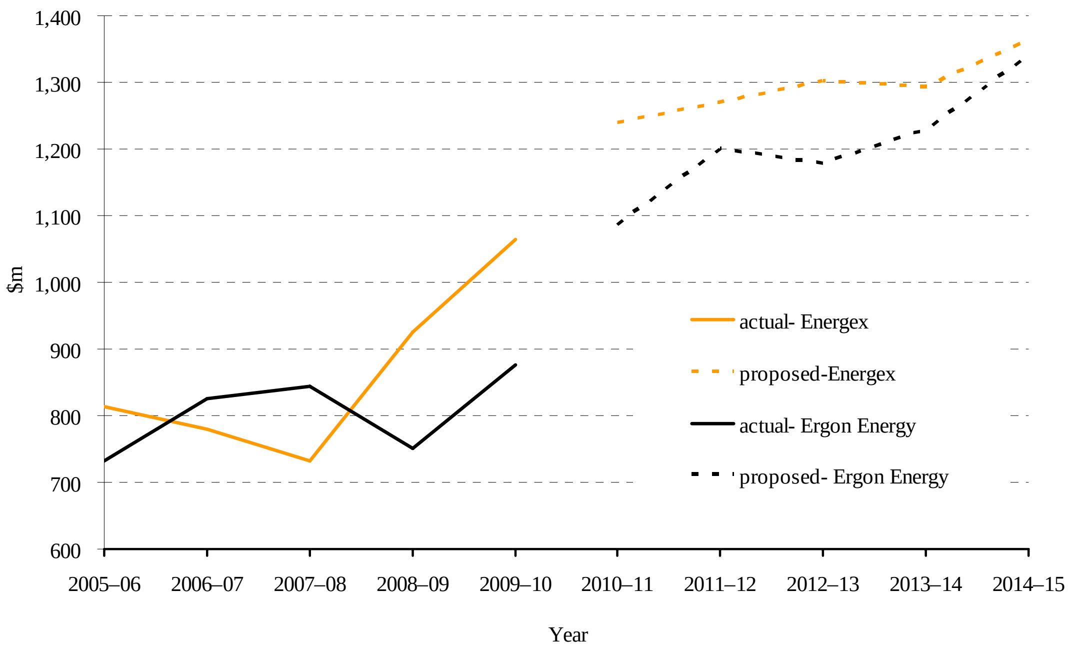
Table 7.2: Qld DNSP proposed capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0
Ergon Energy	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9

Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1; and Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1. Converted to real terms using ABS inflation data.

Note: Totals may not add due to rounding.

Figure 7.3: Actual and proposed capex, Energex and Ergon Energy ($m, 2009–10)



Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1; and Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1. Converted to real terms using ABS inflation data.

The reasons provided by Energex for the increase in its forecast capex include:[232]

- growth capex – due to increases in corporation initiated augmentation (CIA) expenditure including assets such as bulk supply and zone substations, and overhead and underground cables, and customer initiated capital works (CICW) expenditure to connect customers to the network
- asset replacement and renewal capex – increasing need to replace assets approaching the end of their life

[232] Energex, *Regulatory proposal*, July 2009, pp. 202–205.

- reliability and quality of service enhancement capex – to improve reliability by installing fault isolating devices in the network, building small rural substations and rebuilding rural overhead lines

- security compliance capex – to augment the network and reduce loading on lines and substations to a level such that failure of one component does not result in a sustained outage to customers.

Ergon Energy identified the following key drivers for the increases in its forecast capex:[233]

- growth capex – due to the increase in corporation initiated augmentation expenditure to build additional network capacity to meet demand growth and address forecast system constraints, and the increase in customer initiated capital works expenditure to meet forecast levels of customer connections work[234]

- asset replacement capex – replace failed assets and reduce average asset age to minimise future interruptions[235]

- reliability and quality improvements capex – compliance with the minimum service standard requirements under the Electricity Industry Code.

7.6 Submissions

Submissions from the Energy Users Association of Australia (EUAA), Origin Energy retail Pty Ltd (Origin), Queensland Council of Social Service (QCOSS) and SPA Consulting Engineers (SPA) raised concerns regarding the following aspects of the Qld DNSPs' capex proposals:

- **Efficiency and prudence of capex** – submissions sought assurances that the capex proposed by Energex and Ergon Energy are efficient.[236] The EUAA was critical of the AER's approach to benchmarking and stated that the AER must properly benchmark the DNSPs' expenditure against that of an efficient DNSP as required under the NER.[237] The EUAA also noted the very significant expansion of expenditure by Ergon Energy on corporate property and stated that the AER should investigate this carefully to determine its purpose, relevance and benefit.[238]

- **Augmentation capex** – the EUAA observed that growth in Energex's capex between 2001–02 and 2009–10 has been much higher than growth in peak demand and customer numbers and suggested the AER should carefully examine what has been achieved before contemplating further increases in

[233] Ergon Energy, *Regulatory proposal*, July 2009, p. 27.
[234] Ergon Energy, *Regulatory proposal*, July 2009, pp. 203 and 206.
[235] Ergon Energy, *Regulatory proposal*, July 2009, p. 196.
[236] EUAA, *Submission to the AER on Energex and Ergon Energy regulatory proposals for the period 2010–2015*, 28 August 2009, p. 20; and QCOSS, *Response to Queensland distribution network service providers' regulatory proposals*, August 2009, p. 2.
[237] EUAA, *Submission to the AER*, 28 August 2009, pp. 13–17.
[238] EUAA, *Submission to the AER*, 28 August 2009, p. 21.

expenditure.[239] Origin stated that the growth in capex proposed by Energex for the next regulatory period is well above growth in peak demand and customer numbers and urged the AER to apply detailed scrutiny of the basis of the proposed increase in capex.[240]

- **Replacement capex –** the EUAA stated that Energex's arguments on expenditure to replace ageing assets do not appear to be supported by the asset age profile.[241]

- **Security and reliability capex –** the EUAA sought assurances that the security and reliability capex proposed by Energex is reasonable and responsible.[242] SPA stated that the distribution networks should be constructed economically to deliver reliability standards demanded by the community.[243] Origin noted that Energex will not meet its N–1 security standard by the end of the next regulatory control period and that it would be useful if Energex could explain how far it has progressed in meeting the standard.[244]

- **Demand management –** submissions sought assurances that the demand management activities of the Qld DNSPs are focused on capacity constrained areas of the network and that the benefits of such activities outweigh the costs.[245]

7.7 Consultant review

The AER engaged PB to provide independent reviews of the prudence and efficiency of the Qld DNSPs' capex proposals.[246] In assessing whether the capex proposed by the Qld DNSPs is prudent and efficient, PB has:[247]

- assessed whether the Qld DNSP is acting efficiently in accordance with good electricity industry practice through a review of capital governance, policy and procedures, cost estimating practices, specific reviews of certain expenditures, and the deliverability of the proposed works program

- assessed whether there is a justifiable need for the proposed investment within each expenditure category

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239 EUAA, *Submission to the AER*, 28 August 2009, p. 19.
240 Origin, *Queensland DNSPs*, August 2009, p. 4.
241 EUAA, *Submission to the AER*, 28 August 2009, p. 20.
242 EUAA, *Submission to the AER*, 28 August 2009, p. 19.
243 SPA, *Submission to the AER*, August 2009, p. 2.
244 Origin, *ETSA Utilities*, August 2009, p. 4.
245 EUAA, *Submission to the AER*, 28 August 2009, pp. 20–21, QCOSS, *Submission to the AER*, 28 August 2009, pp. 3–4.
246 PB, *Review of Energex regulatory proposal for the period July 2010 to June 2015 for Australian Energy Regulator (Report – Energex)*, October 2009, p. 1 and PB, *Review of Ergon Energy regulatory proposal for the period July 2010 to June 2015 for Australian Energy Regulator (Report – Ergon Energy)*, October 2009, p. 1.
247 PB, *Report – Ergon Energy*, October 2009, pp. 4 and 5; and PB, *Report – Energex*, October 2009, pp. 4 and 5.

- after confirming the need for an investment, assessed whether all reasonable options have been considered and the most efficient investment selected to satisfy that need

- where an investment is based on assumptions about future conditions, assessed whether those assumptions are reasonable.

For Energex, PB concluded that the proposed total capex is prudent and efficient, except for the proposed building program, and the forecast of peak demand (based on McLennan Magasanik Associates (MMA) demand forecast). PB recommended adjustments to the proposed capex allowance in these areas.[248]

For Ergon Energy, PB concluded that the proposed total capex is not prudent and efficient. PB identified specific issues such as the growth capex, asset replacement capex, reliability and quality improvement capex and non-system capex. In these instances, PB recommended reductions in the proposed capex allowance.[249]

The capex allowances resulting from PB's recommended adjustments are provided in table 7.3.

Table 7.3: PB's recommended forecast capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex						
Energex proposed capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0
PB recommendation	1087.2	1186.1	1225.0	1235.0	1285.8	6019.1
Ergon Energy						
Ergon Energy's proposed capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9
PB recommendation	822.6	880.4	946.9	1021.2	1107.1	4778.2

Source: PB, *Report – Energex*, October 2009, pp. xiv–xv; and PB, *Report – Ergon Energy*, October 2009, pp. xiii–xiv.
Note: Totals may not add due to rounding.

PB's specific comments with respect to the Qld DNSPs' capex proposals are outlined in appendices F and G of this draft decision.

7.8 Issues and AER consideration

This section is a summary of issues and AER's consideration of the following aspects of Qld DNSPs' regulatory proposal:

- policies and procedures

[248] PB, *Report – Energex*, October 2009, p. xiii.
[249] PB, *Report – Ergon Energy*, October 2009, p. xii.

- methods and assumptions
- efficiency in scope, timing and costs
- cost accumulation
- the deliverability of the forecast capex program.

Further details of these aspects are provided in appendices F and G (capex), and chapter 6 (demand forecast).

7.8.1 Policies and procedures

7.8.1.1 Qld DNSP regulatory proposals

Energex

Energex's capex planning activities are undertaken through the network development and management framework, which consists of Energex's network strategy and a range of procedures, plans, standards and policy documents.[250]

At the operational level, the development of projects and programs including options analysis, scoping, estimation and approvals processes is undertaken in accordance with the relevant Business Management System (BMS) process document. Compliance with the BMS is monitored annually through external audit processes.[251]

The key documents which summarise Energex's proposed capital investment plans are the network development plan for the sub–transmission network and distribution backbone, and the distribution capital plan for the distribution network, including customer driven works.[252]

In relation to capital governance, Energex stated that its network planning and expenditure processes are subject to a three tier capital governance process, covering different investment timeframes.[253]

The Energex Board's Network Technical Committee oversees the outcomes of the network development and management framework. Program outcomes and variations to the approved work program are monitored by the Program of Work Governance Committee.[254]

Ergon Energy

Ergon Energy's framework for capex planning activities is described through its asset management plan. Ergon Energy stated that the asset management plan provides a framework for the efficient management of its electricity infrastructure assets over their life cycle, balancing costs against service obligations and stakeholder expectations.

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[250] Energex, *Regulatory proposal*, July 2009, p. 76.
[251] Energex, *Regulatory proposal*, July 2009, p. 77.
[252] Energex, *Regulatory proposal*, July 2009, pp. 67–68.
[253] Energex, *Regulatory proposal*, July 2009, p. 76.
[254] Energex, *Regulatory proposal*, July 2009, p. 76–77.

The key documents which summarise Ergon Energy's capex plans are the sub–transmission network augmentation plans and distribution network augmentation plans for each of Ergon Energy's six geographic regions, and the asset equipment plans which document the maintenance and replacement strategies for 26 asset equipment types.[255]

Ergon Energy stated that it has a comprehensive framework for the development and prioritisation of its asset investment program, supported by a hierarchy of governance bodies and approval authorities.[256]

7.8.1.2 Consultant review

PB reviewed the Qld DNSPs' capex planning and governance policies and procedures as a critical element of assessing the prudence and efficiency of the capex proposed for the next regulatory control period. PB reviewed the framework in which decisions are made to determine whether the relevant policies and procedures align with good electricity industry practice and the approach taken by the Qld DNSPs is likely to result in appropriate expenditure.

Energex

In relation to Energex's capex planning and governance policies and procedures, PB concluded that:

- Energex's capitalisation policy is reasonable and pragmatic and is consistently applied throughout the organisation[257]
- Energex's capital governance framework is consistent with good electricity industry practice and is likely to lead to prudent investment decisions[258]
- Energex's planning criteria are pragmatic and representative of good electricity industry practice[259]
- the options analysis process presents a variety of options, which are assessed on the basis of net present value. A sensitivity analysis is undertaken to ensure that the preferred option is robust in terms of changes to scope or cost[260]
- the cost estimation processes and procedures reflect good electricity industry practice and implementation should lead to a prudent and efficient outcome[261]
- Energex's consideration of efficient non–network solutions and demand management alternatives is consistent with good electricity industry practice[262]

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[255] Ergon Energy, *Regulatory proposal*, July 2009, pp. 134–135.
[256] Ergon Energy, *Regulatory proposal*, July 2009, p. 152.
[257] PB, *Report – Energex*, October 2009, p. 18.
[258] PB, *Report – Energex*, October 2009, p. 24.
[259] PB, *Report – Energex*, October 2009, p. 35.
[260] PB, *Report – Energex*, October 2009, pp. 28–29.
[261] PB, *Report – Energex*, October 2009, p. 29.
[262] PB, *Report – Energex*, October 2009, p. 31.

- the application of the demand forecasts has been appropriately incorporated into capex forecasts[263]

- the application of the condition based risk management (CBRM) model to Energex's replacement and renewal capex program leads to a prudent and efficient capex proposal[264]

- the revised network security standards that Energex proposed for the next regulatory control period represent good electricity industry practice.[265]

Ergon Energy

In relation to Ergon Energy's capex planning and governance policies and procedures, PB concluded that:

- Ergon Energy's capitalisation policy is reasonable and is applied consistently throughout the organisation[266]

- Ergon Energy's capital governance framework accords with the principles of good electricity industry practice in general, although the framework is still to be fully implemented[267]

- Ergon Energy's planning criteria are in accord with good electricity industry practice, are appropriately applied and suitable for the purposes of developing the relevant elements of the capex forecast[268]

- the quality, completeness and robustness of Ergon Energy's options analysis varied considerably, such that while Ergon Energy's procedure is prudent in requiring options analysis to be conducted, the inconsistent and incomplete application of the process leads to results that do not clearly demonstrate efficient investment[269]

- the prudent application of demand forecasts in the development of Ergon Energy's proposed capex investments was only partially demonstrated and evidenced by the business documentation[270]

- in current practice, Ergon Energy rarely recognises efficient non–network alternatives as potential options when considering anticipated network constraints. However, Ergon Energy is currently developing its non–network alternative capability, and has pilot projects and trials in progress. These align broadly with good electricity industry practice[271]

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263 PB, *Report – Energex*, October 2009, p. 50.
264 PB, *Report – Energex*, October 2009, p. 50.
265 PB, *Report – Energex*, October 2009, p. 51.
266 PB, *Report – Ergon Energy*, October 2009, p. 22.
267 PB, *Report – Ergon Energy*, October 2009, pp. 28–29.
268 PB, *Report – Ergon Energy*, October 2009, p. 40.
269 PB, *Report – Ergon Energy*, October 2009, p. 40.
270 PB, *Report – Ergon Energy*, October 2009, p. 41.
271 PB, *Report – Ergon Energy*, October 2009, p. 41.

- Ergon Energy’s key asset replacement policies and procedures generally accord with the principles of good asset management and good electricity industry practice, however asset replacement practices are not consistently implemented[272]

- Ergon Energy’s policies and procedures as they relate to the management of reliability and quality of supply improvement are generally in accord with good electricity industry practice.[273]

7.8.1.3 AER considerations

The AER reviewed the Qld DNSPs’ capex planning and governance framework, and sought advice from PB as to the appropriateness of the key plans, policies and procedures underpinning the capex proposals.

Energex

The AER reviewed Energex’s capex governance framework, including relevant documentation provided by Energex with respect to its capital budgeting, evaluation, approval, monitoring and review procedures, and delegation structures. On the basis of its review, the AER considers Energex’s capex governance framework is robust and provides adequate assurance that investment decisions are likely to be prudent and efficient.

Having considered Energex’s capex planning and governance framework, and advice from PB, the AER is satisfied that Energex’s policies and procedures for capex planning and governance demonstrate a sufficient level of assurance and good practice such that their application is likely to lead to prudent and efficient investment decisions. On this basis, the AER is satisfied that Energex’s capex planning and governance processes are consistent with the achievement of the capex objectives.

Ergon Energy

The AER reviewed Ergon Energy’s capex governance framework, including relevant documentation provided by Ergon Energy with respect to its capital budgeting, evaluation, approval, monitoring and review procedures, and delegation structures. On the basis of its review and advice from PB, the AER considers that Ergon Energy’s capex governance framework, though still in the process of being fully implemented, is generally appropriate and provides adequate assurance that investment decisions are likely to be prudent and efficient.

Having considered Ergon Energy’s capex planning and governance framework, and advice from PB, the AER is satisfied that Ergon Energy’s policies and procedures for capex planning and governance generally support the view that their application is likely to lead to prudent and efficient investment decisions. However, the AER is concerned at the extent to which relevant policies or procedures do not appear to have been consistently applied in practice, and the implications this may have for the effective and efficient identification of investment priorities in Ergon Energy’s capex

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[272] PB, *Report – Ergon Energy*, October 2009, p. 44.
[273] PB, *Report – Ergon Energy*, October 2009, p. 58.

proposal. The AER considers this to be relevant in determining whether Ergon Energy's forecast capex reasonably reflects the capex criteria.

7.8.2 Methods and assumptions

7.8.2.1 Qld DNSP regulatory proposals

Demand forecast and methodologies

Energex prepared both spatial and system maximum demand forecasts on its network over the next regulatory control. Energex validated it own forecasts against system maximum demand forecasts prepared by the National Institute of Economic and Industrial Research (NIEIR).[274] Energex also engaged ACIL Tasman to review its 10 year demand forecasting approach and indicated that it incorporated some of the recommendations to arise from this.[275] Energex stated that it completed preliminary modelling based on the most recent NIEIR forecast (April 2009) to estimate the impacts of the global financial crisis (GFC) and the proposed introduction of a carbon emission reduction scheme. Energex also accounted for the impacts of its demand management initiatives in adjusting its baseline maximum demand forecasts.[276]

Ergon Energy forecast maximum demand on its network for the next regulatory control period using a bottom up method based on internally produced forecasts of maximum demand at the zone substation level of the network (also known as 'spatial' demand forecasts). Ergon Energy used a top down forecast of its network maximum demand from NIEIR to review, check and, where necessary, amend its internally prepared demand forecasts.[277] Ergon Energy's network has been summer peaking over the previous and current regulatory control periods and is forecast to be summer peaking in the next regulatory control period.

Further details on the Qld DNSPs' demand forecasts are provided in chapter 6.

Unit cost assumptions

The Qld DNSPs used internal estimating tools to develop unit costs for specified, standard capex tasks, or 'building blocks', which formed the basis of the majority of their capex proposals.

Energex develops the scope of individual capex projects by selecting appropriate building blocks to deliver the required network outcome. The cost of each project is then based on the estimated cost of the building blocks required.[278] Energex indicated that project cost estimates are reviewed at key stages in the planning, design and construction process.[279] Energex also indicated that the standard designs in its building block estimating program are periodically tested and reviewed against market and industry developments. Evans and Peck independently reviewed the unit

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274 Energex, *Regulatory proposal*, July 2009, p. 138.
275 Energex, *Regulatory proposal*, July 2009, p. 138.
276 Energex, *Regulatory proposal*, July 2009, pp. 149–154.
277 Ergon Energy, *Regulatory proposal*, July 2009, p. 174.
278 Energex, *Regulatory proposal*, July 2009, p. 199.
279 Energex, *Regulatory proposal*, July 2009, p. 198.

rates Energex used to develop its capex forecasts and found that, on balance, Energex's unit rates fell within the range that Evans and Peck expected.[280]

Ergon Energy's unit costs are derived from an internally developed estimating tool which takes account of factors such as the cost of internal and external labour and materials associated with specified capex tasks.[281] Ergon Energy stated that its unit rates are efficient because around 80 per cent of its capex costs are externally procured and therefore market tested. An independent review of its unit rates by Sinclair Knight Merz Pty Ltd (SKM) suggests that the unit rates that Ergon Energy used to develop its capex forecasts are well within an acceptable range.[282]

7.8.2.2 Consultant review

Demand forecast and methodologies

As detailed in chapter 6, the AER engaged MMA to provide assistance in reviewing the demand forecasts used by the Qld DNSPs in their regulatory proposals. As the Qld DNSPs are regulated under a revenue cap, maximum demand forecasts are key inputs into capex forecasts. The focus of MMA's review has therefore been the Qld DNSPs' maximum demand forecasts and methodologies. MMA also reviewed customer number forecast methodologies and forecasts. [283]

MMA found that Energex's baseline system maximum demand forecast model appears to double count the impacts of gross state product on maximum demand.[284] MMA also considered that the absolute number of air conditioners should be used[285] instead of the penetration rate as one of the explanatory variables in the multi linear regression analysis to accurately account for the underlying growth in air conditioners.[286] For these reasons, MMA concluded that Energex's forecast model is not suitable for forecasting 50 per cent probability of exceedence (PoE) maximum demand.[287] MMA also found Energex's spatial demand forecasting methodology to be flawed, in that it may lead to some misallocation of future demand growth. However, MMA considers that the extent of the biases appears to be moderate and will be ameliorated as a result of reconciliation with global forecasts.[288]

MMA identified some potential concerns about Energex's treatment of block loads and considered that the treatment was likely to result in an overestimation of block loads.[289] MMA reviewed a limited number of block load forecasts and concluded that

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280 Evans and Peck, *Energex Review of 2010/11 to 2014/15 Submission to the Australian Energy Regulator for Compliance with National Electricity Rules*, June 2009, p. 28, confidential.
281 Ergon Energy, *Regulatory proposal*, July 2009, p. 327.
282 Ergon Energy, *Regulatory proposal*, July 2009, p. 330.
283 MMA, *Review of Energex's demand forecasts*, October 2009, p. 1; and MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 1.
284 MMA, *Review of Energex's demand forecasts*, October 2009, p. 39.
285 The absolute number of air conditioners is calculated by multiplying the number of customers by the air conditioning penetration rate.
286 Since it is possible for the numbers of air conditioner to grow while the penetration rate remains constant.
287 MMA, *Review of Energex's demand forecasts*, October 2009, p. 4.
288 MMA, *Review of Energex's demand forecasts*, October 2009, pp. 58–59.
289 MMA, *Review of Energex's demand forecasts*, October 2009, p. 56.

the forecasts appear to be reasonable, but noted that the GFC would result in around one to two year delays for a numbers of projects.[290]

MMA noted that Ergon Energy does not produce top down system forecasts independent of its bottom up spatial demand forecasts.[291] MMA considered that there appears to be no systematic reconciliation between Ergon Energy's spatial maximum demand forecasts against NIEIR's independent system forecasts based on key drivers.[292] For these reasons MMA considered that Ergon Energy's approach is unresponsive to recent changes in key drivers due to the GFC and carbon pollution reduction scheme (CPRS).[293]

MMA noted that Ergon Energy's spatial demand forecasts are based on a linear trend analysis without weather correction, and judgement based spot load assessments.[294] MMA has serious concerns about Ergon Energy's ability to produce accurate trend forecasts without detailed records of historical load transfer activities. MMA found that Ergon Energy's assessment of spot loads, without the application of an appropriate threshold, is likely to double count these loads.[295] MMA reviewed the accuracy of Ergon Energy's historical forecasts of major loads based on a limited sample, and found that the judgement applied by Ergon Energy tended to over-state the size and the timing of large spot loads.[296] For these reasons MMA considered that Ergon Energy's spatial demand forecast methodology is flawed and likely to produce over-optimistic forecasts.[297] MMA therefore developed indicative forecasts of Ergon Energy's system maximum demand based on regression analysis to address these issues. MMA concluded that the difference between the Ergon Energy and MMA forecasts is approximately equivalent to one to two years of system MD growth.[298]

Unit cost assumptions

The AER engaged PB to provide an independent view on the prudence and efficiency of Qld DNSPs' capex proposals. While not required to provide a comprehensive benchmarking review of unit costs, PB was required, as part of developing its view on the efficiency of investment decisions, to undertake a review of unit costs where it considered this was necessary.

PB reviewed the estimating computer program used by Energex to develop cost estimates for its capex program. PB noted that Energex's approach includes the development of building blocks used in the construction of the network and that these include all labour, material and contract work. PB also noted that Energex's cost estimating system is used to prepare estimates for various stages in the planning, design and construction process and that it allows for variation of estimates where known factors make it likely that the original approval will be exceeded. PB found a consistent approach had been applied to the reviewed projects and that Energex had

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290 MMA, *Review of Energex's demand forecasts*, October 2009, p. 56.
291 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 65.
292 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 5l.
293 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 62.
294 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 39.
295 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 50.
296 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 56.
297 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 7.
298 MMA, *Review of Ergon Energy's demand forecasts*, October 2009, p. 8.

included sensitivity analysis on changes in cost in the cost estimating process.[299] Based on its review, PB concluded that the processes and procedures Energex has used to estimate costs in developing its capex forecasts reflect good electricity industry practice and that their implementation should lead to a prudent and efficient outcome.[300]

PB reviewed Ergon Energy's processes and procedures for cost estimation, including the development of unit costs for Ergon Energy's 'specified work' and the range of methods used to develop costs for Ergon Energy's 'unspecified work'. PB noted that an independent review by SKM found that Ergon Energy's unit costs were within a nominated tolerance range of +/– 15 per cent and that SKM concluded the unit rates were 'reasonable and efficient cost estimates for the assets'. Based on its review, PB concluded that the processes and procedures Ergon Energy uses in relation to cost estimation reflect good electricity industry practice.[301]

7.8.2.3 AER considerations

Demand forecast and methodologies

The AER's detailed consideration of the Qld DNSPs' demand forecasts and forecasting methodologies is outlined in chapter 6.

As a result of the AER's consideration of Energex's regulatory proposal, MMA's report and other material, the AER is not satisfied that Energex's forecast of maximum demand reasonably reflects a realistic expectation of the demand forecast required to achieve the capex and opex objectives. As such, the AER is not satisfied that Energex's forecast of required capex and opex reflect the capex and opex criteria, including the capex and opex objectives. The AER notes the suggestion by the EUAA and Origin that the AER should examine Energex's historical demand growth and the impacts of the GFC and the CPRS. The AER considers the analysis and review as discussed in chapter 6 of this draft decision addresses these concerns.

The AER considers that reducing Energex's forecast maximum demand to the levels shown in table 7.4 will result in expenditure that reasonably reflects the capex and opex criteria, including the capex and opex objectives, and is the minimum adjustment necessary for demand forecasts to comply with the NER. In coming to this view the AER has had regard to the capex and opex factors.

Table 7.4: AER conclusion on Energex maximum demand forecasts (MW)

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand (MW)	4864	5027	5228	5466	5684

As a result of the AER's consideration of Ergon Energy's regulatory proposal, MMA's report and other material, the AER is not satisfied that Ergon Energy's

299 PB, *Report – Energex*, October 2009, p. 29.
300 PB, *Report – Energex*, October 2009, p. 29.
301 PB, *Report – Ergon Energy*, October 2009, p. 33.

forecast of maximum demand reasonably reflects a realistic expectation of the demand forecast required to achieve the capex and opex objectives. As such, the AER is not satisfied that Ergon Energy's forecast of required capex and opex reflect the capex and opex criteria, including the capex and opex objectives. The AER notes submissions from the EUAA and Origin on the lack of clarity around Ergon Energy's demand forecasts, and the suggestion that the AER should examine Ergon Energy's historical demand growth and the impacts of the GFC and the CPRS. The AER considers the analysis and review as discussed in chapter 6 addresses these concerns. The AER considers that reducing Ergon Energy's forecast maximum demand to the levels shown in table 7.5 will result in expenditure that reasonably reflects the capex and opex criteria, including the capex and opex objectives, and is the minimum adjustment necessary for demand forecasts to comply with the NER. In coming to this view the AER has had regard to the capex and opex factors.

Table 7.5: AER conclusion on Ergon Energy maximum demand forecast (MW)

	2011	**2012**	**2013**	**2014**	**2015**
50 per cent PoE maximum demand (MW)	2693	2811	2928	3031	3121

Unit cost assumptions

The AER notes Energex and Ergon Energy rely on external competitive tender processes for the provision of capex related materials and services. The AER considers that this approach is likely to result in efficient costs being incurred by a DNSP.

The AER notes that Energex's cost estimation system appears well designed to provide efficient cost estimates. The AER also notes Evans and Peck concluded that, on balance, Energex's unit rates fall within its expected range. The AER notes that PB found the processes and procedures Energex used to estimate costs are robust and consistent. Having considered Energex's forecast capex program and cost estimation processes, and advice from PB and Evans and Peck, the AER is satisfied that Energex's cost estimation processes for capex reflect a realistic expectation of cost inputs and are therefore likely to result in efficient cost forecasts. On this basis the AER is satisfied that Energex's cost estimation processes are consistent with the capex objectives.

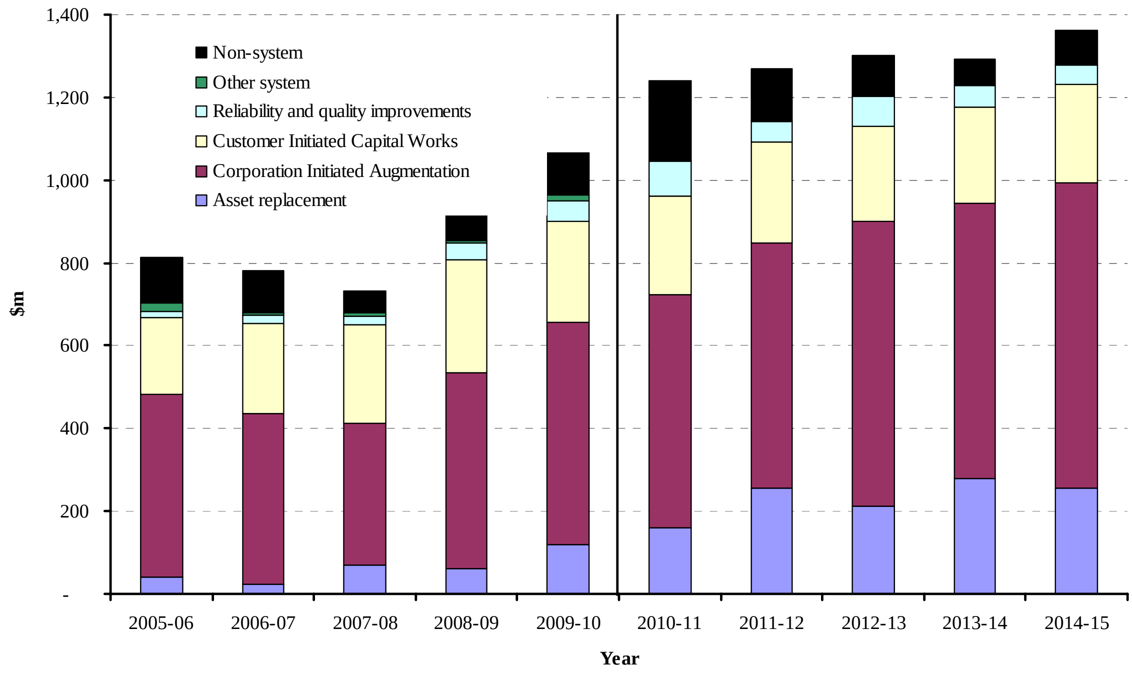
The AER notes that 85 per cent of Ergon Energy's proposed capex is based on unit costs independently reviewed by SKM. The AER notes SKM's conclusion that Ergon Energy's unit cost estimates are reasonable and efficient. The AER also notes PB's conclusion that the processes and procedures Ergon Energy uses in relation to cost estimation reflect good electricity industry practice. Having considered Ergon Energy's forecast capex program and cost estimation processes, and advice from PB and SKM, the AER is satisfied that Ergon Energy's cost estimation processes for capex reflect a realistic expectation of cost inputs and are therefore likely to result in efficient cost forecasts. On this basis, the AER is satisfied that Ergon Energy's cost estimation processes are consistent with the capex objectives.

7.8.3 Efficiency in scope, timing and costs

7.8.3.1 Qld DNSP regulatory proposals

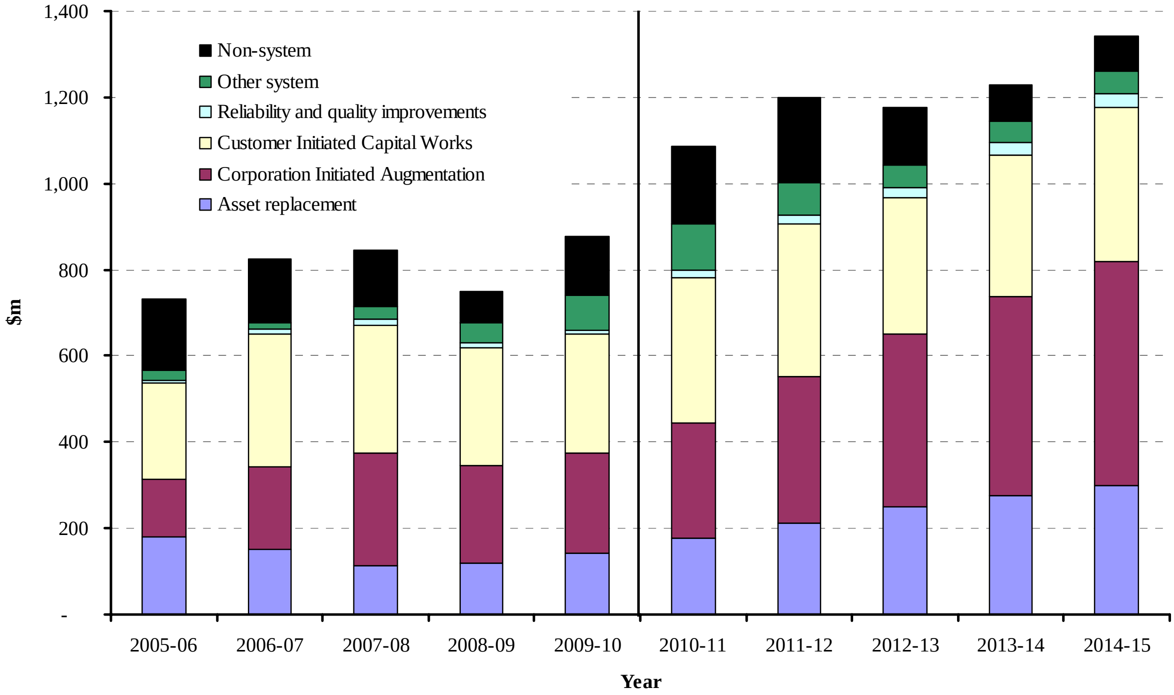
The key categories of capex proposed by each Qld DNSP are compared to those in the current regulatory control period in figures 7.4 and 7.5. The major elements of the proposals are discussed below.

Figure 7.4: Energex's actual and proposed capex by driver ($m, 2009–10)



Source: Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

Figure 7.5: Ergon Energy's actual and proposed capex by driver ($m, 2009–10)



Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

Growth capex

Energex has proposed growth capex of $2613 million ($2009–10) which is around 29 per cent above that spent in the current regulatory control period. Around 55 per cent of growth capex is augmentation expenditure, including assets such as bulk supply and zone substations, and overhead and underground cables. The remaining 45 per cent of growth capex is for connecting residential and other customers excluding larger commercial and industrial customers. (The design and construction of connection assets for larger customers is an alternative control service and is not included in forecast capex).[302]

Ergon Energy has proposed growth capex of $3686 million ($2009–10), representing a 52 per cent increase from the current regulatory control period.[303] Approximately 54 per cent of the proposed growth capex is attributed to the corporation initiated augmentation work to build additional network capacity that will meet demand growth and address forecast system constraints.[304] The remaining 46 per cent of growth capex is attributed to customer initiated capital works required to meet forecast levels of customer connections work.[305]

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302 Energex, *Regulatory proposal*, July 2009, p. 202.
303 Derived from Ergon Energy, *Regulatory proposal*, July 2009, RIN template 2.2.1.
304 Ergon Energy, *Regulatory proposal*, July 2009, p. 203.
305 Ergon Energy, *Regulatory proposal*, July 2009, p. 206.

Asset replacement capex

Energex proposed $1165 million ($2009–10) in renewal and replacement capex, which is a 271 per cent increase on expenditure in the current regulatory control period. Energex stated that it has a significant number of aged assets that require refurbishment or replacement and that it uses CBRM methodology to predict asset replacement. Energex's asset renewal and replacement projects and programs for the next regulatory control period will focus on:[306]

- supporting structures for powerlines
- equipment on the distribution network
- identified 11 kV feeders
- sub-transmission 33 kV and 110 kV lines
- bulk supply and zone substation plant
- obsolete and aging telecommunications and supervisory control and data acquisition (SCADA) equipment.

Ergon Energy proposed $1214 million ($2009–10) in asset replacement expenditure which represents an increase of around 72 per cent from the current regulatory control period, and will comprise around 20 percent of the forecast capex program. This category includes expenditure relating to 'defects' as well as condition based work. It noted this expenditure involves replacing failed assets and reduce average asset lives to minimise future interruptions.[307]

Reliability capex

Energex proposed $306 million ($2009–10) of reliability and quality of service capex. This is approximately 114 per cent (in real terms) higher than that of the current regulatory control period. Energex stated the driver for this increase is to improve reliability by installing fault isolating devices in the network, building small rural substations and rebuilding rural overhead lines.[308]

Ergon Energy proposed $122 million ($2009–10) in reliability and quality improvements capex which is around 131 per cent (in real terms) above the current regulatory control period. Ergon Energy noted that the expenditure proposed for the next regulatory control period is required to meet the increasingly onerous minimum service standard requirements under the Electricity Industry Code and to address worst performing feeders.[309]

Security compliance capex (Energex only)

Energex forecast security compliance capex of $1817 million ($2009–10), which accounts for 28 per cent of Energex's total forecast capex program and represents an

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306 Energex, *Regulatory proposal*, July 2009, pp. 203–204.
307 Ergon Energy, *Regulatory proposal*, July 2009, p. 196.
308 Energex, *Regulatory proposal*, July 2009, pp. 204–205.
309 Ergon Energy, *Regulatory proposal*, July 2009, p. 211.

increase of 39 per cent (in real terms) compared to the current regulatory control period. Energex stated this capex category is based on projects to augment the network and reduce loading on lines and substations to a level such that failure of one component does not result in a sustained outage to customers.[310]

Other system capex (Ergon Energy only)

Ergon Energy proposed $331 million ($2009–10) in other system capex which represents an increase of 75 per cent (in real terms) compared to the current regulatory control period. This expenditure relates to a number of projects and programs, including:[311]

- the UbiNet project
- retrofitting auto-reclose and sensitive earth fault protection on existing feeders
- single wire earth return (SWER) augmentation work
- undergrounding
- other programs, which comprise low voltage fuse retrofits, low voltage spreaders, substation security, oil containment bunding and alternate substation alternating current supplies.

Non-system capex

Energex's proposed non–system capex of $564 million ($2009–10) includes expenditure on end–use computing assets, motor vehicles, land and buildings, and tools and equipment. Non–system capex represents approximately 9 per cent of the total forecast capex program. This expenditure is driven by a range of programs and projects to replace aged equipment and facilities, address the extensive use of temporary accommodation, and manage and mitigate safety and health risks in the workplace.[312]

For the next regulatory control period, Ergon Energy proposed $679 million ($2009–10) in non-system capex. This is approximately 4 per cent (in real terms) higher when compared with the current regulatory control period. It attributed this expenditure to the purchase of necessary tools and equipment, information and communication technology (ICT) systems upgrades and replacements, and the need to bring property assets up to an acceptable standard.[313]

7.8.3.2 Consultant review

PB adopted a phased approach to review Qld DNSPs's proposed capex. The process was designed to provide broad coverage of the capex proposal while enabling a more

[310] Energex, *Regulatory proposal*, July 2009, pp. 202–203.
[311] Ergon Energy, *Regulatory proposal*, July 2009, pp. 219–221.
[312] Energex, *Regulatory proposal*, July 2009, pp. 205–206.
[313] Ergon Energy, *Regulatory proposal*, July 2009, pp. 222–235.

detailed examination of key issues, as required. The phased approach adopted by PB involved:[314]

- detailed desk-top review of the regulatory proposal
- onsite meetings with staff to discuss essential elements of its regulatory proposal
- development of preliminary view on key issues
- discussion and agreement with the AER to a scope of works for the focussed review stage
- further discussions with DNSP staff to establish full understanding of specific expenditure items.

PB's key findings for Energex

PB has found Energex's proposed system capex to be prudent and efficient, except for the forecast expenditures relating to growth. PB's key findings are as follows:[315]

- Energex's capital governance is consistent with good electricity industry practice
- the processes and procedures Energex has used reflect good electricity industry practice and implementation should lead to a prudent and efficient outcome
- Energex's consideration of non–network solutions and demand management alternatives is consistent with good electricity industry practice
- the electricity demand forecasts set out in Energex's regulatory proposal have been appropriately incorporated into forecast expenditures
- Energex's proposed capex for growth has been reduced by $289 million ($2009–10), based on reduced demand forecasts as recommended by MMA.

For Energex's non-system capex, PB found the proposed level of expenditure not to be prudent and efficient. In particular, PB found that the need and timing for the extensive proposed building program was not sufficiently demonstrated. PB recommended a reduction of $158 million ($2009–10) to the proposed land and buildings capex in the next regulatory control period. Energex's proposed capex for ICT, tools and equipment and fleet are assessed as being prudent and efficient by PB.[316]

PB's key findings for Ergon Energy

Based on its review, PB has found $4355 million of the proposed system capex to be prudent and efficient. PB recommends that the system capex allowance for the next

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[314] PB, *Report – Energex*, October 2009, p. 4.
[315] PB, *Report – Energex*, October 2009, pp. xiii–xiv.
[316] PB, *Report – Energex*, October 2009, pp. xiv–xv.

regulatory control period should be reduced by $999 million from the levels proposed by Ergon Energy. PB's key findings are as follows:[317]

- Ergon Energy's capital governance is generally consistent with good electricity industry practice
- the options analysis included in Ergon Energy's business case documentation lacks robustness, generally does not consider non–network alternatives, and includes limited NPV analysis to demonstrate the efficiency of the selected option
- the planning criteria used by Ergon Energy are aligned with good electricity industry practice, however, demand forecast application is only partially demonstrated
- asset replacement policies and procedures are in line with good electricity industry practice, however, asset replacement practices are not consistently implemented
- reliability and quality improvement planning follows many of the elements of good electricity industry practice
- an adjustment in expenditure is recommended in the following categories for the reasons outlined:
  - a reduction of $526 million to the corporation initiated augmentation growth capex forecast as a result of deferring this expenditure for 18 months
  - a reduction of $318 million to the Customer Initiated Capital Works growth capex forecast as PB is of the view that the forecast has not been sufficiently substantiated
  - a reduction of $119 million to the asset replacement capex forecast as PB's view is that the volume forecasts underpinning the forecasts were not demonstrated to be prudent
  - a reduction in reliability and quality improvement capex of $35 million, as the increase arising from the feeder improvement program has not been demonstrated to be efficient.

For non-system capex, PB found Ergon Energy's proposed level of expenditure not to be prudent and efficient. PB has recommended the following reductions:[318]

- a reduction of $65 million to the proposed ICT capex to reflect removal of costs associated with the Change Program for which no information was provided to demonstrate prudence or efficiency

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[317] PB, *Report – Ergon Energy*, October 2009, pp. xii–xiii.
[318] PB, *Report – Ergon Energy*, October 2009, pp. xiii–xiv.

- a reduction of $191 million to the proposed property capex which reflects a business as usual approach. In the view of PB, the need and timing for the proposed building program is only partially demonstrated and, in general, alternatives have not been well considered.

7.8.3.3 AER considerations

Growth capex

Energex
The AER considered the documentation provided by Energex in support of its regulatory proposal, and sought advice from PB as to the prudence and efficiency of the proposed expenditures.

The AER considered PB's findings in relation to Energex's policies and procedures for planning the proposed growth capex support a view that the need, timing and efficiency of the proposed expenditures have been appropriately established by Energex.

The AER notes that peak demand growth is a key driver of growth related expenditure.[319] The AER received submissions from the EUAA and Origin questioning the relationship between the historical and proposed growth in Energex's capex and growth in peak demand and customer numbers. These submissions urged the AER to apply detailed scrutiny to the basis of the proposed increase in capex.[320]

In this regard, the AER sought advice from MMA and PB about the reasonableness and application of Energex's peak demand forecasts. The AER notes PB's view that the demand forecast set out in Energex's regulatory proposal has been appropriately incorporated into forecast expenditures.[321] However, the AER notes the advice from MMA that Energex's forecasting model contains a bias making it unsuitable for forecasting system peak demand, and that peak demand forecasts are overstated to the extent of 200MW to 300MW.[322]

As discussed in chapter 6 of this draft decision, the AER has concluded that Energex's forecast of maximum demand does not provide a realistic expectation of the demand forecast required to achieve the capex objectives set out in the NER. The AER is therefore not satisfied that Energex's forecast demand related capex reasonably reflects a realistic expectation of the demand forecast. On this basis, the AER considers it appropriate that Energex's proposed demand related capex be reduced to account for Energex's overestimation of forecast maximum demand in the next regulatory control period.

The AER notes PB's recommendation that Energex's proposed demand related capex should be reduced by 20 per cent in each year of the next regulatory control period to reflect a smoothed reduction in growth capex equivalent to one year of peak demand related expenditure. The AER considers such an approach to be reasonable for

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319 Energex, *Regulatory proposal*, July 2009, p. 137.
320 EUAA, *Submission to the AER*, August 2009, p 19; and Origin, *Queensland DNSPs*, August 2009, p. 4.
321 PB, *Report – Energex*, October 2009, p. xiv.
322 MMA, *Review of Energex's maximum demand forecasts*, Sept 2009, p. 4.

estimating the level of growth capex which reasonably reflects a realistic expectation of forecast demand. The AER requested Energex model the impact of the AER's decision on growth capex. Energex advised that the adjustment to forecast growth capex is a reduction of $289 million.[323]

The AER received submissions from the EUAA and QCOSS seeking assurances that Energex's demand management activities are focused on capacity constrained areas of the network and that the benefits of such activities outweigh the costs.[324]

The AER reviewed the extent to which Energex has considered, and made provision for, efficient non–network alternatives in its demand driven capex proposal, and also sought PB's advice in this regard. On the basis of its review, and the advice from PB, the AER is satisfied that Energex has appropriately considered, and made provision for, efficient non–network alternatives in its demand driven capex proposal, and that Energex is in line with good electricity industry practice in this regard.

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's growth related capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed growth capex by $289 million[325] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

Ergon Energy

The AER reviewed Ergon Energy's growth related capex proposal for the next regulatory control period. The AER considered the documentation provided by Ergon Energy in support of its regulatory proposal, and sought advice from PB as to the prudence and efficiency of the proposed expenditures.

The AER received submissions from the EUAA and QCOSS seeking assurances that Ergon Energy's demand management activities are focused on capacity constrained areas of the network and that the benefits of such activities outweigh the costs.[326] The AER notes that Ergon Energy has included all proposed demand management expenditure as part of its opex proposal, which is discussed in chapter 8 of this draft decision.[327] Nevertheless, the AER reviewed the extent to which Ergon Energy has considered, and made provision for, efficient non–network alternatives in its growth capex proposal, and also sought PB's advice in this regard.

On the basis of its review, and advice from PB, the AER considers that the extent to which Ergon Energy has considered and made provision for efficient non–network alternatives as part of its capex proposal is limited. However, noting Ergon Energy's

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323 Energex, response to the AER, 11 November 2009, confidential.

324 EUAA, *Submission to the AER*, August 2009, pp. 20-21; QCOSS, *Submission to the AER*, August 2009, pp. 3–4.

325 See table 7.6 for the treatment of the indirect cost component of this deduction.

326 EUAA, *Submission to the AER*, August 2009, pp. 20-21; QCOSS, *Submission to the AER*, August 2009, pp. 3–4.

327 Ergon Energy, *Regulatory proposal*, July 2009, p. 313.

approach of including proposed demand management expenditure as part of its opex proposal, the AER is generally satisfied that Ergon Energy does consider, and make provision for, efficient non–network alternatives and demand management initiatives.

The AER considers that PB's findings in relation to Ergon Energy's policies and procedures for planning the proposed corporate initiated augmentation capex support a view that the need, timing and efficiency of the proposed capex has not been established by Ergon Energy. The AER is not satisfied that the forecast growth related capex reflects the efficient costs that a prudent operator in the circumstances of Ergon Energy would require to achieve the capex objectives set out in the NER.

The AER notes that peak demand growth is a key driver of growth related expenditure.[328] The AER sought advice from MMA and PB about the reasonableness and application of Ergon Energy's peak demand forecasts. As discussed in chapter 6 of this draft decision, following advice from MMA the AER concluded that Ergon Energy's peak demand forecasts are not realistic and are likely to be overstated to the extent of one to two years of peak demand growth. The AER is therefore not satisfied that Ergon Energy's forecast demand related CIA capex reasonably reflects a realistic expectation of the demand forecast required to achieve the capex objectives set out in the NER. The AER considers it appropriate that Ergon Energy's proposed demand related CIA capex be reduced to account for its overestimation of forecast maximum demand in the next regulatory control period. The AER requested Ergon Energy model the impact of the AER's decision on CIA capex. Ergon Energy advised that the adjustment to forecast CIA capex is a reduction of $526 million ($2009–10).[329]

In relation to the proposed CICW capex, the AER considers that the robustness of Ergon Energy's forecast CICW capex is not supported by Ergon Energy's forecasting methodology. For example, the AER considers that the application of dwelling stock growth forecasts in order to forecast growth in commercial and industrial connections is not appropriate. The AER considers that Ergon Energy's CICW capex be forecast on the basis of a business as usual approach, based on Ergon Energy's average historical connection numbers and costs, and forecast customer growth rate. The AER requested Ergon Energy model the impact of the AER's decision on CICW capex. Ergon Energy advised that the adjustment to forecast CICW capex is a reduction of $318 million ($2009–10).[330]

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's growth related capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed growth capex by $844 million[331] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

328 Ergon Energy, *Regulatory proposal*, July 2009, p. 17.
329 Ergon Energy, response to the AER, 17 November 2009, confidential.
330 Ergon Energy, response to the AER, 17 November 2009, confidential.
331 See table 7.7 for the treatment of the shared cost component of this deduction.

Asset replacement capex

Energex

The AER notes that Energex has increased its focus on a condition based risk management approach for asset replacement and renewal rather than on the age of the asset alone. The AER considers a condition based replacement program is more efficient than one based solely on asset age.

The AER also notes that Energex's internal planning processes confirm when a replacement is required (based on condition) and ensure that various site works are aligned. The AER therefore considers Energex's approach to planning and processes are prudent and efficient.

The AER notes that Energex uses the CBRM model to predict asset replacement in the longer term. The AER has not conducted a detailed review of the CBRM model but notes its ability to predict the replacement of assets based on condition, physical location and the risk to its network. The AER has accepted PB's advice that the use of the CBRM model is likely to lead to prudent and efficient asset replacement.

The AER notes the EUAA's concerns that Energex's asset age profile does not support its proposed replacement and renewal capex program. Energex's forecast replacement and renewal capex program is developed using its CBRM model which uses several technical inputs (such as asset age) constants (for example location and proximity to the coast) and risk related inputs which apply a value to risks such as environmental and loss of supply. Asset age is just one of a variety of inputs used to predict replacement. Asset replacement is predicted by the CBRM model based on overall condition rather than age. PB noted that where the CBRM model forecasts asset replacement the planning process will also review that replacement is based on asset condition.[332]

The AER has reviewed the documentation provided by Energex, including the full application of CBRM. The AER is satisfied this documentation provides a level of detail which supports the need for asset replacement and renewal capex identified by Energex.

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other material, the AER is satisfied that Energex forecast replacement capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

Ergon Energy

The AER notes that Ergon Energy has extensive and well integrated documentation which demonstrates a thorough framework for the management of replacement capex. The key policies and procedures relating to the development of the proposed replacement capex program generally accord with the principles of good asset management and good electricity industry practice.

Ergon Energy, despite claiming to use a condition based approach to asset replacement also applies an age based approach. The AER considers that a condition

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332 PB, *Report – Energex*, October 2009, p. 38.

based approach which takes into account a range of factors (one being asset age) is more likely to result in an efficient outcome. The application of both a condition based and age based asset replacement approach is unlikely to result in prudent and efficient capex.

The AER notes that Ergon Energy was unable to provide sufficient information to satisfy PB as to the basis for its forecast replacement volumes (with the exception of underground cables and joints replacement capex). Given Ergon Energy's inability to substantiate replacement volume forecasts and its use of an age based asset replacement approach rather than a condition based approach, the AER considers that Ergon Energy has not demonstrated that its forecast replacement capex is prudent and efficient.

The AER notes PB's approach to developing a business as usual level of growth which is based on historical expenditures with abnormal under and over spends removed. The replacement capex growth rate in the current regulatory control period has shifted downwards. Therefore the growth rate for the replacement capex for the period from 2001–02 to 2005–06 was applied to the replacement capex in the last year of the current regulatory control period to establish a business as usual forecast. The AER considers that in the absence of sound data for replacement capex volumes and a condition based only asset replacement program, the approach recommended by PB provides a reasonable approach to determining a substitute forecast replacement capex allowance.

The AER requested Ergon Energy model the impact of the AER's decision on replacement capex. Ergon Energy advised that the adjustment to forecast replacement capex is a reduction of $119 million ($2009–10).[333]

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast replacement capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed replacement capex by $119 million[334] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

Reliability capex

The AER notes SPA Consulting Engineers' comments that the distribution networks should be constructed in the most economical manner while also delivering a reliability standard demanded by the community. The AER is required to assess the Qld DNSPs' regulatory proposals to ensure they are prudent and efficient. In conducting its assessment of the Qld DNSPs' regulatory proposals, the AER has made a number of adjustments to Ergon Energy's proposed reliability and quality capex and accepted Energex's proposed reliability capex. The AER considers its draft decision includes an allowance for the minimum reliability capex for the Qld DNSPs and will allow them to continue to develop a reliable network for the benefit of consumers.

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333 Ergon Energy, response to the AER, 17 November 2009, confidential.
334 See table 7.7 for the treatment of the shared cost component of this deduction.

Energex
The AER notes the reliability targets to apply to Energex in the next regulatory control period are more difficult to achieve than those applying in the current regulatory control period as the result of the QCA's final decision on the MSS.[335] The AER also notes that failure to meet the mandatory MSS is a breach of the Electricity Industry Code (EIC) which may result in the QCA issuing warning notices, Code contravention notices or instituting of Supreme Court proceedings.[336]

The AER notes that PB analysed the proposed expenditure in terms of the cost of SAIDI minutes saved. It found that the cost of SAIDI minutes saved is forecast to increase in the next regulatory control period compared to the current regulatory control period.[337] The AER also notes that Energex has proposed a capex program which includes many large scale capital intensive projects such as upgrading and building new feeders, undergrounding poorly performing overhead feeders and the installation of new substations.[338] These types of projects require significant planning and are of a scale that would prevent them being commenced at short notice. The AER considers it reasonable that many of the low cost improvements would have been achieved by Energex in the current regulatory control period and larger projects would be targeted in the next regulatory control period. Given the more onerous MSS targets and the likelihood that many low cost improvements may have already been made, the AER considers that it is reasonable that Energex be allowed an increase in its forecast reliability capex allowance.

The AER has reviewed the documentation provided by Energex, the MSS set by the QCA, the requirements of the EIC and the advice of PB. The AER is satisfied the documentation, existence of licence conditions and the analysis conducted by PB supports the need for the reliability and quality of service enhancement capex identified by Energex. The AER considers that the overall reliability and quality improvement capex program is prudent and efficient.

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other material, the AER is satisfied that Energex forecast reliability capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

Ergon Energy
The AER notes that Ergon Energy's reliability and quality capex is aimed at meeting internally and externally set MSS as specified in the Queensland EIC.[339] The EIC states that a DNSP must use its best endeavours not to exceed the SAIDI and SAIFI limits set out in the EIC.[340]

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335 QCA, *Review of electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010 – Final decision*, April 2009, pp. 2 and 20.
336 Energex, *Regulatory proposal*, July 2009, p. 128.
337 PB, *Report – Energex*, October 2009, p. 45.
338 Energex, *Regulatory proposal*, July 2009, p. 70.
339 Ergon Energy, *Regulatory proposal*, July 2009, p. 209.
340 Queensland Government, Department of Mines and Energy, *Electricity Industry Code*, Fourth edition, effective 4 August 2008, p. 17.

The reliability targets (set by the QCA) that apply to Ergon Energy over the next regulatory control period are progressively more difficult to achieve and it is reasonable that Ergon Energy be provided with an allowance to target reliability and quality improvement.

Ergon Energy has established prudent strategies to identify the worst performing parts of its network and target expenditure on those areas. The AER notes that PB considered Ergon Energy's policies and procedures that relate to the management of reliability and quality improvement are generally consistent with good electricity industry practice.[341] The AER has also reviewed the documentation provided by Ergon Energy in support of its proposed reliability and quality capex and accepts PB's advice that the documentation is consistent with good electricity industry practice.

PB conducted a detailed review of the SCADA acceleration program and concluded that the strategy and program were prudent and efficient. The AER reviewed the documentation and details of the program and notes that benefits will accrue to both Ergon Energy and its customers. The AER accepts PB's advice that the SCADA acceleration program is prudent and efficient.

PB also conducted a detailed review of the feeder improvement program and due to the lack of supporting information, was unable to conclude that the feeder improvement program is efficient. The AER has reviewed the feeder improvement program documentation and accepts PB's advice that there is insufficient information to support the program.

The AER accepts PB's advice that forecast reliability and quality capex be maintained at current period levels with an allowance for the SCADA acceleration program added to it.

The AER requested Ergon Energy model the impact of the AER's decision on reliability and quality capex. Ergon Energy advised that the adjustment to reliability and quality capex is a reduction of $35 million ($2009–10).[342]

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast reliability and quality capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed reliability and quality capex by $35 million[343] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

Security compliance capex (Energex only)

The AER notes Energex stated that the primary purpose of security compliance capex is to meet N–1 security standards and projects within this category address network limitations that breached security of supply standards at the time the forecast capex

[341] PB, *Report – Ergon Energy*, October 2009, p. 58.
[342] Ergon Energy, response to the AER, 17 November 2009, confidential.
[343] See table 7.7 for the treatment of the shared cost component of this deduction.

was developed.[344] The AER notes that Energex considers that its security compliance projects must proceed to ensure compliance with the electricity distribution and servie delivery review (EDSD Review).[345]

The AER notes Energex expects to significantly reduce both the raw and residual load at risk following a fault on its network as a result of its security compliance capex program during the next regulatory control period.[346] Energex does not expect to be fully compliant with its security of supply standards until approximately 2017–18.

The AER notes that the EUAA is concerned that the AER should satisfy itself that the proposed security capex of $1.8 billion is reasonable and responsible. Additionally, Origin Energy stated that it would be useful to understand when Energex will meet its N–1 security obligations. The AER engaged PB to review Energex's proposed capex allowance including its proposed security compliance capex. PB concluded that Energex has adopted a pragmatic approach to developing its standards and the level of risk can be managed through prudent management practices. PB advised that the proposed standards are in accordance with good electricity industry practice and would lead to prudent and efficient expenditure and the AER has accepted PB's advice.

The AER has considered the proposal put forward by Energex and the proposed security standards, which form the basis of the proposed security compliance capex program and concluded that they represent a pragmatic approach to security of supply and results in a level of risk accepted in other jurisdictions in Australia.

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, PB's report and other material, the AER is satisfied that Energex forecast security compliance capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

Other system capex (Ergon Energy only)

The AER has considered PB's detailed review and recommendations on the categories of other system capex as well as the documentation provided by Ergon Energy. The AER's considerations on each category of other system capex are set out below.

Communications

Communications is the largest category of other system capex and relates to the UbiNet project. The AER notes that the QTC undertook a review of the UbiNet business case concluding that the benefits were marginal and an increase in capital costs would make it uneconomical to proceed.[347] QTC also stated that there are strategic considerations and other qualitative factors that better align the likely outcomes achieved from the UbiNet implementation with the strategic direction of

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344 Energex, *Regulatory proposal*, July 2009, p. 200.
345 Queensland Department of Natural Resources, Mines and Energy, *Detailed Report of the Independent Panel, Electricity Distribution and Service Delivery for the 21st Century*, July 2004.
346 Energex, *Regulatory proposal*, July 2009, p. 207.
347 PB, *Report – Ergon Energy*, October 2009, p. 64.

Ergon Energy.[348] Evans and Peck also conducted a review of the business case concluding that the estimated capital costs were in line with a project of UbiNet's size and geographical spread. The AER also notes that PB did not recommend any adjustments to proposed communications capex.

On reviewing the documentation provided and the analysis of PB, the AER accepts PB's advice that the UbiNet project is, at this stage, economically justified. The AER considers that the proposed expenditure is prudent and efficient.

Undergrounding

The majority of undergrounding capex relates to the 'CARE program' which involves the progressive undergrounding of critical high voltage infrastructure in cyclone prone areas. The AER notes PB's conclusion that, despite the declining value of the CARE program, forecast capex was in line with business as usual expenditure (that is, historical expenditure with abnormal under and over spends removed).[349]

The AER notes that while the initial phase targeted high priority customers (such as hospitals and schools), the second phase is aimed at a wider range of customers. Therefore, while the value may be declining, the CARE program is still likely to provide benefits to customers.

The AER has reviewed the information provided by Ergon Energy in support of its proposed undergrounding capex and considers the programs and strategy are likely to provide community and customer benefits. Further, the AER notes that PB did not recommend any adjustments to proposed undergrounding capex, concluding that it is prudent and efficient. The AER has accepted PB's advice and not made adjustments to Ergon Energy's forecast undergrounding capex.

Single wire earth return

Ergon Energy provided the AER with information setting out its assessment of the current state of its SWER network as well as its proposed improvements to the network over the next regulatory control period. The AER considers that based on the information provided, Ergon Energy has developed a plan to improve its SWER network and the proposed SWER capex will assist it to achieve this aim. The AER considers Ergon Energy's proposed SWER capex to be prudent. Further, the AER notes that based on its high level review, PB considered the proposed capex to be prudent and efficient and did not recommend any adjustments to proposed SWER capex. The AER accepts PB's advice regarding SWER capex.

Protection

The majority of capex involves retrofitting autoreclose protection and sensitive earth fault (SEF) protection on existing feeders. The AER notes that Ergon Energy has developed strategies for identifying problem feeders and aligns the proposed programs with other protection programs to optimise efficiency. Further, the AER notes that PB has not recommended any changes to proposed protection capex and the AER has accepted that advice.

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348 QTC, Letter to Ergon Energy: UbiNet project – Financial model and high level business case review, confidential, 14 May 2008, p. 5.

349 PB, *Report – Ergon Energy*, October 2009, pp. 66.

Other programs

The other programs category includes a number of smaller projects involving substation security, retro fitting low voltage fuses, substation bunding works, improving the reliability of substation alternating current supplies and fitting low voltage spreaders to lines to prevent conductor clashing. PB conducted a high level review of proposed other programs capex and did not recommend any adjustments, concluding that it is prudent and efficient. The AER has accepted PB's advice and not made any adjustments to this category of capex.

Summary

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's regulatory proposal, PB's report and other material, the AER is satisfied that Ergon Energy's forecast other system capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

Non-system capex

Energex

The AER reviewed Energex's non–system capex proposal, taking into account additional information provided in support of the regulatory proposal and the advice of PB.

The AER reviewed Energex's regulatory proposal and the policies and procedures underpinning the proposed expenditures for tools and equipment, motor vehicles and end–use computing assets. The AER notes that expenditures in these categories are either below or consistent with historical levels of expenditure.[350] The AER considers that the proposed expenditures for tools and equipment, motor vehicles and end–use computing assets are prudent and efficient.

In assessing the proposed land and buildings capex, the AER notes that business case documentation or other supporting documentation for the high value individual property projects proposed by Energex was not available. This included documentation for expenditure proposed for the first year of the regulatory control period, as Energex intended to develop such documentation closer to project realisation.[351]

The AER considers that the requirement to replace the logistics and warehousing facility in the next regulatory control period has not been sufficiently established by Energex, noting that the site will become untenable only in the medium to long term.[352] The AER considers that given the subjective nature of the risk assessment and in the absence of a full site options analysis, the process employed by Energex in relation to the proposed replacement of the warehousing site has not been demonstrated to be prudent considering the large expenditures involved. The AER considers that an allowance for upgrading the warehousing site over a ten year period

[350] Energex, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, confidential.
[351] PB, *Report – Energex*, October 2009, p. 67.
[352] Maunsell, *Distribution Facility Opportunities and Constraints Analysis*, May 2008, p. 47, confidential.

is more representative of a prudent and efficient level of expenditure in the next regulatory control period.

On the basis of its review and advice from PB, the AER considers that the major building project expenditures proposed by Energex, which are not supported by business case documentation, have not been demonstrated to be prudent and efficient and should be removed from the capex proposal. The AER considers that Energex's land and buildings capex should align with Energex's business as usual costs (that is, excluding the proposed new major building projects) plus an allowance to refurbish the warehousing facility. The AER requested Energex model the impact of the AER's decision on non–system land and buildings capex. Energex advised that the adjustment to forecast non–system capex is a reduction of $158 million.[353]

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's proposed non–system capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed non–system capex by $158 million[354] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

Ergon Energy

The AER has reviewed Ergon Energy's non–system capex proposal, taking into account additional information provided in support of the regulatory proposal and the advice of PB.

Having reviewed Ergon Energy's regulatory proposal and the policies and procedures underpinning these expenditures, the AER considers that the proposed expenditures for plant and tools and motor vehicles, which are either below or consistent with historical expenditures in these categories, represent the efficient costs of a prudent operator in Ergon Energy's circumstances.

In relation to Ergon Energy's proposed ICT systems capex, the AER notes that Ergon Energy was unable to provide business case documents in support of the Change Program and associated overheads proposed. The AER is not satisfied on the basis of the information provided by Ergon Energy that the costs associated with the Change Program have been justified as prudent and efficient expenditures. The AER considers that costs associated with the Change Program should be excluded from Ergon Energy's proposed ICT systems capex. The AER requested Ergon Energy model the impact of the AER's decision on ICT systems capex. Ergon Energy advised that the adjustment to forecast ICT systems capex is a reduction of $65 million ($2009–10).[355]

The AER notes that Ergon Energy's proposed capex for non–system property (comprising expenditure on buildings, land, easements, office equipment and furniture) amounts to $387 million during the next regulatory control period, a

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[353] Energex, response to the AER, 11 November 2009, confidential.
[354] See table 7.6 for the treatment of the indirect cost component of this deduction.
[355] Ergon Energy, response to the AER, 17 November 2009, confidential.

significant increase of 74 per cent from the current regulatory control period.[356] The AER received a submission from the EUAA noting the very significant expansion of expenditure by Ergon Energy on corporate property and requesting that the AER investigate this carefully to determine its purpose, relevance and benefit.[357]

The AER notes that Ergon Energy was unable to provide business case documentation for the high value property projects proposed for Townsville, Cairns, Rockhampton, Toowoomba, Maryborough and the data centre, including in relation to expenditure proposed for the first year of the regulatory control period.[358]

The AER considers that Ergon Energy's proposal has not adequately demonstrated the prudence and efficiency of the program of proposed building works, for example through a clear exposition of the consideration of options, prioritisation of projects or cost–benefit analysis underpinning the proposed program. The AER therefore considers that the major building project expenditures identified above as not supported by business case documentation have not been demonstrated to be prudent and efficient and should be removed from the capex proposal. The AER requested Ergon Energy model the impact of the AER's decision on property capex. Ergon Energy advised that the adjustment to forecast property capex is a reduction of $188 million ($2009–10).[359]

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's proposed non–system capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed non–system capex by $253 million[360] results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

7.8.4 Overheads

7.8.4.1 Qld DNSP regulatory proposals

The capex proposed by Energex and Ergon Energy for the next regulatory control period includes overhead costs that are required to run the DNSPs' business but which are not directly attributed to a specific activity or service.[361] As a result, they are allocated across services consistent with the AER approved cost allocation methods for each business.

Overhead costs for the Qld DNSPs include, but are not limited to, the following:

- corporate support costs including the office of the chief executive, corporate governance and finance and strategic services

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356 Ergon Energy, *Regulatory proposal*, July 2009, RIN template 2.2.1.
357 EUAA, *Submission to the AER*, August 2009, p. 21.
358 PB, *Report – Ergon Energy*, October 2009 p. 85.
359 Ergon Energy, response to the AER, 17 November 2009, confidential.
360 See table 7.7 for the treatment of the shared cost component of this deduction.
361 Overheads are referred to as indirect costs by Energex and shared costs by Ergon Energy.

- employee and shared services
- ICT
- customer services.

The Qld DNSPs indicated that large proportions of their overheads are related to the provision of ICT services provided by SPARQ, which is jointly owned by the Qld DNSPs and provides ICT services to both businesses.[362]

The Qld DNSPs commissioned KPMG to perform a review of the prudency and efficiency of the ICT services delivered by SPARQ. KPMG found SPARQ to be an efficient ICT service provider, outperforming its peers in many of the efficiency indicators, and that its expenditure forecasts are reasonable.[363]

7.8.4.2 Consultant review

PB indicated that it assessed the prudence and efficiency of overheads costs as part of its review of capex and opex at an expenditure category level for the Qld DNSPs.

For both businesses, PB identified step changes in expenditure relative to current levels for ICT services. In order to establish the underlying prudence and efficiency of the proposed forecasts of ICT expenditure, PB reviewed the ICT capex proposed by each DNSP and SPARQ (as it relates to each DNSP) and considered these as if they were one proposal for each business.[364] In assessing the proposed ICT expenditure for the Qld DNSPs, PB focused on proposed new capabilities, having regard to:[365]

- strategic alignment of individual ICT projects or programs with Energex's broader strategies, policies or other objectives and drivers
- project need, materiality and timing
- options analysis, including explanation as to why the preferred option is the most efficient
- financial and/or economic appraisal that demonstrates value for money, cost savings and/or net benefits of the project or program
- procurement and delivery strategy.

For both DNSPs, PB noted that the majority of ICT proposed expenditure was for 'steady state', or business as usual, expenditure. PB found that the majority of projects

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362 Energex, *Regulatory proposal*, July 2009, p. 189; and Ergon Energy, *Regulatory proposal*, July 2009, p. 344.

363 Energex, *Regulatory proposal*, July 2009, p. 189; and Ergon Energy, *Regulatory proposal*, July 2009, p. 347.

364 PB, *Report - Energex*, October 2009, p. 55; and PB, Report – *Ergon Energy*, October 2009, p. 72.

365 PB, *Report – Energex*, October 2009, p. 60; and PB, *Report – Ergon Energy*, October 2009, pp. 76–77.

had a clear description of need and purpose, but that expenditures were not supported by analysis that demonstrated prudence or efficiency.[366]

One exception to this for Energex was $15.5 million ($2009–10) of expenditure proposed for the 'DMS Stage 2' project, for which PB found the business case to be comprehensive.[367] One exception for Ergon Energy was $4.9 million ($2009–10) of expenditure proposed for reconfiguration of the data centre, for which PB found a more robust business case than other proposed projects.[368]

To calculate the reductions in the service charges to the Qld DNSPs associated with SPARQ capex, PB used the 2008-09 SPARQ service charges to each business as the base year cost and assumed the increases in the ICT indirect costs during the next regulatory control period are predominately driven by SPARQ capex. PB then applied reductions to the increases in the SPARQ service charges that are proportional to the reductions recommended for the SPARQ ICT capex for each DNSP.

Based on this approach, PB recommended reductions in ICT indirect costs of $9.5 million ($2009–10) for Energex and $20.4 million ($2009–10) for Ergon Energy.[369] This results in capex reductions of $7.3 million for Energex and $15.7 million for Ergon Energy.

7.8.4.3 AER considerations

The AER notes that PB has assessed the prudence and efficiency of overheads as part of its review of capex (and opex) at an expenditure category level and found that, with the exception of ICT costs, there were no unaccounted for step changes in expenditure.

The AER notes that the bulk of Energex's and Ergon Energy's ICT services are delivered by SPARQ and covered by service charges to each DNSP. The AER considers that PB's review of SPARQ's ICT capex is an appropriate method of determining the prudence and efficiency of SPARQ's service charges to Energex and Ergon Energy.

The AER notes that the majority of ICT expenditure proposed by SPARQ is for a business as usual level of capability. The AER considers that PB's focus on expenditure for new capabilities is appropriate. This is because the efficiency and prudency of business as usual expenditure is likely to have been better established compared to expenditure for new capabilities.

The AER notes that PB has conducted a detailed review of the proposed new capabilities, having had regard to a range of considerations, including project need and efficiency, options analysis and delivery strategy. As a result, the AER accepts PB's findings that expenditure proposed for Energex's DMS Stage 2 project and Ergon Energy's data centre reconfiguration are well justified.

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366 PB, *Report – Energex*, October 2009, p. 61; and PB, *Report – Ergon Energy*, October 2009, pp. 80–81.
367 PB, *Report – Energex*, October 2009, p. 61.
368 PB, *Report – Ergon Energy*, October 2009, p. 77.
369 PB, *Report – Energex*, October 2009, p. xvi; and PB, *Report – Ergon Energy*, October 2009, p. xvi.

Regarding other projects for new capability, the AER notes PB's finding for both DNSPs that expenditure is not supported by analysis that demonstrated prudence or efficiency. For these reasons, the AER accepts PB's conclusion that Energex and Ergon Energy have not demonstrated that the proposed ICT expenditure by SPARQ for new capability projects (except for DMS Stage 2 for Energex and data centre reconfiguration for Ergon Energy) is prudent or efficient.

As discussed in appendix J to this draft decision, the AER also rejects expenditure proposed by Ergon Energy for sponsorship and other community engagement activities.

For the reasons discussed, and as a result of the AER's consideration of Energex's and Ergon Energy's regulatory proposals and PB's reports, the AER is not satisfied that the forecasts of overhead costs for Energex and Ergon Energy reasonably reflect the capex criteria, including the capex objectives.

The AER considers that reducing the proposed allocation of overhead costs to capex by $7 million for Energex and $39 million for Ergon Energy results in expenditures that reasonably reflect the capex criteria, including the capex objectives, and are the minimum adjustments necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

7.8.5 Cost accumulation

7.8.5.1 Qld DNSP regulatory proposals

Energex and Ergon Energy engaged consultants to provide assessments of forecast movements in the cost of input components in their capex proposals.

Energex engaged KPMG to develop escalation rates for the cost of labour, materials and contractors.[370] KPMG recommended annual escalation rates for nominal labour, materials and contractor costs over the next regulatory period, based on a combination of three statistical techniques and anecdotal evidence.[371] In an updated report on materials, KPMG cited qualitative evidence indicating significant variation in the escalation rates in 2008 and 2009 and on that basis recommended a real escalation rate for materials of zero per cent and that this be reviewed closer to the start of the next regulatory control period.[372]

Ergon Energy engaged SKM to develop cost escalators to apply to its capex forecasts. SKM identified the key factors influencing Ergon Energy's capex costs, such as labour, construction costs, copper and aluminium, and their contributions to the total cost of items of plant, equipment and materials that comprise network assets.[373] SKM then mapped changes in the cost of individual items of plant, equipment and materials to changes in the cost of network infrastructure projects and asset classes through the application of established project 'building blocks'. SKM also developed escalation

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370 Energex, *Regulatory proposal*, July 2009, p. 176.

371 Energex, *Regulatory proposal*, July 2009, appendix 12.6: KPMG Final report on escalation rates for labour, materials and contractors, p. 1.

372 Energex, *Regulatory proposal*, July 2009, appendix 12.7, KPMG, Final report on escalation rates for other asset categories and materials, p. 29.

373 Ergon Energy, *Regulatory proposal*, July 2009, p. 337.

rates for Ergon Energy's non–network capex, including land and easements, IT systems, motor vehicles and buildings.[374] SKM reviewed the application of its cost escalators by Ergon Energy in its internal models and warranted that Ergon Energy had applied the escalators in the manner SKM intended.[375]

7.8.5.2 Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of Energex's and Ergon Energy's expenditure proposals. PB was not required to assess forecast rates of growth in input costs (this exercise has been undertaken by the AER and is described in detail in appendix H). However, as part of its review, PB was required to ensure that forecast changes in input costs have been appropriately reflected in the cost escalation calculations performed by Energex and Ergon Energy in forecasting capex.

In relation to Energex, PB was provided with a model built by Energex to demonstrate the application of escalators within its cost estimating systems to the relevant expenditure type.[376] PB reviewed Energex's escalator model and found that:[377]

- the cost escalators are applied to the correct expenditure type categories and therefore the cost escalators are inherently weighted correctly according to the value of each expenditure type

- the expenditures at the asset category level sum to amounts that equal the total proposed expenditure.

Based on these findings, PB concluded that it was satisfied with the treatment of escalators within the Energex model and confident that the model represents the impact of escalation within Energex's enterprise systems.[378]

In relation to Ergon Energy, PB reviewed the analysis that SKM undertook for Ergon Energy in relation to cost escalation for capex, noting that it results in escalation indices that are directly applicable to Ergon Energy's breakdown of forecast capex into asset classes. PB considered this to be a detailed approach that is suitable for application to Ergon Energy's forecast capex.[379]

In order to form a view about the appropriateness of the weightings used by SKM to prepare the asset class escalators for capex, PB compared them to its own high-level estimates of typical weightings and on this basis, concluded that the results of applying the SKM weightings as used by Ergon Energy are considered efficient.[380]

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374 Ergon Energy, *Regulatory proposal*, July 2009, p. 338.
375 Ergon Energy, *Regulatory proposal*, July 2009, p. 339.
376 PB, *Report – Energex*, October 2009, p. 11.
377 PB, *Report – Energex*, October 2009, p. 11.
378 PB, *Report – Energex*, October 2009, p. 11.
379 PB, *Report – Ergon Energy*, October 2009, p. 12.
380 PB, *Report – Ergon Energy*, October 2009, p. 12.

PB noted that Ergon Energy applied the capex asset class escalators calculated by SKM in a spreadsheet model for forecasting capex. PB identified two problems with the workings of the model:[381]

- the calculation of cumulative nominal escalators in step 2 includes the cumulative effect of CPI but not of the escalators themselves
- the set of CPI values used to inflate 2007–08 real values to nominal in step 2 is different from the set used to deflate back to 2009–10 real values in step 5.

PB calculated that correction of these issues results in a downward revision to forecast capex of $270 million ($2009–10) over the next regulatory control period.[382]

7.8.5.3 AER considerations

Energex

The AER's detailed consideration and conclusions on Energex's input cost escalators, and the methodologies underpinning those escalators, are set out at appendix H to this draft decision. The AER has not accepted the methodologies used to develop Energex's real cost escalators.

The AER does not consider Energex's escalation rates for labour costs are acceptable because, amongst other things, constant wage growth forecasts do not accurately represent the volatility of the current market and the forecasts do not reflect the most recently available data.

The AER does not consider Energex's escalation rates for materials costs are acceptable because they do not reflect actual and forecast changes in materials costs, most notably significant decreases in materials costs in 2008–09 and 2009–10.

Regarding the application of cost escalators by Energex in calculating its capex forecasts, the AER has considered PB's review of Energex's cost escalator model and is satisfied with PB's findings in relation to Energex's application of cost escalators from 2009–10 to 2014–15.

The AER requested Energex to model the impacts of the AER's decisions in relation to cost escalation. Energex advised that the adjustment to forecast capex is a reduction of $372 million ($2009–10).[383]

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's cost escalation reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed capex by $372 million ($2009–10) results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for capex to comply with the NER. In coming to this view the AER has had regard to the capex factors.

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381 PB, *Report – Ergon Energy,* October 2009, p. 12.
382 PB, *Report – Ergon Energy,* October 2009, p. 12.
383 Energex, response to the AER, 11 November 2009, confidential.

Ergon Energy

The AER's detailed consideration and conclusions on Ergon Energy's input cost escalators, and the methodologies underpinning those escalators, are set out at appendix H to this draft decision. The AER has not accepted the methodologies used to develop Ergon Energy's real cost escalators.

The AER does not consider Ergon Energy's application of a single escalation rate to internal and contract labour costs is appropriate because, amongst other things, it diminishes the commercial incentive for Ergon Energy to negotiate competitive wage outcomes and it does not differentiate between specialist and general labour resources.

The AER does not consider Ergon Energy's escalation rates for materials costs are acceptable because they do not reflect the most up to date market–based forecasts of future materials costs.

Regarding the application of cost escalators by Ergon Energy in calculating its capex forecasts, the AER notes PB's finding that the analysis that SKM undertook for Ergon Energy results in escalation indices that are directly applicable to Ergon Energy's breakdown of forecast capex into asset classes. The AER considers that SKM's approach appears to be very detailed and therefore likely to accurately reflect real cost changes in assets over the next regulatory control period. This is supported by PB's conclusion that SKM's approach is suitable for application to Ergon Energy's forecast capex.

The AER is satisfied that PB's use of its own high-level estimates of typical weightings for capex asset class escalators provides a sound basis for review and therefore accepts PB's conclusion that the weightings applied by Ergon Energy are efficient.

The AER notes PB findings in relation to the application of capex cost escalators by Ergon Energy in its capex modelling. The AER has reviewed Ergon Energy's capex model and confirmed the errors found by PB.

The AER requested Ergon Energy model the impact of the AER's draft decision on capex cost escalation on its forecast capex. Ergon Energy advised that the adjustment to forecast capex is $82 million ($2009–10).[384]

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's application of real cost escalators reasonably reflects the capex criteria, including the capex objectives. The AER considers that increasing Ergon Energy's proposed capex by $82 million results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for capex to comply with the NER. In coming to this view the AER has had regard to the capex factors.

384 Ergon Energy, response to the AER, 17 November 2009, confidential.

7.8.6 Deliverability of the forecast capex program

7.8.6.1 Qld DNSP regulatory proposals

As mentioned in section 7.5, Energex and Ergon Energy proposed a total forecast capex requirement of $6466 million ($2009–10) and $6033 million ($2009–10) respectively for the next regulatory control period. The Qld DNSPs' forecast capex for the next regulatory control period is approximately 50 per cent (in real terms) higher than the level expected during the current regulatory control period.

Energex stated that the delivery of its works program in the next regulatory control period would depend heavily on the continuation of its current multi–faceted approach, which Energex intends to consolidate and refine through the following:[385]

- a 'People Strategy for 2010–15' that is aimed at retaining and developing staff through a range of specific programs, including for tradesperson recruitment, apprentices, para-professional traineeships, graduates and technical skills
- a revised contracting strategy to build on the strengths of the current arrangements through consolidation of the supplier base and resultant long term efficiencies
- the inclusion of a pre–qualification step in its procurement process to streamline the engagement of reliable resource providers.

Ergon Energy stated it was confident of delivering its proposed works program because it has achieved this level of growth previously in a tight labour market and is therefore confident that it can be achieved again.[386] Ergon Energy indicated a range of activities intended to improve deliverability including recently implementing a range of organisational improvements designed to manage future workload growth and extending its alternative provider model to include commercial, industrial and large customer initiated capital works.[387]

7.8.6.2 Consultant review

PB reviewed Energex and Ergon Energy's ability to deliver their proposed works program during the next regulatory control period respectively.[388]

PB found that the contracting strategies Energex has implemented indicate that it can develop the capability to deliver the proposed works programs. PB considered that a move by Energex to prequalification schemes will result in additional contracting efficiencies and that its material procurement practices should ensure that materials are available when required. PB also considered that Energex's ability to procure additional resources is strengthened in light of the recent global financial crisis and

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385 Energex, *Regulatory proposal*, July 2009, pp. 210–213.
386 Ergon Energy, *Regulatory proposal*, July 2009, p. 350.
387 Ergon Energy, *Regulatory proposal*, July 2009, pp. 350–351.
388 PB, *Report – Energex, October 2009*, pp. 122–126; and PB, *Report – Ergon Energy*, October 2009, pp. 149–154.

the subsequent increased availability of resources in comparison with the current regulatory control period.[389]

PB found that Ergon Energy has undertaken only a high-level and cursory review of its capability to deliver the forecast program of works and that this introduced an element of risk to delivery of the program.[390] However, PB also considered that this risk was not likely to prevent Ergon Energy from delivering its works program, on the basis that Ergon Energy:[391]

- has demonstrated it can ramp up its program of works significantly, as shown in 2006–07 and 2008–09
- has a number of strategies in place to engage and retain its internal ageing workforce, and to attract new employees
- has proposed capex that includes a significant component which is well suited to outsourcing
- has well established technical standards for undertaking the design and construction of works, as well as to maintain its assets
- has long standing relationships with third party contractors to supply both labour and materials
- undertakes a reasonable amount of non-regulated work and that these resources can be used to balance regulated work needs
- will benefit from a reasonable level of competition from external contractors for a significant portion of the increases in the program of works.

PB concluded that the Qld DNSPs should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.[392]

7.8.6.3 AER considerations

Energex

The AER notes that Energex's forecast capex program represents a significant increase compared to the level of investment undertaken in the current regulatory control period. However, the AER considers that Energex appears to be well prepared for delivering this increased level of works.

The AER notes PB's findings that Energex's overall approach to planning and implementing its capex program is consistent with good industry practice. The AER considers this will continue to underpin Energex's ability to deliver an increasing level of works. Further, the AER considers that the range of enhancements being made by Energex in the areas of contracting and procurement should improve Energex's ability to deliver its future works program.

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389 PB, *Report – Energex*, October 2009, pp. 125–126.
390 PB, *Report – Ergon Energy*, October 2009, p. 155.
391 PB, *Report – Ergon Energy*, October 2009, pp. 155–156.
392 PB, *Report – Energex*, October 2009, p. 126; and PB, *Report – Ergon Energy*, October 2009, p. 154.

The AER notes PB's conclusions that Energex should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.

Having considered Energex's forecast capex program and proposed delivery strategies, and the advice of PB, the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability.

The AER is also satisfied that the deliverability of Energex's forecast capex is consistent with the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

The AER notes that the reductions it has proposed for Energex's forecast capex in this draft decision provides further confidence that Energex will be able to deliver its program of works.

Ergon Energy

The AER is concerned by PB's finding that Ergon Energy has undertaken only a high-level and cursory review of its capability to deliver the forecast program of works, particularly given that it represents a significant increase compared to the level of investment undertaken in the current regulatory control period.

However, the AER considers that there are numerous reasons that more than off-set this concern, which together suggest that Ergon Energy is likely to be able to deliver its proposed capex program. In particular, the AER considers that Ergon Energy has demonstrated its ability to significantly expand its work program during the current regulatory control period. The AER also notes PB's findings in relation to the aspects of Ergon Energy's proposed capex that make it amenable to outsourcing, and Ergon Energy's well-established materials procurement practices. The AER also notes that Ergon Energy has a number of strategies in place to engage and retain its internal ageing workforce, and to attract new employees.

The AER notes PB's conclusions that Ergon Energy should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.

Having considered Ergon Energy's forecast capex program and proposed delivery strategies, and the advice of PB, the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability.

The AER is also satisfied that the deliverability of Ergon Energy's forecast capex is consistent with the capex objectives generally, and in so far as this aspect is concerned is satisfied it reasonably reflects the capex criteria.

The AER further notes that the reductions it has proposed for Ergon Energy's forecast capex and opex elsewhere in this draft decision provides further confidence that Ergon Energy will be able to deliver its program of works.

7.9 AER conclusion

For the reasons summarised in this chapter and detailed in appendices F and G, the AER is not satisfied that the proposed forecast capex allowances of Energex and Ergon Energy reasonably reflect the capex criteria, under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER.

As the AER is not satisfied that the total capex allowances proposed by Energex and Ergon Energy reasonably reflect the capex criteria, under clause 6.5.7(d) of the NER the AER must not accept them in its distribution determination. Under clause 6.12.1(3)(ii) of the NER, the AER is therefore required to provide an estimate of the capex for Energex and Ergon Energy over the next regulatory control period which it is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

The AER's conclusions, the adjustments it requires and the resulting estimates of the forecast capex allowance it is satisfied reasonably reflects the capex criteria in the next regulatory control period for Energex and Ergon Energy are summarised below.

7.9.1 Energex

Following its review of Energex's capex proposal the AER has made the following adjustments:

- $289 million reduction to growth capex to reflect a realistic expectation of demand
- $158 million reduction to non–system capex to exclude unsupported expenditure on major building projects
- $7 million reduction in indirect costs associated with the ICT services that do not reasonably reflect the capex criteria, including the capex objectives
- $372 million reduction to total capex, applied across all components of forecast capex, to account for errors in the application of input cost escalators.

Following the adjustments outlined above, and as detailed in table 7.6, the AER is satisfied an estimate of $5718 million for Energex's forecast capex reasonably reflects the capex criteria, taking into account the capex factors. The AER considers this reduction is the minimum adjustment necessary to ensure Energex's capex forecast meets the capex criteria.

Table 7.6: AER conclusion on Energex's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0
Adjustment to growth capex	–37.3	–43.8	–60.5	–66.9	–80.0	–288.6
Adjustment to non–system capex	–105.0	–32.7	–20.6	0.0	0.0	–158.3
Adjustment to indirect costs	–0.5	–1.7	–1.6	–1.3	–1.7	–6.8
Re-inclusion of indirect costs removed in the adjustments to growth and non–system capex	19.7	14.3	15.7	12.8	15.1	77.7
Adjustment to cost escalators	–51.6	–61.2	–75.6	–85.1	–98.2	–371.7
AER capex allowance	1064.8	1144.6	1159.3	1151.9	1197.7	5718.3

Notes: Totals may not add due to rounding.
The indirect costs included in adjustments to growth and non–system capex are not to be removed from Energex's capex allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Energex's indirect costs, as discussed in section 7.8.4.

7.9.2 Ergon Energy

Following its review of Ergon Energy's capex proposal the AER has made the following adjustments:

- $844 million reduction to growth capex to reflect a realistic expectation of demand and a revised approach to forecasting customer initiated capital works expenditure
- $119 million reduction to asset replacement capex to reflect a business as usual approach to forecasting expenditure in this category
- $35 million reduction to reliability and quality improvement capex to exclude expenditure associated with the feeder improvement program and reflect a revised level of expenditure based on outcomes in the current regulatory control period plus additional expenditure for the SCADA acceleration program
- $39 million reduction in shared costs associated with the ICT services, sponsorship and community engagement that do not reasonably reflect the capex criteria, including the capex objectives
- $253 million reduction to non–system capex to exclude ICT systems expenditure associated with the Change Program and unsupported expenditure on major building projects.
- $82 million increase to total capex, applied across all components of forecast capex, to account for errors in the application of input cost escalators.

Following the adjustments outlined above, and as detailed in table 7.7, the AER is satisfied an estimate of $5013 million for Ergon Energy's forecast capex reasonably reflects the capex criteria, taking into account the capex factors. The AER considers this reduction is the minimum adjustment necessary to ensure Ergon Energy's capex forecast meets the capex criteria.

Table 7.7: AER conclusion on Ergon Energy's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9
Adjustment to growth capex	–155.1	–179.5	–140.9	–168.2	–200.5	–844.2
Adjustment to asset replacement capex	–9.9	–19.4	–30.9	–30.0	–28.6	–118.8
Adjustment to reliability and quality improvement capex	–2.6	–4.5	–7.1	–9.8	–11.4	–35.3
Adjustment to non–system capex	–95.6	–115.7	–50.6	1.7	6.6	–253.5
Adjustment to shared costs	–2.2	–5.9	–9.2	–9.8	–11.5	–38.6
Re-inclusion of shared costs removed in the adjustments to growth, asset replacement, reliability and non–system capex[a]	40.6	48.3	36.0	30.6	32.6	188.1
Adjustment to cost escalators	–16.2	2.0	22.2	37.6	36.5	82.1
AER capex allowance	845.4	925.2	996.8	1080.0	1165.3	5012.8

Notes: Totals may not add due to rounding.

(a) The shared costs included in deductions to growth, asset replacement, reliability and non–system capex are not to be removed from Ergon Energy's capex allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Ergon Energy's shared costs, as discussed in section 7.8.4.

7.10 AER draft decision

In accordance with clause 6.12.1(3)(ii) of the NER the AER does not accept Energex's forecast capex for the next regulatory control period. The AER is not satisfied that Energex's forecast capex, taking into account the capex factors, reasonably reflects the capex criteria in clause 6.5.7 of the NER. The AER's reasons for this decision are set out in section 7.8 of this draft decision.

The AER's estimate of the total capex required by Energex in the next regulatory period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.6 of this draft decision.

In accordance with clause 6.12.1(3)(ii) of the NER the AER does not accept Ergon Energy's forecast capex for the next regulatory control period. The AER is not satisfied that Ergon Energy's forecast capex, taking into account the capex factors, reasonably reflects the capex criteria in clause 6.5.7 of the NER. The AER's reasons for this decision are set out in section 7.8 of this draft decision.

The AER's estimate of the total capex required by Ergon Energy in the next regulatory period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.7 of this draft decision.

8 Forecast operating expenditure

8.1 Introduction

This chapter sets out the Qld DNSPs' forecast opex proposals, submissions from interested parties, a summary of the AER's consultant review and the AER's conclusion on the Qld DNSPs' opex allowances relating to standard control services for the next regulatory control period.

8.2 Regulatory requirements

Under clause 6.12.1(4) of the NER, the AER must make a decision to accept or not accept the forecast opex included in a building block proposal. If the AER does not accept the proposal it must form its own estimate in accordance with the opex objectives and the opex criteria and factors outlined in clause 6.5.6 of the NER.

8.2.1 Opex objectives

Clause 6.5.6(a) of the NER provides that a DNSP must include the total forecast opex for the regulatory control period in order to achieve the following opex objectives:

(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;

(4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

8.2.2 Opex criteria and factors

Clause 6.5.6(c) of the NER provides that the AER must accept the opex forecast included in a building block proposal if it is satisfied that the total of the forecast opex for the regulatory control period reasonably reflects:

(1) the efficient costs of achieving the opex objectives; and

(2) the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In making this assessment the AER must have regard to the following opex factors contained in clause 6.5.6(e) of the NER:

(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.

Clause 6.5.6(d) of the NER states that, if the AER is not satisfied that a DNSP's forecast opex reasonably reflects the opex criteria, then the AER must not accept the forecast opex in a building block proposal. If the AER does not accept the total forecast opex proposed by a DNSP, clause 6.12.1(4)(ii) of the NER requires the AER to include in its draft decision:

> …an estimate of the total of the DNSP's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

8.3 AER approach to assessment

In determining whether the opex forecast included in the Qld DNSPs' regulatory proposals reasonably reflect the requirements of the NER, the AER has examined whether:

- the Qld DNSPs' governance frameworks, asset maintenance strategies and systems, operating procedures and practices are likely to result in forecast expenditures which are consistent with the opex objectives
- the assumptions used to develop the opex proposal, including unit cost estimates, scale escalation assumptions, real costs escalators, forecasting methodologies and modelling approaches, are robust and likely to produce opex forecasts which are prudent and efficient and reflect a realistic expectation of cost inputs required to meet the opex objectives
- the projects and programs that form part of the opex forecast generally reflect the opex criteria, including with respect to their scope, timing, and costs

- the proposed opex forecasts are commensurate with what a prudent business in the circumstances of the Qld DNSPs would require to achieve the opex objectives.

Overall these considerations are intended to assist the AER to determine whether it is satisfied that the forecast opex reasonably reflects the opex criteria set out at clause 6.5.6(c) of the NER.

The nature of electricity distribution, characterised by large numbers of projects and ongoing programs, has influenced the AER's approach to reviewing the Qld DNSPs' proposals. Specifically:

- while a range of projects and opex programs were reviewed by the AER and PB, the AER's overall assessment has placed less reliance on the review of individual expenditure programs and project reviews

- the AER has reviewed the policies, procedures and underlying assumptions, and how these have been applied by the Qld DNSPs, historically, and in developing the forecasts

- with assistance from its consultant, the AER has considered more general factors (for example, trends in asset age, faults etc) and methods (for example, expenditure modelling) in examining proposed expenditures

- where appropriate, the AER and its consultants have examined departures from identified trends in historical expenditure and efficient base year expenditures

- the AER has compared and contrasted the forecast changes in generic input costs with those proposed by the Qld DNSPs.

8.4 Current period opex outcomes

This section summarises the expenditure outcomes of the Qld DNSPs with respect to the opex allowances set by the QCA, to identify any cost drivers having effect during the current regulatory control period that should be considered when assessing the forecast opex proposals for the next regulatory control period.

Tables 8.1 and 8.2 show opex outcomes for the current regulatory control period for the Qld DSNPs. The actual and proposed opex allowances of Energex and Ergon Energy are shown in figures 8.1 and 8.2.

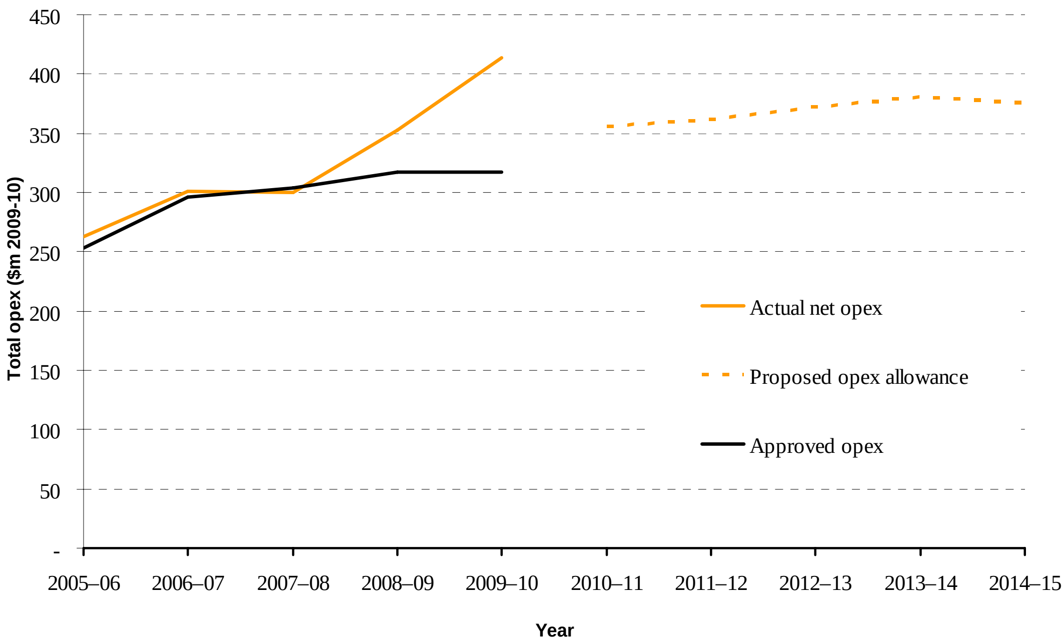
Table 8.1: Energex historical opex spend ($m, 2009–10)

	2005–06	2006–07	2007–08	2008–09	2009–10	Total
Actual opex	262.7	300.7	300.1	352.4	413.3	1629.2
QCA allowance	253.5	296.3	304.2	317.8	317.4	1489.3
QCA approved pass throughs	0	0	22.8	18.9	18.3	60.0
Over spend	9.2	4.4	–4.1	34.6	95.9	139.9
Over spend (%)	3.5	1.5	–1.3	9.3	22.2	9.4

Source: Energex, *Regulatory proposal*, July 2009, p. 120. Adjusted for inflation in accordance with the AER's methodology.

Note: QCA allowance excludes QCA approved cost pass throughs.

Figure 8.1 Energex actual and allowed opex ($m, 2009–10)



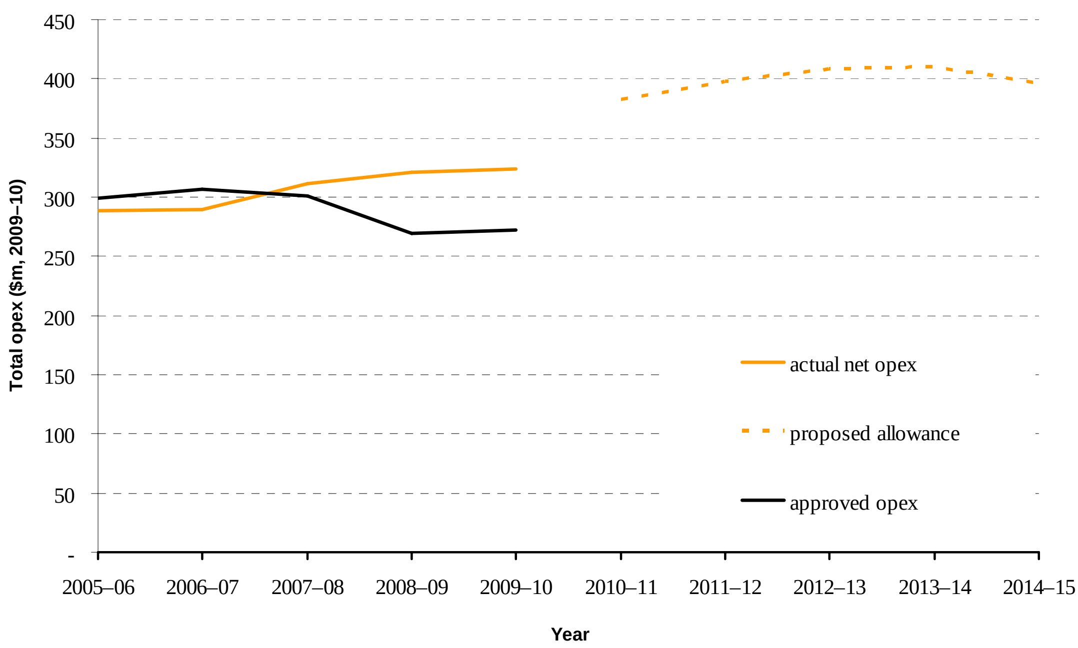
Source: Energex, *Regulatory proposal*, July 2009, p.120 and RIN proforma 2.2.2 and AER analysis.

Table 8.2: Ergon Energy historical opex spend ($m, 2009–10)

	2005–06	2006–07	2007–08	2008–09	2009–10	Total
Actual opex	288.1	289.8	311.8	320.7	324.0	1534.3
QCA allowance	299.3	306.3	309.3	269.4	271.9	1456.2
QCA approved pass throughs	0	0	0	8.0	0	8.0
Over spend	–11.2	–16.5	2.5	51.3	52.1	78.1
Over spend (%)	–3.9	–5.7	0.8	16.0	16.1	5.1

Source: Ergon Energy, *Regulatory proposal*, July 2009, pp. 259–260 and RIN proforma 2.2.2.
Note: QCA allowance excludes QCA approved cost pass throughs.

Figure 8.2 Ergon Energy actual and allowed opex ($m, 2009–10)



Source: Ergon Energy, *Regulatory proposal*, July 2009, pp. 259–60 and RIN proforma 2.2.2; and AER analysis.

8.4.1 Energex

Energex is expected to overspend its regulated opex allowance by approximately $140 million ($2009–10) or 9 per cent of the opex allowance approved by the QCA for the current regulatory control period. Energex submitted that its expected overspend has been driven by:[393]

- higher than expected network operating costs due to an expansion in the network operations activities

[393] Energex, email response, AER.EGX.30, 16 October 2009, pp. 4–5, confidential.

- increased vegetation management expenditure associated with improving overall rural SAIDI performance
- the introduction of a 15 month inspection cycle program on low voltage spurs
- identification and removal of high risk trees
- many light localised storm events
- input costs.

Energex noted that its inspection and planned maintenance opex fell due to increases in inspection intervals in some parts of its network. These changes arose because of the good performance of its network in the current regulatory control period.

QCA annual performanace reports

The AER has reviewed relevant annual performance reports prepared by the QCA. Some of the reasons identified by the QCA for the expected differences from Energex's regulated allowances are:[394]

- higher than forecast vegetation management costs
- costs associated with preparing for the introduction of full retail competition (FRC).

The QCA also noted Energex's contention that the higher expenditure largely reflects Energex's response to the Government's Electricity Distribution and Service Delivery Review (EDSD Review).[395]

8.4.2 Ergon Energy

Ergon Energy is expected to overspend its regulated opex allowance by approximately $78 million ($2009–10) or 5 per cent of the opex allowance approved by the QCA for the current regulatory control period.

Ergon Energy submitted that the following factors have contributed to the expected overspend in the current regulatory control period:[396]

- increased maintenance work being undertaken
- higher than forecast labour and contractor costs
- increased overall employee numbers
- a requirement for training expenditure to be completely expensed rather than partially capitalised

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394 QCA, *Financial and Service Quality Performance 2007–08: Energex*, March 2009, p. 4.
395 QCA, *Financial and Service Quality Performance 2007–08: Energex*, March 2009, p. 11.
396 Ergon Energy, *Regulatory proposal*, July 2009, p. 297

- increased network operations expense arising from the implementation of Project LINK[397]
- Information Communication and Telecommunications (ICT) costs being partially expensed rather than fully capitalised
- a change in charging methodology for Electricity Safety Office (ESO) fees.

QCA annual performance reports

The AER has reviewed relevant annual performance reports prepared by the QCA. Some of the reasons identified by the QCA for the expected differences from Ergon Energy's regulated allowances are:

- the implementation of full retail competition
- increased maintenance and emergency maintenance due to Cyclone Larry (2005–06) and floods (2007–08)
- reclassification of capex to opex.

The QCA noted the higher expenditure largely reflected Ergon Energy's response to the EDSD Review.[398]

8.4.3 Implications for the next regulatory control period

Energex

In terms of the implications for its review of Energex's forecast opex proposal, the AER observes that much of the overspend has been driven by increased work activity, and some higher than expected input costs.

The AER considers that Energex's overspend is explained by an increased work volume in response to the EDSD Review. The AER also notes that large increases in specific programs, such as vegetation management, were offset to some extent by a decrease in opex requirements in other areas (inspections and planned maintenance), due to decreases in work volumes.

Ergon Energy

The AER notes that increased labour costs have contributed to Ergon Energy's higher than forecast opex in 2007–08, and notes that the economic conditions at that time reflected a general tightening of the labour market. The increase in operations work volume is also mirrored by Ergon Energy's capex program which was also substantially higher than forecast for the current regulatory control period.

The AER considers that Ergon Energy's opex overspend is explained by changes to accounting methods, an increased work volume in response to FRC and the EDSD

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397 Project LINK refers to a program to enable remote monitoring and control of Ergon Energy's network as a single entity. The program included the construction of two 24 hour control centres in Rockhampton and Townsville and replacing monitoring technology with a new SCADA system.

398 QCA, *Financial and Service Quality Performance 2007–08: Ergon Energy*, March 2009, p. 6.

Review, and increased labour costs. The AER notes the changes generally reflect prevailing economic conditions or new regulatory obligations.

AER conclusion

In conclusion, the AER considers that the major reasons for the observed overspend are known to the Qld DNSPs and that these reasons have been taken into account by the Qld DNSPs in developing their regulatory proposals. This improves the likelihood that the DNSPs have presented a complete case on which the AER is able to assess the proposals against the opex criteria.

8.5 Queensland DNSP regulatory proposals

The AER's assessment of the Qld DNSPs' controllable opex proposals can be found in appendices I and J and is summarised in section 8.8 of this draft decision.

8.5.1 Energex

Table 8.3 shows Energex's forecast opex by cost category for each year of the next regulatory control period.

Table 8.3: Energex forecast total opex by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Network operating	25.5	26.8	27.4	28.3	28.9	137.0
Inspection	19.2	20.8	22.5	23.2	25.0	110.8
Planned maintenance	66.0	65.0	66.9	68.5	69.6	336.0
Corrective repair	40.0	41.1	41.4	41.9	42.1	206.4
Vegetation	77.2	79.5	81.1	82.2	82.5	402.6
Emergency response/storms	8.6	8.9	9.1	9.3	9.4	45.2
Meter reading	14.6	15.2	15.8	16.5	17.1	79.2
Customer services	21.0	21.9	22.4	23.1	23.6	111.9
DSM initiatives	24.6	23.2	25.3	30.6	23.2	126.9
Levies	8.6	8.9	9.2	9.5	9.9	46.1
Other support costs	19.2	18.8	19.3	18.6	17.9	93.8
Total controllable opex	324.5	330.0	340.4	351.6	349.2	1696.0
Self insurance	2.8	2.9	3.1	3.2	3.0	15.1
Debt raising costs	7.2	8.1	9.0	9.9	10.7	44.8
Equity raising costs	20.6	19.8	18.8	15.7	12.6	87.4
Total opex	355.1	360.9	371.3	380.4	375.5	1843.1

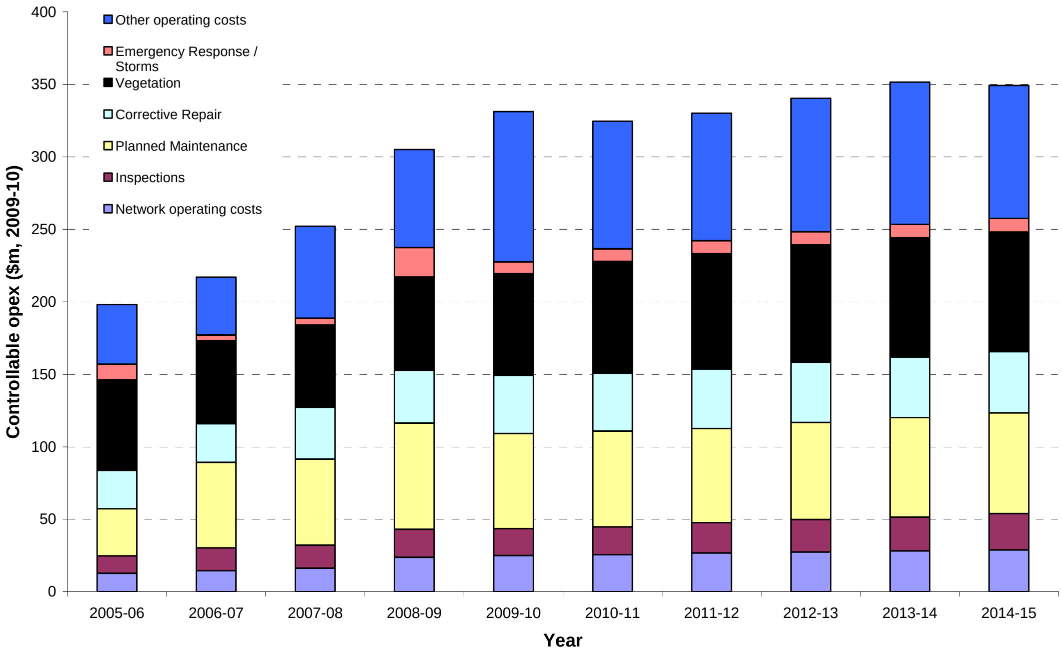
Source: Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2.
Note: Totals may not add due to rounding.

Energex's total forecast opex for the next regulatory control period is $1843 million ($2009–10) which is $491 million, or 36 per cent more than its expected opex in the current regulatory control period.[399]

Controllable opex

Figure 8.3 shows Energex's actual and expected controllable opex in the current regulatory control period, and its forecast for the next regulatory control period.

Figure 8.3: Energex actual and forecast controllable opex 2005–2015 ($m, 2009–10)



Source: Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2; AER analysis.

Energex's total controllable opex proposed for the next regulatory control period is $1696 million compared with an estimated $1352 million in the current regulatory control period, an increase of 25 per cent.[400] Energex submitted that the increase in opex for the next regulatory control period is being driven by:[401]

- new programs to progress toward EDSD Review and legislative compliance
- maintenance and management of an expanding asset base
- increased inspection and maintenance programs resulting from the introduction of a condition based risk management (CBRM) approach to asset renewal and refurbishment
- forecast customer growth

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[399] Energex, *Regulatory proposal*, July 2009, RIN opex pro forma 2.2.2, converted to real terms using ABS inflation data.

[400] Energex, *Regulatory proposal*, July 2009, RIN opex pro forma 2.2.2, converted to real terms using ABS inflation data.

[401] Energex, *Regulatory proposal*, July 2009, p. 183.

- real cost escalations.

Uncontrollable opex

Energex proposed to include $15 million for self insurance costs, $45 million for debt raising costs and $87 million in equity raising costs in its opex forecasts for the next regulatory control period.

8.5.2 Ergon Energy

Table 8.4 sets out Ergon Energy's forecast total opex by cost category for the next regulatory control period.

Table 8.4: Ergon Energy forecast total opex by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Network operations	26.4	26.3	26.7	27.2	27.5	134.1
Preventative maintenance	108.8	119.6	120.2	123.4	121.7	593.6
Corrective maintenance	121.9	121.5	122.8	117.9	105.7	589.8
Forced maintenance	41.0	40.8	41.3	41.4	41.1	205.7
Meter reading	11.8	11.8	11.8	12.0	12.3	60.4
Customer services	19.8	19.9	19.8	20.2	20.6	101.3
Other operating costs	36.3	37.4	38.0	39.5	41.0	192.2
Total controllable opex	365.9	377.3	381.2	382.3	370.2	1876.9
Self insurance	4.2	4.2	4.3	4.4	4.5	25.1
Debt and equity raising costs[a]	11.9	16.3	22.0	22.8	21.2	94.1
Total opex	382.0	397.8	407.5	409.5	395.9	1992.6

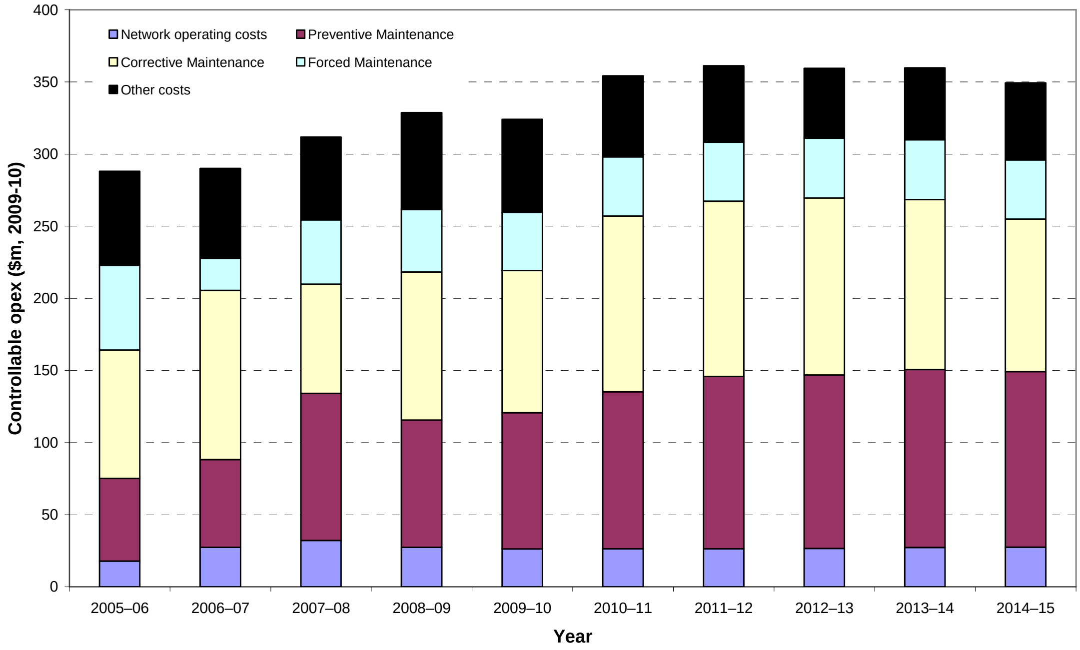
Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN proforma 2.2.2.
Note: Ergon Energy proposed a total opex allowance of $1898. This amount included self insurance costs but not equity and debt raising costs.
Totals may not add due to rounding.
(a) Ergon Energy's model includes an amount of $94.1 million for debt and equity raising costs. Ergon Energy has used an incorrect input which it sought for debt raising costs in the revenue modelling.

Ergon Energy's total forecast opex for the next regulatory control period is $1993 million which is $458 million, or 30 per cent more than its expected opex in the current regulatory control period.

Controllable opex

Figure 8.4 shows Ergon Energy's actual and expected controllable opex in the current regulatory control period, and its forecast for the next regulatory control period.

Figure 8.4: Ergon Energy actual and forecast controllable opex 2005–2015 ($m, 2009–10)



Source: Ergon Energy, *Regulatory proposal*, July 2009, RIN proforma 2.2.2; AER analysis.

The total proposed controllable opex of $1877 million in the next regulatory control period is 19 per cent higher than the estimated controllable opex of $1580 million ($2009–10) in the current regulatory control period.[402]

Ergon Energy submitted that the increase in controllable opex forecast for the next regulatory control period is being driven by:[403]

- more frequent and rigorous inspection regimes with flow on effects for corrective maintenance costs
- asset growth and input cost escalation
- increased work in respect of vegetation maintenance, access track repair and pole top inspections.

Uncontrollable opex

Ergon Energy proposed to include $21.5 million for self insurance costs[404], and $94.1 million for debt and equity raising costs[405] for the next regulatory control period.

402 Ergon Energy, *Regulatory proposal*, July 2009, pp. 259 (nominal converted to real $2009–10), 263, 305–306.
403 Ergon Energy, *Regulatory proposal*, July 2009, pp. 27–38.
404 In an email from Ergon Energy to the AER sent on 17 November 2009 (ERG.AER–XX, confidential), Ergon Energy advised that the self insurance amount listed in its regulatory proposal is incorrect. The correct amount is $21.5 million ($2009–10).

8.6 Submissions

The AER received submissions from the Energy Users Association of Australia (EUAA), Origin, Queensland Council of Social Service (QCOSS), Ergon Energy, Energex, Queensland Treasury Corporation (QTC) and SPA Consulting Engineers (SPA).[406] These submissions are discussed in further detail in this chapter and appendices I and J. In summary, submissions raised concerns regarding the following issues:

- prudence and efficiency of base year and forecast opex – interested parties sought assurances that the opex proposed by Energex and Ergon Energy are efficient. Origin stated that greater transparency regarding the proposed increase in opex would be valuable, and also noted the 86 per cent increase in opex between the previous regulatory control period and the current regulatory control period. Origin stated it was not apparent that 2007–08 was an appropriate base year.[407]

- growth and general trends in opex allowances – the EUAA raised concerns about the growth of opex, stating that it was hard to reconcile this growth with the fact that these businesses are mature technology utility businesses.[408] It also stated that opex has grown much faster than growth in customer numbers or peak demand. It submitted that the AER should consider what the DNSPs have achieved before contemplating further increases in expenditure.[409]

- benchmarking – the EUAA submitted that there is a requirement in the NER for the AER to benchmark efficient expenditures in making its regulatory distribution determination.[410] The EUAA suggested that the AER should define the benchmark efficient opex against which the expenditure proposals of the Qld DNSPs are to be compared. It stated the evidence provided by such analysis needs to be considered by the AER in reaching its decision.[411] It also stated that there is no scope for the AER to only benchmark to test bottom up conclusions.[412] Origin submitted that, in light of limited benchmarking analysis by the DNSPs, it is important that the AER develops a standard framework for benchmarking for DNSPs, allowing information to be collected on a 'like for like' basis, with transparent means for correcting differences between distributors.[413]

- demand management – the EUAA commented that demand management expenditure for both businesses needs to be economically robust, and that the AER needs to carefully assess the benefits of such expenditure.[414] The EUAA stated that most of the demand management budget is opex. It considered that, if

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405 Ergon Energy, *Regulatory proposal*, July 2009, p. 306.
406 EUAA, *Submission to the AER*, August 2009; Origin, *Qld DNSPs*, August 2009; QCOSS, *Response to Queensland DNSPs*, August 2009; and SPA, *Submission to the AER*, August 2009.
407 Origin, *Queensland DNSPs*, August 2009, p. 5.
408 EUAA, *Submission to the AER*, August 2009, pp. 2–3.
409 EUAA, *Submission to the AER*, August 2009, p. 19.
410 EUAA, *Submission to the AER*, 28 August 2009, p. 11.
411 EUAA, *Submission to the AER*, 28 August 2009, p. 15.
412 EUAA, *Submission to the AER*, August 2009, section 3.
413 Origin, *Queensland DNSPs*, August 2009, p. 7.
414 EUAA, *Submission to the AER*, August 2009, p. 19.

this expenditure is simply to defer demand growth then it is not likely that the benefits will exceed the costs. The QCOSS also raised concerns about demand management expenditure, stating that a ‘broad brush roll out’ will not serve to avoid or defer network augmentation investment.[415]

- interest rate risk hedging costs – Energex, Ergon Energy and the Queensland Treasury Corporation (QTC) submitted that the cost of hedging interest rate risk on borrowing is prudent and should be compensated for.[416]

8.6.1 Energex

The AER received submissions from the EUAA and Origin relating to Energex’s proposed opex for the next regulatory control period, raising the following issues:

- benchmarking – Origin questioned the usefulness of Energex’s benchmarking, and stated that in light of the proposed opex increases, the benchmarking Energex relies on in section 12.10 of the regulatory proposal should be made more transparent.[417]

- opex growth – the EUAA commented on Energex’s capex and opex growth and stated that growth in these areas is far greater than growth in customer numbers. The EUAA stated that the AER should carefully examine what has been achieved before approving further expenditure.[418] The EUAA also stated that the AER must ensure that a much higher level of cost/benefit analysis is conducted before considering the approval of Energex’s expenditure proposal.[419]

- ring fencing – the EUAA commented on Energex’s ring fencing arrangements, and stated that the AER needs to examine in detail how Energex has ring fenced its regulated and non–regulated businesses in terms of costs and revenue to ensure that unregulated businesses are not being compensated.[420]

- debt and equity costs – the EUAA stated that the debt and equity raising costs proposed by Energex seem unreasonable. The EUAA suggested that, as the Queensland Government arranges Energex’s debt and equity, there should be no costs allowed for these cost categories.[421]

- efficient base year – Origin commented on Energex’s choice of base year, stating that the current regulatory control period should only be a precursor to further spending if Energex is making reasonable progress towards its stated goals. Further, Origin would like further information on the trajectory that Energex envisages to reach these goals.[422]

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415 QCOSS, *Response to Qld DNSPs*, August 2009, p. 5.
416 SFG, *Consistency in regulatory assumptions in relation to debt hedging costs; Report prepared for Energex and Ergon Energy*, August 2009; and QTC, *Hedging Cost Submission*, August 2009.
417 Origin, *Queensland DNSPs*, August 2009, p. 7.
418 EUAA, *Submission to the AER*, August 2009, p. 19.
419 EUAA, *Submission to the AER*, 28 August 2009, p. 20.
420 EUAA, *Submission to the AER*, August 2009, p. 19.
421 EUAA, *Submission to the AER*, August 2009, p. 20.
422 Origin, *Queensland DNSPs*, August 2009, p. 5.

- vegetation management – Origin stated that Energex should clearly state whether the increase in vegetation management spending is based solely on higher rainfall or whether vegetation management goals will be met quicker as a result of this spending. Origin also stated that some information on the extent to which these increases are driven by unit costs would be useful.[423] Further, Origin would like more information on the revised contractor strategy and the cost impacts of this revision.[424]

8.6.2 Ergon Energy

The EUAA stated that there was no information on proposed productivity improvements in Ergon Energy's opex program, even though all businesses should display continuous productivity improvements, including network monopolies.[425]

8.7 Consultant review

The AER engaged PB to provide an independent review to assess the prudence and efficiency of the Qld DNSPs' controllable opex forecasts for the next regulatory control period.[426]

PB adopted a phased approach to review the proposed opex allowances. PB's process was to provide broad coverage of the opex proposal while enabling a more detailed examination of particular issues, on the basis of materiality or changing expenditure patterns. The approach adopted by PB involved:[427]

- detailed desk–top review of the regulatory proposals
- onsite meetings with the Qld DNSPs' staff to discuss essential elements of their regulatory proposals
- development of a preliminary view on key issues
- discussion and agreement with the AER to a scope of works for the focussed review stage
- further discussions with the Qld DNSPs to establish a full understanding of specific expenditure items in the focussed second stage.

PB's review of the Qld DNSPs' proposed opex included an assessment of:[428]

- the efficiency of the forecast opex for each year of the next regulatory control period, and whether there was any further scope for efficiencies
- the appropriateness of the allocation of opex costs to specific activities

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423 Origin, *Queensland DNSPs*, August 2009, p. 6.
424 Origin, *Queensland DNSPs*, August 2009, pp. 6–7.
425 EUAA, *Submission to the AER*, August 2009, p. 19.
426 PB, *Report – Energex*, October 2009; and PB, *Report – Ergon Energy*, October 2009.
427 PB, *Report – Energex*, October 2009, p. 4.
428 PB, *Report – Ergon Energy*, October 2009, pp. 5–6.

- the effectiveness of operating practices, procedures, and asset management systems at ensuring only necessary and efficient opex occurs
- the major factors (drivers) that may affect the level of efficient opex required over the next regulatory control period
- the appropriateness of the opex forecasting methodology, including:
  - reviewing the opex by cost category in both the current and next regulatory control periods, including trends and changes in each line item
  - reviewing the variations between the opex in the final year of the current regulatory control period and opex in the first year of the next regulatory control period (step changes in expenditures)
- the reasonable application of escalation factors used to forecast expenditures
- assessing the appropriateness of efficiency factors used to reflect the impact of economies of scale and scope
- assessing the efficiency of labour and material costs used to forecast expenditures
- whether insurance costs captured by self insurance have been appropriately excluded
- the impact of proposed capital works to be commissioned during the next regulatory control period on forecast opex.

PB's review of the Qld DNSPs' forecast opex specifically excluded an assessment of uncontrollable opex items including self insurance, debt and equity raising costs and interest rate hedging costs.[429] The AER has analysed these aspects of the Qld DNSPs' proposals.

Energex

Based on its review, PB found Energex's proposed controllable opex to be prudent and efficient, except for some forecast expenditures relating to demand management. PB's key findings were:[430]

- Energex's asset management principles, processes and procedures are prudent and efficient with the implementation of CBRM considered by PB to be at the forefront of industry practice
- Energex's key policy documentation and policies were prudent
- Energex's bottom up forecasting methodology was sound and was likely to result in accurate forecasts

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429 PB, *Report – Energex*, October 2009, p. 6, and; PB, *Report – Ergon Energy*, October 2009, p. 6.
430 PB, *Report – Energex*, October 2009, pp. 119–120.

- there were two real step changes in Energex's forecast opex program – vegetation management and demand management
- Energex's forecasts for the following cost categories were prudent and efficient based on the business as usual trends and the detailed bottom up forecasting methodology:
  - network operations
  - inspections
  - planned maintenance
  - corrective repair
  - vegetation management
  - emergency response/storms
  - customer service
- demand management opex has been reduced by $2.2m to reflect a demand management project that had a negative Net Present Value (NPV) and no effect on overall demand reduction
- a proportion of the expensed overheads relating to ICT services provided by SPARQ solutions (SPARQ) is not prudent and efficient and should be reduced by $2.2 million.

PB's analysis involved removing the effects of real cost escalation to examine the effects of opex increases related to growth in asset volumes. Through this process, PB identified two cost categories for which there are proposed step changes when comparing the final year of the current regulatory control period with the first year of the next regulatory control period. The step changes identified by PB were vegetation management and demand management.[431]

PB concluded that Energex's controllable opex of $1.7 billion was prudent and efficient, with the exception of some demand management expenditure and an element of expensed overheads relating to ICT services.[432] PB's recommended adjustment to these categories resulted in an indicative reduction to controllable opex of $4.4 million in the next regulatory control period.[433] PB did not review the cost escalators applied by Energex and therefore have not made any adjustment for revised escalators.

Table 8.5 compares Energex's opex forecasts with PB's recommended opex forecasts.

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[431] PB, *Report – Energex*, October 2009, p. 97.
[432] PB, *Report – Energex*, October 2009, pp. 119–121.
[433] PB, *Report – Energex*, October 2009, pp. 119–121.

Table 8.5: Energex forecast controllable opex and PB recommended opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex controllable opex forecast	324.5	330.1	340.4	351.7	349.2	1696.0
Less PB adjustments	–2.3	–0.6	–0.5	–0.4	–0.5	–4.4
PB recommended controllable opex	322.2	329.5	339.9	351.3	348.7	1691.6

Source: PB, *Report – Energex*, October 2009, pp. 17 and 112–116.
Note: Totals may not add due to rounding.

Ergon Energy

PB found Ergon Energy's proposed controllable opex to be largely prudent and efficient, except for the forecast expenditures relating to vegetation management, forced maintenance, corrective maintenance, customer services, meter reading and an element of the expensed overheads relating to ICT services. PB's key findings were:

- Ergon Energy's policies, documentation and modelling to support the asset management approach and the forecasting methodology are comprehensive, transparent and reflect the needs of the business in the current environment
- in general, the opex forecasting approach adopted by Ergon Energy is reasonable and transparent, based on either a detailed bottom up view of asset quantities or work volumes across key asset categories in all material areas, or a pragmatic top down view – informed by historical experience – in the areas where a detailed bottom view is not practical
- the opex forecasting approach used by Ergon Energy included only a simplistic view of growth escalation, and does not suitably capture the actual capex program proposed, nor integrate the various strategies, including capex/opex trade off, effectively
- asset maintenance and management practices are in a transitional stage. The current approach includes lagging indicators and fixed time based inspections. The future approach will capture more condition based knowledge and be informed through leading indicators, reflecting a strategic increase in preventative maintenance requirements
- in comparison with a small sample of Australian peers, Ergon Energy's opex forecasts appear relatively high from a top down perspective using a composite size variable to normalise the business expenditure

PB recommended that Ergon Energy's proposed opex allowance should be reduced by $188 million ($2009–10),[434] or about 10 per cent. The reductions relate to network maintenance activities and other operating costs proposed by Ergon Energy. PB did

[434] This amount is inclusive of PB's recommended reduction in SPARQ ICT opex of $5.1 million.

not review the cost escalators applied by Ergon Energy and therefore has not made any adjustment for revised escalators.

Table 8.6 presents PB's recommended controllable opex allowance for Ergon Energy for the next regulatory control period.

Table 8.6: PB recommended opex allowance for Ergon Energy ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	370.1	381.4	385.4	386.6	374.7	1898.2
PB adjustments	–31.6	–35.1	–38.3	–41.3	–41.5	–187.8
PB recommendation	338.5	346.3	347.1	345.3	333.2	1710.4

Source: PB, *Report – Ergon Energy*, October 2009 p. 148.
Note: Totals may not add due to rounding.

8.8 Issues and AER considerations

The AER must determine whether the opex forecasts of the Qld DNSPs reasonably reflect the efficient costs that a prudent operator in the circumstances of the DNSP would require to achieve the opex objectives.[435]

The AER considers that PB's detailed bottom up assessment, supported by top down observations and analysis, is an appropriate and comprehensive method of assessing efficient costs. This approach allows the AER to consider whether the opex proposals are efficient and prudent, and satisfy the conditions set out in chapter 6 of the NER.

The AER notes that the majority of issues raised by stakeholders in their submissions have been considered in the AER's assessment of the forecast opex proposals. In particular, the submissions expressed concerns about the large increases in opex relative to historical expenditure and the need to ensure such expenditures are justified. The AER considers that these concerns have been appropriately considered in PB's assessment, and its own independent consideration of the opex proposals, based on the approach discussed in section 8.3 of this draft decision. Specifically, the AER and PB assessed, among other things:

- the appropriateness of the forecasting methods and procedures used by the Qld DNSPs, including a review of the allocation of costs in accordance with the AER approved cost allocation methods (CAM)
- the efficiency of the Qld DNSPs' base year and forecast opex, using a detailed bottom up approach where possible, and with reference to benchmarking studies
- the impact and reasonableness of proposed real input cost escalators and network scale/growth escalators

[435] NER, clause 6.5.6(c).

- step changes in opex, the rationale for those changes and the associated efficiency benefits
- the scope for capex/opex trade offs and efficient demand management initiatives.

In addition, the AER has undertaken analysis of the reasonableness and efficiency of the Qld DNSPs' uncontrollable opex forecasts. These considerations are set out in section 8.8.5.

An overview of the AER's key considerations relating to the Qld DNSPs' forecast opex proposals is set out below. The AER's detailed considerations of the controllable opex components of the forecasts are set out at appendices I and J.

8.8.1 Energex – controllable opex

The AER's review of proposed opex programs is undertaken separately to its review of input cost escalators (section 8.8.6 of this draft decision). The impact of revisions to input cost escalators is therefore not factored into the AER's conclusions in this section. The consolidated impact of all adjustments required by the AER (controllable opex, uncontrollable opex, capex/opex trade offs, and input cost escalation) is set out in section 8.9 of this draft decision.

Forecasting methodology

Energex utilised a two part process to determine its opex forecasts for the next regulatory control period. Energex constructed its opex forecasts using a bottom up approach, followed by a top down review which assessed the resulting forecasts against industry accepted efficiency benchmarks. Energex's approach incorporated Wilson Cook's methodology in its assessment of efficient opex forecasts.[436] This approach found a composite variable of customer numbers and line length, compared with opex provided the best correlation with total opex.[437]

Energex advised that it develops its opex forecasts based on its Network Strategy.[438] It also indicated its opex forecasts are underpinned by key internal documents, namely its substation asset maintenance policy (SAMP) and mains asset maintenance policy (MAMP). Energex stated that these documents provide it with a basis upon which to build its bottom up opex forecasts, while ensuring compliance with relevant legislation.[439]

PB reviewed Energex's opex forecasting methodology and found that the forecasting methodology was likely to result in accurate and reasonable forecasts. In particular, PB highlighted the following:[440]

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436 Wilson Cook & Co, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs,* Volume 1, October 2008, pp. 18–27.
437 Energex, *Regulatory proposal*, July 2009, p. 160.
438 Energex, *Regulatory proposal*, July 2009, p. 162. For a summary of Energex's Network Strategy see Energex, *Regulatory proposal*, July 2009, pp. 63–77.
439 Energex, *Regulatory proposal,* July 2009, p. 162.
440 PB, *Report – Energex*, October 2009, p. 99.

- most expenditure categories have been forecast based on historical quantities, adjusted to reflect the proposed capex program
- average unit costs were used based on historical actual costs and were reviewed to ensure total costs aligned with the number of units maintained
- where historical trends have been used in forecasting, these have been observed over sufficient periods to counter the impacts of annual variability (for example, changing weather patterns and the impact on emergency response expenditures).

The AER reviewed Energex's compliance and maintenance documentation in conjunction with PB's report, and considers that Energex's bottom up forecasting methodology is comprehensive and is likely to produce efficient opex forecasts.

Efficient base year and benchmarking

Energex used a bottom up opex forecasting methodology to build its opex forecasts, with the 2007–08 base year data being used to illustrate the efficiency of its current and forecast opex program.

The AER undertook a ratio analysis and benchmarking exercise, which is discussed in detail in appendix I of this draft decision, to assist in assessing the relative efficiency of Energex's current opex program. The AER provided its ratio analysis to PB. PB considered the results in conjunction with Energex's internal benchmarking and considered that Energex's opex forecasts are relatively efficient from a top down, inter-business comparison.[441]

The AER's regression analysis compares 2007–08 data of Australian DNSPs. Consistent with the ratio analysis undertaken by the AER, and Energex's internal benchmarking, the AER's regression modelling shows that Energex lies below the regression line, indicating it has relatively low opex in 2007–08, in comparison to other Australian DNSPs in the sample.

The AER has had regard to its own internal benchmarking analysis in accordance with the NER, and observes that, consistent with Energex's benchmarking results, Energex's opex appears relatively efficient in 2007–08 compared to the sample. Results from the AER's benchmarking studies are discussed further in appendix I.

The AER notes that benchmarking is one of only ten factors which the AER must have regard to when assessing the relative efficiency of a DNSP's opex forecasts. The AER thus considers that, while benchmarking is a useful analytical tool, its use should be limited to a top down test of more detailed bottom up assessments.

Network operating costs

Energex proposed a total of $137 million in relation to network operating costs in the next regulatory control period.

PB compared the real changes in forecast opex with past network operations opex and stated there was a business as usual expenditure pattern. Given the business as usual

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[441] PB, *Report – Energex*, October 2009, pp. 117–119.

trend, and the detailed approach Energex used when forecasting opex for the next regulatory control period, PB recommended that the proposed opex for network operations should be accepted with no change.[442]

The AER notes that the increases in network operating costs were primarily driven by costs associated with compliance with a stricter interpretation of the *Electrical Safety Act (2002)*, limiting the amount of work that can be completed on live equipment. This has increased costs associated with switching and after hours access.[443] The AER considers Energex has appropriately modelled its network operations expenditures.

Network maintenance

Inspections

Energex proposed a total of $111 million in relation to inspections opex for the next regulatory control period.[444] Energex stated that the primary drivers of its inspections opex are the introduction of the CBRM asset management system and the capital works program.[445]

PB advised that its top down review indicated a business as usual inspections opex pattern from 2008–09 onwards, but noted inspection quantities were forecast to increase. PB reviewed the underlying causes of the increase in inspection volumes and stated the forecasts were reasonable. PB recommended that the forecast inspection expenditures should be accepted with no change.[446]

The AER notes PB's report, as well as its own analysis, and considers that an increase in inspections expenditure is likely due to the introduction of the CBRM asset management methodology. The AER also determined that the proposed inspections expenditures are in line with the proposed capex program. Overall, the AER considers that Energex has appropriately modelled its inspections expenditures.

Planned maintenance

Energex proposed a total of $336 million in relation to planned maintenance for the next regulatory control period.[447] Energex stated that its planned maintenance program was a direct result of its inspections program, and as such is influenced by the introduction of CBRM. For example, the introduction of more inspections may identify more assets that require planned maintenance.[448]

PB indicated a reducing trend in planned maintenance expenditure over the next regulatory control period and confirmed Energex's planned maintenance forecasts were constructed from a combination of forecast maintenance based on the SAMP and MAMP, historical defect ratios associated with the quantity of forecast inspections and average unit costs for the 2008–09 financial year.[449] PB

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442 PB, *Report – Energex*, October 2009, pp. 100–101.
443 Energex, *Regulatory proposal*, July 2009, p. 185.
444 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
445 Energex, *Regulatory proposal*, July 2009, pp. 186–187.
446 PB, *Report – Energex*, October 2009, p. 102.
447 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
448 Energex, *Regulatory proposal*, July 2009, p. 186.
449 PB, *Report – Energex*, October 2009, p. 103.

recommended that, given the detailed forecasting methodology and overall decrease in expenditure for this category, the planned maintenance forecast should be accepted with no change.[450]

The AER considered PB's report, and Energex's forecasting methodology, including the likely capex/opex trade off for planned maintenance activities. Based on the methodology that Energex employed, the AER considers that Energex has appropriately incorporated its capex program into its planned maintenance forecasts. Overall, the AER considers Energex has appropriately modelled its planned maintenance expenditures.

Corrective repair

Energex proposed $206 million in relation to corrective repair in the next regulatory control period.[451]

PB stated corrective repair opex shows a business as usual expenditure pattern from 2008–09 onwards and recommended that the opex forecasts for corrective repair be accepted with no change.[452]

The AER notes that the increase in corrective repair opex has been primarily driven by the implementation of a new internal policy, where more costs have not met the threshold to be booked as emergency response/storms costs, and have thus been booked as corrective repair costs.[453] The AER considers Energex has appropriately modelled its corrective repair expenditures.

Vegetation management

Energex proposed a total of $403 million in relation to vegetation management for the next regulatory control period.[454] Energex stated that the primary driver of growth in this category was the decision to reduce the trimming cycles on all low voltage urban lines from 30 to 15 months, brought about by a return to 'more typical' rainfall, together with the introduction of a visual tree assessment program.[455]

PB noted a $4.8 million step change in real terms between 2009–10 and 2010–11 for vegetation management expenditure. PB concluded that the primary reason for the additional expenditure related to the proposed introduction of reduced trimming cycles on low voltage urban lines. It also indicated that Energex had received improvement notices from the Electricity Safety Office (ESO) to maintain statutory clearances.[456] PB recommended that the proposed vegetation expenditure be accepted with no changes in order to allow Energex to fulfil its regulatory and legislative obligations.[457]

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450 PB, *Report – Energex*, October 2009, pp. 103–104.
451 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
452 PB, *Report – Energex*, October 2009, p. 105.
453 Energex, email response, AER.EGX.30, 27 October 2009, confidential.
454 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
455 Energex, *Regulatory proposal*, July 2009, pp. 186–187.
456 PB, *Report – Energex*, October 2009, p. 106.
457 PB, *Report – Energex*, October 2009, p. 107.

The AER notes the step change in Energex's vegetation management opex. The AER considers the main drivers for this step change (increased rainfall in the Brisbane area and a requirement to correct infringements notified by the ESO) have been well documented and correctly modelled by Energex. The AER considers Energex has appropriately modelled its vegetation management opex.

Emergency response/storms

Energex proposed a total of $45 million in relation to emergency response/storms over the next regulatory control period.[458] Due to the unpredictable nature of storms, Energex used a long term average number of storm events, over eight years, to estimate the opex for this category.[459]

PB noted that there was a 10 per cent increase in emergency response/storms expenditure over the next regulatory control period. This increase is derived from the increase in assets under management resulting from the proposed growth related capital works program.[460] PB recommended that Energex's emergency response/storms opex expenditure should be accepted with no change.[461]

The AER notes that Energex has used historical averages to forecast its emergency response/storms expenditure for the next regulatory control period.[462] The AER considers that this will smooth out the significant variability that can occur within this cost category, and as such the AER considers that Energex's emergency response/storms forecasting methodology is sound. The AER considers Energex has appropriately modelled its emergency response/storms expenditures.

Other opex

Meter reading

Energex proposed a total of $79 million in relation to meter reading for the next regulatory control period.[463]

PB advised the largest component of meter reading costs is meter reading activities, which are subject to a periodic competitive tendering process to ensure current market costs and service levels are maintained. PB noted the meter reading forecasts were based on forecast customer numbers, which explained the increasing expenditure trend in the next regulatory control period.[464] PB recommended that the meter reading opex forecasts should be accepted with no change.[465]

The AER notes PB's advice that a significant proportion of meter reading expenditure is related to costs that are based on contractor rates. These costs are periodically subject to competitive tender, and as such ensure that efficient market costs are

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458 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
459 Energex, *Regulatory proposal*, July 2009, p. 167 and 187.
460 PB, *Report – Energex*, October 2009, p. 108.
461 PB, *Report – Energex*, October 2009, pp. 108–109.
462 Energex, *Regulatory proposal*, July 2009, p. 167.
463 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
464 PB, *Report – Energex*, October 2009, p. 110.
465 PB, *Report – Energex*, October 2009, p. 110.

incurred.[466] The AER also notes that the average over the next regulatory control period is slightly lower, before real cost escalations are applied, than the average for the current regulatory control period.

The AER considers Energex has appropriately modelled its meter reading opex costs.

Customer services

Energex proposed a total of $112 million in relation to customer services for the next regulatory control period.[467] Energex stated that the primary driver behind the increase in customer services expenditure was the establishment of new call centres after Energex's retail business was sold.[468]

PB advised that the annual real forecasts for customer services expenditure are at the same level as the 2009–10 financial year, the first year in which Energex's new customer services arrangements were implemented.[469] On this basis, PB recommended that the opex forecasts for customer services should be accepted with no change.[470]

The AER notes the a step change implicit in Energex's customer services forecasts relates to the sale of Energex's retail and gas businesses, and the subsequent loss of economies of scale in relation customer service activities. Energex was required to establish several customer service initiatives subsequent to the sale of the retail and gas businesses. The AER is satisfied that Energex has excluded any one off costs arising from the establishment of its customer service regime from its forecasts.

The AER has also reviewed Energex's forecast of GSL payments, and the QCA's recent decision on updating the Minimum Service Standards and Guaranteed Service Levels (GSL).[471] GSL payments are incurred when the network service provider fails in its duty to provide a reliable service. In essence, GSL payments are a mechanism designed to encourage the network service provider to deliver a reliable and safe service.

The AER considers that Energex's forecast of GSL payments is consistent with its historical levels of GSL payments and notes that the GSL forecast payments have been updated (in real terms) where relevant to reflect revised payment schedules. The AER considers Energex has appropriately modelled its customer services expenditures.

Demand side management initiatives

Energex's proposed demand management program has nine programs designed to address the balance between supply and demand through non–network alternatives. Energex forecast opex of $127 million in relation to demand management in the next regulatory control period.

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466 PB, *Report – Energex*, October 2009, p. 110.
467 Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
468 Energex, email response, PB.EGX.VP.57, 26 August 2009, confidential.
469 PB, *Report – Energex*, October 2009, p. 111.
470 PB, *Report – Energex*, October 2009, pp. 111–112.
471 QCA, *Final decision, electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010*, April 2009.

PB's analysis of Energex's demand management program involved an examination of a business plan of each initiative. PB's conclusions regarding the efficiency of the projects were based on each project's net impact on network demand and Net Present Value (NPV) analysis.[472] The AER considers that this approach is an appropriate method of assessing the efficiency of a demand management program. Based on PB's analysis, the AER considers that a reduction of $2.2 million to forecast demand side management initiatives is required to exclude the demand and energy data capture and analysis program, which had a negative NPV and no impact on peak system demand.

Levies

Energex's forecast levies expenditure is related to payments required under the *Electrical Safety Act (2002)* (payments to the ESO) and the *Queensland Competition Authority Amendment Regulation (No.1) 2003* (payments to the QCA).[473] Energex proposed a total of $46 million in relation to levies opex in the next regulatory control period.[474]

The AER investigated the calculation of these payments, and was satisfied that Energex had applied the correct methodology of calculating these levies into its opex forecasts.

Other support costs

Energex proposed a total of $93.8 million in relation to other support costs, which included expenditures in relation to sponsorships and stock write offs.[475]

The AER considers that Energex has not demonstrated that the inclusion of sponsorships and stock write offs within this opex category is consistent with the NER. In particular, the AER is concerned that these costs do not relate to the provision of standard control services. The AER is not satisfied that the opex proposed by Energex in relation to other support costs reasonably reflects the opex criteria, including the opex objectives. The AER considers that a reduction of $10.8 million to Energex's other support costs (reflecting the forecast opex for sponsorship and stock write offs) is required for Energex's opex forecasts to comply with the NER.

Shared costs – ICT costs

Energex proposed a total of $119 million in ICT shared costs to be allocated to opex. These costs are allocated across Energex's capex and opex programs in accordance with Energex's CAM. Energex's shared costs are discussed in detail in section F.5.4.6 of this draft decision. As a result of the reasons discussed, the AER is not satisfied that the proposed ICT shared costs reflect the opex criteria, including the opex objectives. As a result, the AER considers that a reduction of $2.2 million is necessary.

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[472] PB, *Report – Energex*, October 2009, p. 115.
[473] Energex, *Regulatory proposal*, July 2009, p. 170.
[474] Energex, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, confidential.
[475] Energex, *Regulatory proposal*, July 2009, pp. 171–172, and RIN proforma 2.2.2, confidential.

Superannuation

The AER notes that Energex included superannuation costs within its opex forecasts as labour on–costs. The AER has examined the financial statements of Energex[476] and accepts that obligations and payments in relation to defined benefit superannuation schemes are imposed by the *Occupational Superannuation Standards Regulations (1987)*.[477]

The level of payments to be made by Energex in respect of defined benefits superannuation schemes have increased due to the volatility within financial markets over the past two years. However, the AER considers that as financial markets stabilise, Energex's financial obligations in respect of defined benefit superannuation schemes will decline. The AER expects updated information regarding the financial obligations of Energex in respect to defined benefit superannuation schemes to be reflected in its revised regulatory proposal. The AER also notes that a significant revision to such financial obligations may constitute negative pass through events in the next regulatory control period.

8.8.2 AER conclusion - Energex controllable opex

Table 8.7 sets out the AER's adjustments to Energex's forecast controllable opex allowance. These adjustments are derived from the opex model and reflect the AER's conclusion on an efficient controllable opex. The adjustments do not include the impact of the AER's revised input cost escalators.

Table 8.7: AER adjustment to Energex's controllable opex, excluding input cost escalation ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex's proposed controllable opex	324.5	330.0	340.4	351.6	349.2	1695.7
Adjustment to demand management	–2.2	0	0	0	0	–2.2
Adjustment to other support costs	–2.2	–2.2	–2.2	–2.2	–2.1	–10.8
Adjustment to overheads/shared ICT costs	–0.1	–0.6	–0.5	–0.4	–0.5	–2.1
AER adjusted controllable opex (excluding input cost escalators)	320.0	327.2	337.7	349.0	346.5	1680.5

8.8.3 Ergon Energy

The AER's review of proposed opex programs is undertaken separately to its review of input cost escalators (section 8.8.6 of this draft decision). The impact of revisions

476 Energex, *Annual Report, 2008–09*.
477 Occupational Superannuation Standards Regulation 1987, clause 18Y. Accessed from Australian Legal Information Institute, http://www.austlii.edu.au/au/legis/cth/consol_reg/ossr513/.

to input cost escalators is therefore not factored into the AER conclusions in this section. The consolidated impact of all adjustments required by the AER (controllable opex, uncontrollable opex, capex/opex trade offs, and input cost escalation) is set out in section 8.9 of this draft decision.

Forecasting methodology

Ergon Energy used both baseline/scope change and bottom up methodologies to forecast its opex for the next regulatory control period.

Ergon Energy stated that its baseline/scope change approach involved using 2007–08 actual opex as the baseline then making adjustments for abnormalities and workload growth. Ergon Energy used a bottom up process for deriving cost estimates where it considered that the baseline/scope change approach did not provide efficient estimates for specific components of opex. The bottom up approach involved multiplying quantities of specified work by the relevant unit rates for the specified work.[478]

Each category of opex was escalated for increases in input costs and network growth. Ergon Energy used Sinclair Knight Mertz (SKM) labour and commodity escalation rates to model the impact of future cost drivers.[479] Ergon Energy also included a 3 per cent annual productivity improvement in its opex forecasts.[480]

PB considered that the methodology used by Ergon Energy was pragmatic and generally an accurate approach to forecasting opex.[481] PB noted that the approach was aligned with Ergon Energy’s business asset management framework. PB stated that the policies, documentation and modelling align to support the asset management approach. It noted that Ergon Energy’s forecasting methodology was comprehensive and transparent and it reflected the needs of the business in the current environment.[482]

However, PB noted that Ergon Energy did not explicitly incorporate any capex/opex trade off adjustments as part of its preventative or corrective maintenance opex forecasts. PB considered that a reduction should be made to opex forecasts as Ergon Energy’s large asset replacement capex program in the next regulatory control period should reduce the need to carry out opex activities.[483] Accordingly, PB recommended a reduction of $9.7 million ($2009–10) in the proposed preventative and corrective maintenance forecast opex to account for capex/opex interactions.

The AER accepts the general modelling framework described by Ergon Energy as a pragmatic approach to forecasting opex for the next regulatory control period.

However, the AER does not consider that Ergon Energy has suitably accounted for the impact of the significant replacement capex program on preventative and corrective maintenance. For this reason, the AER requested Ergon Energy to adjust its

478 Ergon Energy, *Regulatory proposal*, July 2009, pp. 267–268, 276–277, 328–330.
479 Ergon Energy, *Regulatory proposal*, July 2009, pp. 78, 273–274, 276–277.
480 Ergon Energy, *Regulatory proposal*, July 2009, p. 29.
481 PB, *Report – Ergon Energy*, October 2009, pp. 109–110.
482 PB, *Report – Ergon Energy*, October 2009, p. 144.
483 PB, *Report – Ergon Energy*, October 2009, pp. 116–118. See chapter 7 of this draft decision for further details on the capex program.

modelling to explicitly account for the estimated capex/opex trade off using the methodology applied by PB.[484] This has impacted on forecasts of corrective and preventative maintenance opex.

Efficient base year

Ergon Energy used its 2007–08 opex as the base year to forecast its network operations, corrective maintenance, components of forced maintenance and other opex in the next regulatory control period. Ergon Energy stated that it selected 2007–08 as the base year as it provided a sound basis for preparing the opex forecasts.[485]

Ergon Energy stated that the regulatory accounts for 2007–08 have been audited and provided the AER with a copy of the auditors report. The auditors report stated the regulatory statement fairly represented Ergon Energy's financial position and was prepared using the correct CAM.[486]

Where the baseline/scope change approach was used to estimate costs, Ergon Energy stated that the 2007–08 base year represented business as usual costs for each of the cost categories. The base year opex was adjusted for abnormalities. Scope changes were added to the base year opex if a change in the level of work activity was forecast throughout the next regulatory control period. The adjusted base year opex was then inflated to reflect future price movements.[487]

Ergon Energy engaged Benchmark Economics to conduct benchmarking of its operating performance.[488] Benchmark Economics found that Ergon Energy was operating above the trend line, which suggests that its opex is relatively high compared to the other DNSPs.

The AER notes that Ergon Energy overspent by 10 per cent (nominal) compared to its total opex allowance for the current regulatory control period determined by the QCA.[489] Ergon Energy's over spend was around 3 per cent in 2007–08.

The AER notes that increased labour costs contributed to Ergon Energy's higher than forecast opex in 2007–08.[490] The increase in labour costs occurred because of the boom in economic conditions at that time, causing a general tightening of the labour market in Queensland. The increase in operations work volume is also mirrored by Ergon Energy's capex program which was also substantially higher than forecast for the current regulatory control period.

The AER is aware there was an increase in Ergon Energy's work volume which arose from the general increased economic activity in Queensland, and Ergon Energy's response to the EDSD Review. Changes to Ergon Energy's accounting policies also

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484 AER, modelling request, 6 November 2009.
485 Ergon Energy, *Regulatory proposal*, July 2009, p. 274, 277 and 279.
486 Ergon Energy, *Regulatory proposal*, July 2009, attachment AR370c, confidential.
487 Ergon Energy, *Regulatory proposal*, July 2009, pp. 266, 269, 274, 277, 279, 289–290 and 293–294.
488 Benchmark Economics is an independent economic consulting firm.
489 Ergon Energy, *Regulatory proposal*, July 2009, p 296, table 76.
490 Ergon Energy, email to the AER, Q.AER.ERG.27.01, 20 October 2009 confidential.

occurred around this time, where some costs that were once grouped as part of a shared cost pool were transferred to opex costs. The AER considers these variations to base year opex provide a reasonable justification for the base year opex overspend.

Benchmarking

The AER also undertook benchmarking, which are discussed in detail in appendix J of this draft decision. This benchmarking included ratio analysis and regression analysis of measures of Ergon Energy's 2007–08 opex against other Australian DNSPs. The AER provided its ratio analysis to PB, who considered the results and concluded that Ergon Energy's opex forecasts were relatively high when compared to the other businesses. However, PB noted several differences in Ergon Energy's business approach and operating environment that may account for the apparent higher costs.[491]

The AER' regression analysis compares 2007–08 data of rural DNSPs in Australia. Consistent with the ratio analysis undertaken by the AER, and the Benchmark Economics work, the AER's regression modelling shows that Ergon Energy lies above the regression line, indicating it has relatively high opex in 2007–08, in comparison to other rural DNSPs in the sample.

Overall the AER considers the base year opex to be efficient as it reflects the efficient allowance provided by the QCA, and the overspend has been justified by Ergon Energy. The AER also notes that the 2007–08 data is the most up to date available and has been subject to audit.

While the AER and PB's benchmarking analysis shows that Ergon Energy's 2007–08 opex is relatively higher than other similar businesses, the AER considers this does not detract from its assessment that 2007–08 represents an efficient base year opex for Ergon Energy.

The AER and PB's benchmarking studies are focused on Ergon Energy's operating performance at a systemic level compared with similar businesses. The level of relative efficiency depends on the business approach and operating environment of the business compared with other similar businesses. Results from the AER's benchmarking studies are discussed further in appendix J.

The AER notes that benchmarking is one of only ten factors which the AER must have regard to when assessing the relative efficiency of a DNSP's opex forecasts.[492] The AER therefore considers that, while benchmarking is a useful analytical tool, its use should be limited to a top down test of more detailed bottom up assessments.

Network operations

Ergon Energy proposed a total of $134 million ($2009–10) on network operations in the next regulatory control period.

PB reviewed Ergon Energy's forecast for network operations, including the information provided in the budgeting process, specific key performance indicators

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[491] PB, *Report – Ergon Energy*, October 2009, p. 143.
[492] NER, clause 6.5.6(e)(1)–(10).

and performance targets. PB concluded that Ergon Energy's proposed network operations opex was prudent and efficient.[493]

The AER notes Ergon Energy's network operations forecast has assumed a business as usual scenario for network operations, and likely increases in workload are absorbed through efficiency gains resulting from the implementation of Project LINK. The AER also notes PB's conclusion that the forecast expenditure was efficient and prudent. The AER considers Ergon Energy has appropriately modelled its network operations expenditures.

Network maintenance

Preventative maintenance (excluding vegetation management)

Ergon Energy forecast $594 million ($2009–10) on preventative maintenance in the next regulatory control period. Ergon Energy stated that its preventative maintenance opex forecast is based on an assessment of the historical performance of its assets, the age and condition of its assets and other factors.[494]

PB noted that Ergon Energy proposed an average (real) increase of 47 per cent in its preventative maintenance opex, compared to the current regulatory control period.[495] PB noted that the inspection and maintenance programs were based on qualified risk assessments for each of the asset classes and concluded the programs were reasonable and pragmatic, balancing costs against safety and compliance requirements.[496] However PB noted two exceptions to its general conclusion regarding pole assets and visual inspections.

The AER considers that Ergon Energy's bottom up approach to developing preventative maintenance forecasts is an appropriate model that takes into account risk analysis, cost data and relevant policies.

However, the AER considers that Ergon Energy has been overly conservative in its approach to risk regarding the possible failure of its wooden poles. The AER considers that given the current reliability of the poles, and Ergon Energy's comprehensive knowledge of the assets arising from the previous inspection cycle, increasing the inspection cycle to 4.5 years will result in opex forecasts that better reflect the costs of a prudent operator.

The AER considers the overhead services inspection program is appropriate but overlaps with the coincident visual inspections program. As the two programs achieve similar outcomes, the AER considers Ergon Energy should take into account a reduction in the number of coincident visual inspections, to offset the increase in full inspections, after its pilot program is completed in 2009–10.

The AER notes Ergon Energy included an escalation to account for network growth in its preventative maintenance modelling. The AER considers the reduction in network

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[493] PB, *Report – Ergon Energy*, October 2009, pp. 120–121.
[494] Ergon Energy, *Preventative Maintenance Programs for 2010/11–2014/15,* May 2009, p. 12, confidential.
[495] PB, *Report – Ergon Energy*, October 2009, p. 145.
[496] PB, *Report – Ergon Energy*, October 2009, p. 123.

growth discussed in chapter 7 of this draft decision must be incorporated into the opex forecasts.

The AER requested Ergon Energy remodel its non vegetation preventative maintenance opex forecast to take into account the longer inspection cycle for ground based poles, to reduce the number of coincident visual inspections, to incorporate the capex/opex trade off and account for the reduction in network growth and to incorporate the capex/opex trade off associated with the significant increase in replacement capex.[497]

These adjustments resulted in a reduction to preventative maintenance of $33 million ($2009–10).[498]

Corrective maintenance (excluding vegetation management and access track costs)

Ergon Energy proposed to spend $590 million ($2009–10) on corrective maintenance activities over the next regulatory control period. Ergon Energy stated that 27 per cent ($160 million) of corrective maintenance opex relates to corrective works conducted on network assets in order to minimise condition–based and age–related defects.[499] It stated that the defects would be identified when carrying out its proposed preventative maintenance activities.[500]

PB reviewed Ergon Energy's forecast methodology and proposed scope changes. PB considered the forecasting approach was reasonable, and found that the forecasts were aligned with Ergon Energy's business strategy. PB stated, with the exception of dismantling old lines, the scope changes proposed by Ergon Energy were reasonable and justified.[501] PB stated that the dismantling of old lines program reflected capital works, and considered this cost would be capitalised as part of project costs,[502] therefore including this cost would result in a double count of these expenditures.

The AER has reviewed the information provided by Ergon Energy and PB regarding scope changes that impact on the volume of corrective maintenance work. With respect to the removal of old lines, the AER does not consider it appropriate to make a scope change to base year opex for this work program.

The AER requested Ergon Energy to remodel its non vegetation corrective maintenance opex forecast to exclude the old lines removal scope change estimate and incorporate the capex/opex trade off associated with the significant replacement capex program. These adjustments resulted in a reduction to non vegetation corrective maintenance of $14 million ($2009–10).[503]

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497 AER, modelling request, 6 November 2009.
498 Ergon Energy, modelling response PL869c, 13 November 2009, confidential.
499 Ergon Energy, *Regulatory proposal*, July 2009, p. 272.
500 Ergon Energy, *Regulatory proposal*, July 2009, p. 272.
501 PB, *Report – Ergon Energy*, October 2009, p. 126.
502 PB, *Report – Ergon Energy*, October 2009, p. 126.
503 Ergon Energy, modelling response PL869c, 13 November 2009, confidential.

Forced maintenance

Ergon Energy proposed forced maintenance costs of $206 million ($2009–10) in the next regulatory control period.[504] Ergon Energy stated that the volume and costs associated with forced maintenance activities cannot be accurately forecast due to the reactive nature of forced maintenance activities. Instead, an annual provision was made using a hybrid bottom up and baseline/scope change approach.

PB considered that Ergon Energy's proposed asset replacement and corrective maintenance expenditure programs, if approved and then implemented, should reduce the need for forced maintenance expenditure.[505] PB recommended a reduction in forced maintenance opex of $6.7 million in the next regulatory control period to account for these efficiencies.[506]

The AER has concerns regarding the interaction between forced maintenance and corrective and preventative maintenance activities. Ergon Energy has not explicitly accounted for the likely improvement in the performance of network assets as a result of increased spending in other opex and capex programs. Ergon Energy's corrective and preventative maintenance programs, and replacement capex program should all contribute to a reduction in forced maintenance due to poor condition or performance of assets. On this basis the AER considers that a reduction in forced maintenance activity should be achievable in the next regulatory control period.

The AER requested Ergon Energy to remodel its forced maintenance opex forecast to reduce the estimated activity. Ergon Energy advised these adjustments resulted in a reduction to forced maintenance of $6.7 million.[507]

Vegetation, access tracks maintenance

Ergon Energy proposed an opex allowance of $549 million ($2009–10) for vegetation management, and maintenance of access corridors and sites in the next regulatory control period. Ergon Energy stated that an increased opex allowance for vegetation and access track and sites management activities was needed to clear a rural backlog and to comply with regulatory obligations.

PB stated that the Ergon Energy provided clear evidence of the need to clear rural backlog work and the need to comply with clearance regulatory standards.[508] PB also stated that Ergon Energy provided clear evidence of the need for a significant change in its approach to vegetation management. PB found Ergon Energy's proposed vegetation management opex to be prudent and efficient, with the exception of an unexplained increase in historical costs, the application of a cumulative growth factor, no explicit modelling of economies of scale or interactions with other corrective and preventative maintenance programs, and the number of new keys and locks on access track gates being installed.[509] As a result of the identified issues, PB recommended a

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504 Ergon Energy, *Regulatory proposal*, July 2009, p. 276; and Ergon Energy, *Qld Public forum presentation slides,* 3 August 2009.
505 PB, *Report – Ergon Energy*, October 2009, pp. 128–129.
506 PB, *Report – Ergon Energy*, October 2009, p. 130.
507 Ergon Energy, modelling response PL869c, 13 November 2009, confidential.
508 PB, *Report – Ergon Energy*, October 2009, p. 146.
509 PB, *Report – Ergon Energy*, October 2009, p. 132–134.

total reduction of $48 million in relation to Ergon Energy's vegetation management and access tracks and sites opex.[510]

The AER accepts that increased vegetation management and access tracks work needs to be carried out in the next regulatory control period. It also accepts the methodology used by Ergon Energy to calculate the unit cost rates. However the AER was not satisfied with the information provided by Ergon Energy with respect to those elements of concern identified by PB.

The AER requested that Ergon Energy remodel its vegetation and access tracks and sites opex forecast with the following amendments:[511]

- removal of cumulative growth factors from opex forecasts in relation to management of endangered species (80 per cent), declared plants (40 per cent) and cultural heritage (100 per cent)
- incorporation of the expected reduction in corrective maintenance by reducing the work volume increase from 100 per cent to 30 per cent
- a reduction in the number of locks and keys to be installed to 24 000.

The AER notes that Ergon Energy did not incorporate an adjustment to remove a 5 per cent unit cost increase, due to an error in the modelling request from the AER. The AER has incorporated PB's recommended adjustment of $12 million to corrective maintenance to account for this amendment.

These adjustments resulted in a reduction to vegetation management opex of $53 million ($2009–10).[512]

Other operating costs

Ergon Energy proposed to spend $375 million ($2009–10) on other operating costs in the next regulatory control period including $101 million on customer service activities and $60 million on meter reading.

PB found that there was an overlap of key activities of standard and alternative control services in relation to metering and customer care activities. Accordingly, PB recommended a reduction of $80 million during the next regulatory control period resulting from the inclusion of alternative control services activities in the standard control service customer services forecasts.[513]

The AER has not been able to verify that alternative control service costs have not been incorporated into Ergon Energy's modelling of other operating costs for standard control services. Accordingly, the AER considers that the metering and customer care opex forecast should be amended to remove alternative control services costs.

510 PB, *Report – Ergon Energy*, October 2009, p. 134.
511 AER, modelling request, 6 November 2009.
512 Ergon Energy, modelling response PL869c, 13 November 2009, confidential.
513 PB, *Report – Ergon Energy*, October 2009, p. 146.

The AER accepts Ergon Energy's forecast of GSL payments as efficient as the forecast is consistent with its historical levels of GSL payments and has been updated (in real terms) where relevant to reflect revised payments schedules.

The AER accepts Ergon Energy's proposed expenditure forecast on training activities on the basis that PB's review found that training costs are aligned with historical costs, that no increase is expected to occur in the next regulatory control period and that efficiencies can be achieved by training staff in multiple areas.

The AER notes that a $1 million per annum forecast for the demand management innovation allowance (DMIA) is incorporated into other opex forecasts, based on the notional amount provided for Ergon Energy in the framework and approach paper.[514] Chapter 14 of this draft decision discusses the DMIA in greater detail.

The AER considers that Ergon Energy has not demonstrated how its forecast sponsorship proposal is required to achieve the opex objectives, nor has it outlined how it is relevant to the provision of standard control services. The AER requested Ergon Energy to remodel its other operating cost forecast to remove sponsorship costs.

The AER requested Ergon Energy to remodel its other operating costs forecast to reflect the AER's conclusion regarding metering and customer care, incremental demand management project management costs and sponsorship costs.

These adjustments resulted in a reduction to other operating costs of $84 million ($2009–10).[515]

Demand management program

Ergon Energy proposed to spend $61 million ($2009–10) in the next regulatory control period in opex relating to its non–network alternative program. Ergon Energy's demand management program consists of a number of broad based programs that defer network augmentation projects identified through the regulatory test process.

PB reviewed Ergon Energy's demand management proposal in detail. PB found that the various new trials were generally well targeted and provided a pragmatic approach to increasing awareness and opportunities for demand side activity. However, PB recommended a reduction of $2.6 million in relation to project management costs in the next regulatory control period.

The AER reviewed the costing proposals associated with Ergon Energy's demand management initiatives. The AER considers that the proposed demand management initiatives are prudent, with the exception that economies of scale and productivity improvements should be factored into the programs proposed project management costs.

514 AER, *Final framework and approach paper – Energex and Ergon Energy 2010–15 application of schemes,* November 2008.

515 Ergon Energy, modelling response PL869c, 13 November 2009, confidential.

The AER requested Ergon Energy to remodel its demand management forecast to incorporate economies of scale and productivity improvements.[516] The adjustments resulted in a reduction to demand management forecasts of $2.8 million ($2009–10).[517]

Self insurance

Ergon Energy's self insurance proposal is discussed in section 8.8.5.1 of this chapter.

Shared costs – ICT costs

Ergon Energy's ICT shared costs are allocated across Ergon Energy's capex and opex programs in accordance with its CAM. Ergon Energy's shared costs are discussed in detail in section G.5.5 of this draft decision.

As a result of the reasons discussed in section G.5.5, the AER is not satisfied that the proposed ICT costs reflect the opex criteria, including the opex objectives. As a result, the AER considers that a reduction of $6.4 million ($2009–10) to Ergon Energy's opex is necessary.

Superannuation

The AER notes that Ergon Energy included superannuation costs within its opex forecasts as labour on–costs. The AER has examined the financial statements of Ergon Energy[518] and accepts that obligations and payments in relation to defined benefit superannuation schemes are imposed by the *Occupational Superannuation Standards Regulations 1987*.[519]

The level of payments to be made by Ergon Energy in respect of defined benefits superannuation schemes have increased due to the volatility within financial markets over the past two years. However, the AER considers that as financial markets stabilise, Ergon Energy's financial obligations in respect of defined benefit superannuation schemes will decline. The AER expects any updated information regarding the financial obligations of Ergon Energy in respect to defined benefit superannuation schemes to be reflected in its revised regulatory proposal. The AER also notes that a significant revision to such financial obligations may constitute negative pass through events in the next regulatory control period.

8.8.4 AER conclusion – Ergon Energy controllable opex

Table 8.8 sets out the AER's adjustments to Ergon Energy's forecast controllable opex. These adjustments are derived from Ergon Energy's opex model and reflect the AER's conclusion on an efficient controllable opex. The adjustments do not include the impact of the AER's revised input cost escalators.

516 AER, modelling request, 6 November 2009.
517 Ergon Energy, modelling response PL869c, 13 November 2009 confidential.
518 Ergon Energy, *Governance and Annual Financial Report*, 2008–09.
519 Occupational Superannuation Standards Regulation 1987, clause 18Y. Accessed from Australian Legal Information Institute, http://www.austlii.edu.au/au/legis/cth/consol_reg/ossr513/.

Table 8.8: AER adjustment to Ergon Energy's controllable opex, excluding input escalation ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy's proposed controllable opex[a]	365.9	377.3	381.2	382.3	370.2	1876.9
Adjustment to preventative maintenance	–4.3	–5.5	–6.7	–7.8	–8.6	–32.9
Adjustment to corrective maintenance	–2.2	–2.7	–3.1	–3.3	–3.1	–14.4
Adjustment to forced maintenance	–0.0	–0.4	–1.2	–2.0	–3.0	–6.7
Adjustment to vegetation management	–9.9	–10.5	–11.1	–11.5	–9.6	–52.6
Adjustment to other opex	–16.1	–16.2	–16.5	–17.2	–17.6	–83.6
Adjustment to ICT shared costs	–0.2	–0.9	–1.7	–1.8	–1.9	–6.4
Total adjustments	–32.7	–36.2	–40.3	–43.5	–43.9	–196.6
AER adjusted controllable opex allowance[b]	333.2	341.1	340.9	338.8	326.3	1680.3

Note: Totals may not add due to rounding.

a Ergon Energy's controllable opex does not include proposed self insurance costs of $25.1 million or proposed debt and equity raising costs of ($94.1 million).

b The AER's adjusted controllable opex does not include the application of the AER's revised input cost escalators. The application of the AER's revised input cost escalators are discussed in chapter 8 of this draft decision.

8.8.5 Uncontrollable opex

8.8.5.1 Self insurance

Qld DNSP proposals

The Qld DNSPs proposed forecast allowances for self insurance premiums for the next regulatory control period. The Qld DNSPs did not have self insurance in the current regulatory control period.

Energex engaged Finity Consulting Pty Ltd (Finity) to provide actuarial assessments of its self insurance costs. Ergon Energy engaged Synergies Economic Consulting (Synergies), in partnership with Finity, to assist in preparing its self insurance proposal.[520] The Qld DNSPs also provided board resolutions confirming endorsement to self insure against the risks identified in their regulatory proposals.[521]

The Qld DNSPs' proposed allowances for self insurance premiums for the next regulatory control period are shown in table 8.9.

Table 8.9: Qld DNSPs proposed self insurance premiums for the next regulatory control period ($m, 2009–10)

Risk	Energex	Ergon Energy
Property damage (storm catastrophe)	8.4	5.3
Public liability (large losses/claims)	6.3	4.0
Public liability (attritional)	–	11.7
Public liability (bushfire)	–	0.6
Retailer credit risk	0.4	–
Total proposed self insurance	15.1	21.5

Source: Energex, *Regulatory proposal*, July 2009, p. 172; and Ergon Energy, email response, 19 November 2009, confidential.
Note: Totals may not add due to rounding.

AER considerations

The AER's detailed considerations of the Qld DNSPs' proposed self insurance allowances are set out in appendix K. In summary, the AER does not consider that the proposed self insurance allowances are prudent and efficient.

In forming this view the AER considered each proposed premium against five key assessment criteria. The AER considers that these criteria are relevant to the opex objectives and criteria outlined in section 6.5.6 of the NER.

The AER also notes that the Qld DNSPs have applied real input cost escalators to their self insurance premium forecasts. As discussed in appendix H, the AER considers that the escalators applied by the Qld DNSPs do not reflect the efficient cost of inputs required to meet the opex criteria, including the opex objectives.

The AER requested the Qld DNSPs to remodel their self insurance premium forecasts to reflect the AER's adjustments set out in appendix K and the revised cost escalators specified in appendix H.

[520] Finity, *Review of Self Insurance Program: Energex Limited*, May 2009, confidential; and Finity, *Review of Self Insurance Program: Ergon Energy*, March 2009, confidential.

[521] Energex, *Board memorandum 23/02/2009*, confidential; and Ergon Energy, *Minutes of the board meeting 27/03/2009*, confidential.

AER conclusion

As a result of its analysis of the information provided by the Qld DNSPs, the AER is not satisfied that the proposed self insurance allowances reasonably reflect the opex criteria, including the opex objectives.

The AER considers that making a $15.1 million reduction to Energex's forecast and a $21.5 million reduction to Ergon Energy's forecast are likely to result in self insurance expenditures that reasonably reflect the opex criteria, including the opex objectives, and are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors and the self insurance principles outlined in appendix K.

Table 8.10 summarises the proposed self insurance allowances and the AER's draft decision.

Table 8.10: AER conclusion on self insurance allowances ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed	2.800	2.900	3.100	3.200	3.000	15.100
AER adjustments	–2.792	–2.892	–3.092	–3.192	–2.992	–15.060
Total self insurance	0.008	0.008	0.008	0.008	0.008	0.040
Ergon Energy proposed	4.152	4.162	4.279	4.379	4.515	21.504
AER adjustments	–4.149	–4.159	–4.276	–4.393	–4.512	–21.488
Total self insurance	0.003	0.003	0.003	0.003	0.003	0.016

Note: Totals may not add due to rounding.

8.8.5.2 Debt raising costs

Debt raising costs are costs which are incurred each time debt is raised or refinanced. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has previously accepted that debt raising costs may be a legitimate expense for which a DNSP should be provided an allowance.[522]

Qld DNSPs regulatory proposals

The Qld DNSPs proposed that the cost of raising debt finance be benchmarked as an annual cost per dollar of allowed debt associated with their regulatory asset bases (RAB)—that is, the benchmark gearing ratio multiplied by the RAB. Both Qld DNSPs proposed an allowance of 15.5 basis points per annum (bppa), comprising:

- 12.5 bppa for direct debt raising costs

[522] AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 94–97; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, pp. 148–150; and AER, *Final decision, ElectraNet transmission determination 2008–09 to 2013–14*, 11 April 2008, pp. 84–85.

- 3.0 bppa for indirect debt raising costs.

In support of their regulatory proposals, the Qld DNSPs submitted a jointly commissioned report prepared by Synergies.[523] The Qld DNSPs' notional proposed debt raising costs are set out in table 8.11.

Table 8.11: Qld DNSPs proposed notional debt raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	7.2	8.1	9.0	9.9	10.7	44.8
Ergon Energy	11.9	16.3	22.0	22.8	21.1	94.1

Source: Energex, *Regulatory proposal*, July 2009, p. 173; and Ergon Energy, *Regulatory proposal*, July 2009, p. 306.

Note: Ergon Energy's proposed debt raising costs of $94.1 million does not reconcile with Ergon Energy's revenue modelling. Ergon Energy included an amount of $94.1 million for both equity and debt raising costs by inputting an incorrect allowance for debt raising costs.

Submissions

The EUAA stated that the debt raising costs proposed by Energex appear unreasonable. It noted that, as Energex is owned by the Queensland Government, which arranges Energex's debt, there should be no costs allowed for this cost category. The EUAA stated the AER should not allow any expenditure in this area unless there is clear demonstration that benefits will exceed costs.[524]

AER considerations

The AER's detailed analysis and considerations of the Qld DNSPs' proposed debt raising costs are set out in appendix L. In summary, the AER considers that:

- the Qld DNSPs have not presented any new evidence to support the inclusion of indirect debt raising costs
- the actual ownership status of the Qld DNSPs is not relevant under clause 6.5.6(c) of the NER, which requires opex to be set with regard to the benchmark efficient entity
- the proposed alternative methodologies for estimating direct debt raising costs do not closely match the circumstances of the benchmark firm.

The AER will continue to apply an approach based on the Allen Consulting Group (ACG) methodology as it considers this produces the best estimate possible. The AER has refined this methodology by:

- updating its selection of bonds from the Bloomberg data service to fully align with the ACG criteria

[523] Synergies, *Debt and equity raising costs: Report for Energex and Ergon Energy*, May 2009. Submitted as attachment 12.5 to the Energex regulatory proposal and attachment 534c to the Ergon Energy regulatory proposal.

[524] EUAA, *Submission to the AER*, August 2009, p. 20.

- accounting for the time value of money, including amortisation of up front costs and indexation of fixed costs as appropriate

- updating the benchmark medium term note (MTN) issue size with the latest available data.

The direct debt raising cost allowance for each of the Qld DNSPs will be dependent on the number of standard sized debt issues required by each business (based on the debt value of the RAB), and the nominal vanilla WACC applying to each business (to be incorporated in the amortisation calculation). Table 8.12 shows the AER's indicative debt raising cost allowance based on a nominal vanilla WACC of 10.06 per cent.

Table 8.12: Indicative direct debt raising costs with a nominal vanilla WACC of 10.06 per cent

Fee	Explanation	1 Issue	3 Issues	7 Issues	17 Issues	18 Issues
Amount Raised	Multiples of median MTN ($263m)	$263 million	$789 million	$1 841 million	$4 471 million	$4 734 million
Gross underwriting fee	Median gross underwriting spread, up front per issue	7.34	7.34	7.34	7.34	7.34
Legal and roadshow	$115K upfront per issue	0.71	0.71	0.71	0.71	0.71
Company credit rating	$50K per annum	1.90	0.63	0.27	0.11	0.11
Issue credit rating	4 basis points up front per issue	0.65	0.65	0.65	0.65	0.65
Registry fees	$3.5K up front per issue	0.13	0.13	0.13	0.13	0.13
Paying fees	$4/$1million per annum	0.01	0.01	0.01	0.01	0.01
Total	Basis points per annum	10.7	9.5	9.1	9.0	9.0
Previous value (2008 update)	Number of $200m issues	1 issue	4 issues	9 issues	22 issues	24 issues
	Basis points per annum	10.4	8.5	8.1	8.0	8.0

Source: ACG, Bloomberg, AER analysis.

Energex has an opening RAB of $7.9 billion. On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of Energex's opening RAB is around $4.7 billion. Based on the ACG methodology, this debt size would require around 18 bond issues. The nominal vanilla WACC for Energex is 10.06 per cent. As such, the AER considers that an allowance of 9.0 bppa for debt raising costs is a reasonable benchmark for Energex. Using the post–tax revenue model (PTRM), this benchmark is multiplied by the debt component of Energex's opening RAB to derive an average allowance of $5.1 million per annum ($2009–10).

Ergon Energy has an opening RAB of $7.1 billion. On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of Ergon Energy's opening RAB is around $4.3 billion. Based on the ACG methodology, this debt size would require around 17 bond issues. The nominal vanilla WACC for Ergon Energy is 10.06 per cent. As such, the AER considers that an allowance of 9.0 bppa for debt raising costs is a reasonable benchmark for Ergon Energy. Using the PTRM, this benchmark is multiplied by the debt component of Ergon Energy's opening RAB to derive an average allowance of $4.4 million per annum ($2009–10).

AER conclusion

As a result of its analysis of the information provided by the Qld DNSPs, the AER is not satisfied that the proposed benchmark debt raising costs reasonably reflect the opex criteria, including the opex objectives.

The AER considers that making a $20 million reduction to Energex's proposed allowance and a $72 million reduction to Ergon Energy's proposed allowance is likely to result in forecast debt raising costs that reasonably reflect the opex criteria, including the opex objectives, and are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

Table 8.13 sets out the AER's draft decision on forecast debt raising costs for the Qld DNSPs.

Table 8.13: AER conclusion on Qld DNSP's debt raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	4.2	4.6	5.1	5.5	6.0	25.3
Ergon Energy	3.7	4.0	4.4	4.7	5.1	22.0

8.8.5.3 Equity raising costs

In raising new equity capital a business may incur costs such as legal fees, brokerage fees, marketing costs and other transactions costs. These are upfront expenses, with little or no ongoing costs over the life of the equity. While the majority of the equity a firm will raise is typically obtained at its inception, there may be points in the life of a firm—for example, during capital expansions—where it chooses additional external equity funding (instead of debt or internal funding) as a source of equity capital, and accordingly may incur equity raising costs.

The AER has previously accepted that equity raising costs are a legitimate cost for a benchmark efficient firm only where external equity funding is the least–cost option available.[525] A DNSP should only be provided an allowance for equity raising costs where cheaper sources of funding—for example, retained earnings—are insufficient,

[525] AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–2012*, 14 June 2007, p. 100; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013– 14*, January 2008, p. 144; AER, *Final decision, ElectraNet transmission determination 2008–09 to 2013–14*, 11 April 2008, p. 88.

subject to the gearing ratio and other assumptions about financing decisions being consistent with regulatory benchmarks.

Qld DNSPs regulatory proposals

As a basis for their regulatory proposals on this issue, the Qld DNSPs submitted a jointly commissioned report prepared by Synergies.[526]

Energex did not detail the methodology it used to generate an estimate of equity raising costs, instead referencing the Synergies report.[527] Energex stated that it requires $1030 million in external equity during the next regulatory control period, and its proposed equity raising allowance is set out in table 8.14.

Table 8.14: Energex proposed benchmark equity raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Equity raising cost	20.6	19.8	18.8	15.7	12.6	87.4

Source: Energex, *Regulatory proposal*, July 2009, section 12.7.6, p. 174.

Ergon Energy proposed a hierarchy of three methods of equity raising, with differing costs and availability:[528]

- First, firms use retained earnings as a source of equity. The amount of equity raised in this manner is dependent on the benchmark cash flow calculations. The cost of this equity raising is set at zero per cent of the equity raised via this method.[529]
- Second, firms use dividend reinvestment plans. The amount of equity raised in this manner is capped at 30 per cent of all outgoing dividends. The cost of this equity raising is set at 2 per cent of the equity raised via this method.[530]
- Third, firms use seasoned equity offerings (SEOs) encompassing both rights issues and placements. The benchmark firm obtains all the remaining equity required via this method and the cost is set at 7.8 per cent of all equity raised. This figure comprises 4.5 per cent for direct equity raising costs, and 3.3 per cent for indirect equity raising costs associated with the SEO.[531]

Ergon Energy did not present a calculation of the total equity raising cost resulting from these per cent costs in its regulatory proposal. However, following a request by the AER, Ergon Energy submitted on 22 October 2009 an equity raising benchmark cash flow model that calculated the proposed external equity raising to be around $1257 million. Ergon Energy proposed that its annual equity raising cost forecast be treated in opex and the break down of this proposed allowance is set out in table 8.15.

526 Synergies, *Debt and equity raising costs*, May 2009.
527 Energex, *Regulatory proposal*, July 2009, p. 174.
528 Ergon Energy, *Regulatory proposal*, July 2009, pp. 306–308.
529 Ergon Energy, *Regulatory proposal*, July 2009, p. 307.
530 Ergon Energy, *Regulatory proposal*, July 2009, p. 307.
531 Ergon Energy, *Regulatory proposal*, July 2009, p. 307.

Table 8.15: Ergon Energy proposed benchmark equity raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Equity raising cost	11.3	16.1	21.9	22.8	21.2	93.2

Source: Ergon Energy, Equity raising costs model, 22 October 2009, Calcs tab.
Note: This amount does not reconcile with Ergon Energy's revenue modelling or its regulatory proposal. Ergon Energy included an amount of $94.1 million for both equity and debt raising costs by inputting an incorrect allowance which is sought for debt raising costs.

Submissions

The EUAA stated that the equity raising costs proposed by Energex seem unreasonable. It noted that as Energex is owned by the Queensland Government, which provides Energex's equity, there should be no costs allowed for this cost category. The EUAA stated the AER should not allow any expenditure in this area unless there is clear demonstration that benefits will exceed costs.[532]

AER considerations

The AER's detailed analysis and considerations of the Qld DNSPs' proposed equity raising costs are set out in appendix M.

In summary, the AER notes that the use of a hierarchy of equity raising types is consistent with the benchmark cash flow analysis implemented previously by the AER.[533] The AER notes Synergies' statements on the observed incidence of equity raising types in the Australian market. Consistent with earlier statements, the AER considers that the benchmark firm is not bound to issue equity in proportions that match the market average.[534] The AER considers that the data on equity raising types categorised by purpose remains the most relevant guide to the types of equity issued by the benchmark firm. Further, the AER observes that the there is greater transparency regarding the data sources and presentation of figures for this analysis than the alternative presented by Synergies.

The AER considers that the proposed allowance for indirect equity raising costs is inconsistent with the regulatory framework (regardless of whether the indirect costs relate to retained earnings, dividend reinvestment programs or SEOs). All underpricing that reflects transaction costs can reasonably be expected to be included in the existing return on equity allowance (under the capital asset pricing model). This allowance is based on market observations in the presence of real world transaction costs, so should be fully inclusive of any compensation required to offset these indirect costs. To the extent that underpricing exists beyond this level, it still does not reflect a cost to the shareholders in aggregate (as opposed to being a cost to certain individual shareholders).

The AER considers that the proposed allowance for direct equity raising costs for dividend reinvestment plans should be based on the most reliable and relevant data

532 EUAA, *Submission to the AER*, August 2009, p. 20.
533 AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 194 (table 8.18), 579–587.
534 AER, *Final decision, ACT DNSP*, April 2009, appendix H, p. 241.

available. The AER considers that its updated data set produces the best estimate, given that it:

- is based on recent Australian data
- is based on a reasonable sample size
- does not include inappropriately categorised equity raisings
- correctly accounts for underwriting costs where only a portion of the issue is underwritten
- is more transparent than any of the alternative data sets put forward.

This results in a benchmark direct cost of raising equity through dividend reinvestment plans of 1 per cent of the equity raised in this manner.

The proposed allowance for direct equity raising costs of SEOs should be based on consideration of data from recent Australian seasoned equity issues. Accordingly, the AER considers that the Synergies benchmark, which includes both US data and initial public offerings, is a poor proxy for an external equity raising undertaken by the benchmark firm. The AER updates its previous analysis of direct equity raising costs by Australian companies, which results in the benchmark allowance being 3.0 per cent of the external equity raised through SEOs.

These benchmark unit costs are applied in the context of the cash flow analysis to determine the amount of equity required, the availability of retained earnings, the amount of dividends reinvested and the final requirement for external equity.[535]

The AER's conclusion on benchmark equity raising costs for the Qld DNSPs over the next regulatory control period is set out in table 8.16.

[535] See AER, *Final decision*, NSW DNSPs, April 2009, p. 194.

Table 8.16: AER conclusion on benchmark equity raising cost ($m, nominal)

Cash flow analysis	Energex	Ergon Energy	Notes
Dividends	1291.1	758.7	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	387.3	227.6	30% of dividends paid
Cost of dividend reinvestment plans	3.9	2.3	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	5642.1	4737.6	This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment)
Debt component	3229.3	2506.6	Set to equal 60% of RAB increase (not capex)
Equity component	2412.9	2231.0	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	1177.1	1870.6	Includes dividends reinvested
External equity requirement	1235.8	360.4	Equal to equity component less retained cash flows
External equity raising cost	37.1	10.8	External equity requirement multiplied by benchmark direct cost (3%)
Total equity raising cost	41.0	13.1	Sum of dividend reinvestment plan cost and external equity raising cost
Total equity raising cost ($2009–10)	36.8	11.9	To be added to the RAB at the start of the next regulatory control period

The Qld DNSPs proposed to include equity raising costs as part of their forecast opex allowances.[536] Energex took the proposed equity raising cost allowance and included it as a per annum cost in its opex forecast. It appears Ergon Energy used a similar approach although it is not clear because the input values to the PTRM do not reconcile with the amounts calculated in the equity raising cost benchmark cash flow model.

The AER has reviewed the treatment of equity raising costs in the Qld DNSPs' regulatory proposals. While the Qld DNSPs have used the benchmark cash flow analysis (as determined by the AER in its April 2009 regulatory determinations) to model the equity raising cost allowance, two adjustments (other than the unit costs for dividend reinvestment plans and SEOs) are required. These include the imputation payout ratio being changed from 70 to 100 per cent for consistency with the gamma

536 Energex, *Regulatory proposal*, July 2009, p. 174; and Ergon Energy, *Regulatory proposal*, July 2009, p. 308.

assumption set out in chapter 9, and removing the impact of capital contributions on the amount of tax payable in the cash flow analysis.[537]

The AER considers that the Qld DNSPs have misunderstood the need to convert the equity raising cost allowance to an annuity equivalent or perpetuity stream, if the treatment of equity raising cost in opex was to be applied appropriately. As noted in ETSA Utilities' regulatory proposal 'the nature of equity raising [cost] is such that it exists in perpetuity until the assets being funded are realised.' Ergon Energy claimed that the AER's treatment of equity raising costs (amortised over the standard life of the RAB) in its April 2009 regulatory determinations was not superior to treating equity raising cost allowance in opex. Given the incorrect application of equity raising costs in opex by the Qld DNSPs, the AER considers that Ergon Energy's claims about transparency and administrative benefits with such an approach over the amortisation treatment to be invalid.

The AER considers that there is merit in treating the equity raising cost allowance as a part of the Qld DNSPs' RAB—that is, to amortise the allowance. This improves transparency, given that the nature of the allowance is associated with capex, and ensures that future revenue resets for the Qld DNSPs would be administratively simpler in the provision of such an allowance.

Further, the AER notes that treating the equity raising cost allowance in perpetuity or in the RAB would be NPV neutral. In the 2004 ACG report it was recommended that equity raising costs be added to the RAB and amortised along with other assets:[538]

> If the regulator has determined that an allowance for the SEO [seasoned equity offering] cost of raising equity for ongoing capital expenditure should be provided for, we recommend that this amount be added to the RAV [regulatory asset value] (i.e. included as part of the capital expenditure cost) and depreciated over the life of the relevant assets.

AER conclusions

For the reasons discussed and as a result of the AER's analysis of the Qld DNSPs' regulatory proposals, the AER is not satisfied that the Qld DNSPs' proposed equity raising cost allowance reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. The AER considers the revised benchmark equity raising cost allowances associated with the Qld DNSPs' forecast capex, as set out in table 8.16 represent the efficient costs that a prudent operator in the circumstances of the Qld DNSPs would require to achieve the opex objectives in the next regulatory control period.

Further, the amounts specified in table 8.16 will be amortised over the life of the Qld DNSPs' RAB for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory control period.[539]

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537 The modelling process for removing the impact of capital contributions has been done to ensure each of the cash flow items are considered on a 'like for like' basis. It would be inappropriate to include the impact of capital contributions in the tax amount because it is not included in each of the other items that are affected such as revenue and the capex requirement.
See AER, *NSW draft distribution determination 2009–10 to 2013–14, Draft decision*, p. 193.

538 ACG, *Debt and equity raising transaction costs: Final report to the ACCC,* December 2004, p. xiii.

8.8.5.4 Interest rate risk hedging costs

Qld DNSPs regulatory proposals

The Qld DNSPs regulatory proposals included statements concerning hedging costs. The Qld DNSPs submitted that it would be prudent for a benchmark efficient network service provider to manage interest rate risk by hedging a portion of that risk on future borrowings. The Qld DNSPs did not include forecast hedging costs in their proposals, stating that there was potential for large market movements between when their proposals were submitted and when the hedging program is likely to be implemented. Both DNSPs stated they would continue to review the costs of a prudent hedging program.[540]

Submissions

The AER received submissions from Energex and Ergon Energy further to their regulatory proposals in relation to hedging costs. The submissions are substantially the same, and are supported by reports from Synergies and Strategic Finance Group Consulting (SFG).[541] A submission was also received from the QTC offering further support to these submissions.[542] The submissions were received at the end of the consultation period with the effect that other interested parties have not had the opportunity to comment on these submissions.

The Qld DNSPs submitted that hedging against interest rate movements is important; that not doing so is likely to expose them to significant costs; and these costs could have other repercussions upon the DNSPs (particularly their ability to maintain credit ratings). They proposed that the AER include compensation specifically for hedging costs within their opex allowances, as the current regulatory framework does not effectively compensate for these costs.[543]

The premise submitted by the Qld DNSPs about the need to hedge, is that the size of their capex relative to their respective RAB values (80 percent and 88 percent for Energex and Ergon Energy, respectively) represents a significant exposure for them to interest rate movements. They submitted that the projected borrowings to maintain a gearing level of 60 percent on these large expenditures are material. The QTC's analysis estimates that should interest rates rise by 2 per cent during the first year of the next regulatory control period and then remain constant for the duration of the

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539 For Energex a standard life of 46.0 years for amortisation purposes, consistent with Energex's weighted average asset life, has been assumed. For Ergon Energy a standard life of 47.8 years for amortisation purposes, consistent with Ergon Energy's weighted average asset life, has been assumed.

540 Energex, *Regulatory proposal*, July 2009, p. 173; and Ergon Energy, *Regulatory proposal*, July 2009, p. 306.

541 The submissions only vary with regard to the indicative costs of hedging as these are based on the size of each DNSP's RAB values. The SFG and Synergies reports are the same for the two DNSPs.

542 Ergon Energy, *Submission to the AER*, August 2009; Energex, *Submission to the AER*, August 2009; QTC, *Submission to the AER*, August 2009. QTC administers the borrowing requirements of the Qld DNSPs.

543 Energex, *Submission to the AER*, August 2009, pp. 2–3; and Ergon Energy, *Submission to the AER*, August 2009, pp. 2–3.

period, the total interest costs would be $69 million and $88 million for Energex and Ergon Energy respectively.[544]

SFG analysed the potential impact of interest rate increases upon credit rating metrics for the Qld DNSPs. The scenario tested was a 2 per cent increase in year two of the next regulatory control period, and then an annual decline of 0.5 per cent back towards the original year one interest rate. SFG submitted that, if unhedged, the interest rate impact would result in key financial ratios (Funds from Operations/Total Debt and Funds from Operations/Interest Expense) being below the benchmark level and could trigger a credit rating downgrade.[545]

The Qld DNSPs submitted that hedging against such potential impacts is efficient and prudent, as the benefits (that is, the avoided costs) would outweigh the costs of hedging. As such, it was proposed that the AER allow compensation specifically for interest rate hedging costs, to be undertaken in the same way that a benchmark allowance for debt and equity raising costs is provided in the opex. Analysis submitted by the QTC estimated indicative costs of hedging based on current forward rates and hedging 100 per cent of the exposure (which is not proposed) to be approximately $34 million and $43 million for Energex and Ergon Energy respectively (in present value terms).[546]

The Qld DNSPs did not propose specific compensation amounts for hedging costs, or information on the specific hedging instruments that would be used if they were compensated for hedging costs. The Qld DNSPs identified some assumptions upon which a method of determining a cost might be developed, seeking to consult with the AER and stakeholders on this matter.[547]

The Qld DNSPs stated the process would commence with the development of a benchmark hedging strategy.[548] The strategy would be customised to the DNSPs by identifying one that would preserve the assumed notional credit rating of BBB+ under a range of interest rate scenarios and applied to the projected borrowings set out in the regulatory proposals. It was further submitted that this could be linked to thresholds for key credit metrics that influence this rating (assuming 60 per cent gearing is maintained). The Qld DNSPs submitted there was no single optimal hedging profile that would achieve this and they did not want the AER to be prescriptive.[549]

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544 Energex, *Submission to the AER*, August 2009, p. 2; and Ergon Energy, *Submission to the AER*, August 2009, p. 2.
545 Energex, *Submission to the AER*, August 2009, p. 2; and Ergon Energy, *Submission to the AER*, August 2009, p. 2.
546 Energex, *Submission to the AER*, August 2009, pp. 2–3; and Ergon Energy, *Submission to the AER*, August 2009, pp. 2–3.
547 Energex, *Submission to the AER*, August 2009, pp. 2–3; and Ergon Energy, *Submission to the AER*, August 2009, pp. 2–3.
548 Energex, *Submission to the AER*, August 2009, p 3; and Ergon Energy, *Submission to the AER*, August 2009, p. 3.
549 Synergies, *Report prepared for Energex and Ergon Energy's submission to the AER*, August 2009, p. 35.

The Qld DNSPs proposed the costs would be based on prevailing market rates and estimated over the same averaging period used to set the risk–free rate and debt risk premium.[550]

The Qld DNSPs submitted that hedging cost compensation is appropriate as it would be based on efficient benchmark costs of reducing exposure, which if not hedged could have more material and adverse impacts. They submitted that effective compensation is not currently provided for in their revenue allowances, giving the following reasons:[551]

- the risk is not compensated via the equity beta because the firms in the AER's comparator sample had capex programs of lower magnitude, and the materiality of the exposures faced by the Qld DNSPs in the next regulatory control period is likely to exceed any reasonable level of compensation that the beta might be assumed to provide

- given the magnitude of the exposures and current market rates, it cannot be assumed that there is sufficient compensation in the term structure of the interest rates.

AER considerations

The Qld DNSPs proposed that compensation be provided for interest rate hedging costs, and that these be included in their opex allowance and be estimated over the same averaging period used to set the risk–free rate. The AER has considered the appropriate categorisation of these claims and their possible merits.

Legal issues

The AER has identified a number of concerns if interest rate hedging costs were categorised as opex. For an item to be included in forecast opex, a DNSP must propose this in its building block proposal and provide sufficient information for the AER's assessment, consistent with clauses 6.5.6(a)–(b) and S6.1.2 of the NER. If the AER does not approve the forecast opex amount, the AER can substitute an amount. The substitute amount must be determined on the basis of the current proposal and amended only to the extent necessary to enable the amount to be approved in accordance with the NER.[552]

The AER notes that the Qld DNSPs have not proposed a forecast amount for interest rate hedging costs, nor a sufficiently concrete method upon which a forecast opex could be determined. As such, in this draft decision the AER has assessed the DNSPs' proposed opex on the basis that costs for interest rate hedging are not included in the proposed forecast opex.

Further, if hedging cost compensation was included in a DNSP's opex allowance, it would appear problematic for it to be estimated over the same averaging period that is

550 Energex, *Submission to the AER*, August 2009, pp. 2–3; and Ergon Energy, *Submission to the AER*, August 2009, pp. 2–3.
551 Energex, *Submission to the AER*, August 2009, pp. 2–3; and Ergon Energy, *Submission to the AER*, August 2009, pp. 2–3.
552 NER, clause 6.12.3(f).

used to set the risk–free rate and debt risk premium, as proposed by the Qld DNSPs. The NER appears to require that opex be based on forecasts for the relevant regulatory control period, not that previous to it.

Categorisation of the claims as opex

The AER notes that any allowance for the risk of higher interest rates on future borrowings must either be a risk premium allowance for risk currently being borne by equity providers and/or an allowance for higher expected costs (required return) on debt in the future. As such, the claims for hedging costs are actually a risk premium related to an investment in either equity capital and/or debt capital. The AER considers that the claims for interest rate hedging costs should be categorised not as opex but rather as a claim for a higher cost of capital.

Further, the AER considers that these claims are distinct from the allowance for benchmark debt and equity raising costs which are included in the opex forecast and amortised respectively. The claims in this instance are distinct as they refer not to the costs of entering into an exchange but rather the costs to transfer risk to another party for the duration of the regulatory control period.

Merits of proposal

In assessing the possible merits of the proposal submitted by the Qld DNSPs, the AER has a number of concerns. These concerns are noted on the basis that the AER considers the claims for interest rate hedging costs to be a cost of capital issue.

The proposal represents a fundamental change to the regulatory framework administered by the AER. In setting the WACC parameters the AER applies a benchmark and not a firm-specific approach. To permit network service providers to argue that a benchmark should not be applied to them when that firm faces a different situation to that benchmark is a fundamental change in approach. The AER does not consider that the Qld DNSPs have demonstrated that their situation requires a departure from the benchmark. The AER notes that in the sample used to determine the benchmark WACC, a firm’s situation might differ from the benchmark in terms of risk, competitive position and true required return. The objective is to set the cost of capital such that the NPV of future investments is equal to zero (that is, such that there is neither over or under investment by regulated businesses). However, the AER sets cost of capital benchmarks conservatively for a number of reasons, including: to achieve an outcome that is consistent with the National Electricity Objective (NEO); to take into account the revenue and pricing principles, the importance of regulatory certainty and the current financial environment.

This conservatism should ensure that in this case, Energex and Ergon Energy will not expect to be undercompensated relative to their true cost of capital on their planned investment over the regulatory control period. For example, in the WACC review, the equity beta was set at 0.80 despite empirical evidence suggesting that its upper bound would be approximately 0.68.[553] Further, a 10 year term of debt was set as a benchmark for determining the cost of debt despite evidence that the term for fair

[553] AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters,* May 2009, p. 244.

compensation would be around 7.4 years.[554] This conservatism is significant and it was explicitly stated in the WACC review that this would offset against claims for hedging costs.[555] Therefore, the AER considers that even if the Qld DNSPs do have a cost of capital that is slightly higher than the typical network service provider and/or the cost of capital (that is, the WACC) does vary across the regulatory control period, the current benchmark should still adequately compensate these firms for the risk borne on their new investment commitments over the next regulatory control period.

The implications for the regulatory framework are of concern, not only from the customisation proposed by the Qld DNSPs but also as they effectively proposed a different cost of capital for each year of the next regulatory control period. The AER notes that clause 6.5.2 of the NER requires the AER to apply a single cost of capital across the regulatory control period. For example, the equity beta and market risk premium parameters are set, as are the methodologies for setting the risk–free rate and cost of debt.

The AER considers that insufficient evidence has been provided by the Qld DNSPs to support their argument that a benchmark firm could not remain unhedged and maintain a BBB+ cost of debt at a 60 per cent debt to 40 per cent equity ratio. The AER has the following concerns:

- the submitted scenario assumption of an unhedged firm appears predicated on the assertion that if not compensated for hedging costs a DNSP will not hedge against interest rates. The AER notes that firms should only hedge when it is wealth maximising, and the decision to make an allowance for hedging (or not) should not affect this decision. The AER considers that not providing explicit compensation for hedging will not create disincentives for firms to hedge against interest rates, where it is rational. As the Qld DNSPs have themselves asserted from the analysis they undertook, the benefits of hedging could significantly outweigh the costs.[556]

- if the scenario submitted by the Qld DNSPs materialised—that is, an increase in the cost of debt by 2 per cent at the end of year one out to the end of the next regulatory control period—the estimated impacts would be $88 million and $69 million for Ergon Energy and Energex respectively. The AER notes that these would be impacts on firms that would have RAB equity values (based on 40 per cent of total RAB) at the start of the next regulatory control period of around $2.8 billion and $3.1 billion respectively. The AER considers that such impacts are unlikely to cause a debt downgrade by the rating agencies. The AER notes that the relatively stable cash flows of regulated businesses (business profile) means that they might be able to maintain a given credit rating with lower cash flow coverage and higher capital structure than most other businesses in the economy.

Not providing an allowance for hedging costs is also appropriate given that it would compensate the DNSPs for risk that equity investors in these firms appear to be

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554 AER, *Final decision, WACC parameters*, May 2009, p. 164.
555 AER, *Final decision, WACC parameters*, May 2009, p. 168.
556 Energex, *Submission to the AER*, August 2009, p. 2; and Ergon Energy, *Submission to the AER*, August 2009, p. 2.

already compensated for, or will not bear. For example, in establishing the RAB the AER applies indexation based on actual out-turn inflation (that is, ex–post) and the allowed revenues are also adjusted for out-turn inflation over each year of the regulatory control period. The AER notes that this effectively eliminates most of the inflation risk facing the owners of DNSPs. Arguably the major component of the normal shape of the term structure of debt is due to an inflation risk premium. Therefore the AER considers that it is inappropriate to further compensate regulated firms for the shape of the term structure where the RAB is indexed ex–post, as to do so is likely to over-compensate equity investors for the actual level of systematic risk they bear under the current regulatory regime. The AER also considers that it would be inappropriate for consumers to pay to eliminate the risk that they will still bear under the current regulatory regime due to RAB indexing and/or because the DNSPs may choose not to hedge regardless of any allowance.

For these reasons and consistent with its decision in the Powerlink transmission determination (June 2007) and in the WACC review, the AER does not approve an allowance for interest rate hedging costs.[557]

AER conclusions

The AER does not agree with the categorisation of the claims for interest rate hedging costs as opex. For the reasons set out in this draft decision, the AER considers this to be a claim for a higher cost of capital.

The AER does not approve of an allowance for interest rate hedging costs for the Qld DNSPs. For the reasons set out in this draft decision, the AER considers that the proposal would represent a fundamental change in the regulatory framework administered by the AER.

The AER considers that insufficient evidence has been provided by the Qld DNSPs to support their claims and have not demonstrated that:

- the AER's cost of capital benchmark is not appropriate for these businesses
- sufficient compensation is not currently provided to these businesses via the regulatory framework
- if interest rate hedging is not undertaken, it will adversely impact on the benchmark BBB+ credit rating and 60:40 gearing ratio.

8.8.6 Application of input cost escalators

The AER's detailed consideration and conclusions on the Qld DNSPs' input cost escalators, and the methodologies used to derive them, are set out at appendix H. This section addresses the specific application of those proposed cost escalators in the Qld

557 The AER assessed claims for interest rate hedging cost compensation as part of the Powerlink Transmission determination. Consistent with advice provided to the AER by NERA consulting, the AER did not provide such an allowance. AER, *Final decision – Powerlink transmission network revenue cap 2008–15*, 14 June 2007, pp. 95–105; and AER, *Final decision, WACC parameters*, May 2009, p. 168.

DNSPs' opex modelling to establish if their impact has been incorporated in to the forecasts appropriately.

Energex

Regulatory proposal

Energex engaged KPMG to develop escalation rates for the cost of labour, materials and contractors.[558] KPMG recommended annual escalation rates for nominal labour, materials and contractor costs over the next regulatory period, based on a combination of three statistical techniques and anecdotal evidence.[559] These escalation rates were applied in a similar manner across Energex's opex and capex forecasts where relevant. Energex's proposed real cost escalators, as applied to its opex forecasts, are set out in table 8.17.

Table 8.17: Energex real cost escalators applied to forecast opex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	1.53	2.05	0.00	0.00	0.00	0.00	0.00
Contractors	2.03	3.05	3.05	3.05	3.05	3.05	3.05
Labour	2.03	3.05	3.05	3.05	3.05	3.05	3.05

Source: Energex, Response to AER request, AER.EGX.26, 5 October 2009.

Based on Energex's modelling, the application of these escalators adds around $126 million to the total forecast opex for the next regulatory control period. Energex has not applied real cost escalation to its proposed debt and equity raising costs. The impact of Energex's proposed real cost escalators on its forecast opex is illustrated in table 8.18.

[558] Energex, *Regulatory proposal*, July 2009, p. 176.

[559] Energex, *Regulatory proposal*, July 2009, appendix 12.6, KPMG, Final report on escalation rates for labour, materials and contractors, p. 1.

Table 8.18: Impact of Energex's real cost escalators on forecast opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base opex ($m, 2007–08)	297.9	298.6	303.3	308.8	300.9	1509.5
Inflation adjustment to real $2009–10	14.8	14.9	15.1	15.4	15.0	75.2
Plus real cost escalation adjustment	14.6	19.6	25.1	30.7	36.3	126.3
Total controllable opex with real cost escalators	327.3	333.0	343.5	354.8	352.2	1710.9
Plus debt raising costs	7.2	8.0	9.0	9.9	10.7	44.8
Plus equity raising costs	20.6	19.8	18.8	15.7	12.6	87.4
Total opex as proposed	355.1	360.9	371.3	380.4	375.5	1843.1

Source: Energex, email response, issue number AER.EGX.22. 5 October 2009
Note: Totals may not add due to rounding.
Total controllable opex with real cost escalators includes self insurance.
However, self insurance is considered an uncontrollable cost.

Consultant review

As part of its review, PB was required to ensure that forecast changes in input costs have been appropriately reflected in the cost escalation calculations performed by Energex in forecasting opex. PB was provided with a model built by Energex to demonstrate the application of escalators within its cost estimating systems to the relevant expenditure type.[560] PB reviewed Energex's escalator model and found that:[561]

- the cost escalators are applied to the correct expenditure type categories and therefore the cost escalators are inherently weighted correctly according to the value of each expenditure type
- the expenditures at the asset category level sum to amounts that equal the total proposed expenditure.

Based on these findings, PB concluded that it was satisfied with the treatment of escalators within the Energex model and confident that the model represents the impact of escalation within Energex's enterprise systems.[562]

AER considerations

Modelling application

The AER notes that, because the application of escalators within Energex's enterprise systems could not be directly verified, PB's review was limited to an assessment of

[560] PB, *Report – Energex*, October 2009, p. 11.
[561] PB, *Report – Energex*, October 2009, p. 11.
[562] PB, *Report – Energex*, October 2009, p. 11.

the escalator model provided by Energex. The AER notes that this model demonstrates cost escalation from 2009–10 to 2014–15.[563]

The AER has considered PB's review of the cost escalator model and is satisfied with PB's findings in relation to Energex's escalation of costs from 2009–10 to 2014–15.

Energex indicated that while all of its expenditure estimates had been costed in 2008–09 dollars, its base year for calculating capex costs was 2007–08.[564]

However, as with the model provided to PB, Energex only provided cost escalators for 2009–10 to 2014–15.[565] Energex has since confirmed that its forecasts were based on 2007–08 costs which were escalated by the cost escalators presented in table 8.18.[566] The AER's considerations and conclusions on this issue are set out at appendix H.

Labour and contractors

The AER's detailed consideration and conclusions on Energex's input cost escalators, and the methodologies underpinning those escalators, are set out at appendix H to this draft decision. In summary, the AER does not consider Energex's proposed labour and contractor escalation rates are reasonable.

Regarding the application of the labour and contractor escalators in the expenditure modelling, the AER notes that they are applied generically to all internal and contract labour components of Energex's forecast opex and capex programs. The AER does not consider this is likely to result in forecasts which reflect the efficient costs incurred by a prudent operator in the circumstances of Energex as it does not differentiate between specialist and general labour resource requirements. The AER considers a weighted average escalation rate should be applied to Energex's contract and internal labour resources, based on the relative contribution of specialist and general labour resources to the forecast expenditure programs. The AER's detailed considerations on this issue are set out in appendix H.

Materials escalators

Consistent with its approach to escalating capex materials, Energex has applied no real escalation rate to general materials costs in preparing its opex forecasts for the next regulatory control period. The AER's detailed considerations on Energex's materials escalation are set out at appendix H of this draft decision. In summary, the AER does not accept Energex's proposed materials escalators.

While the AER considers that escalation of materials costs incurred in the course of opex activities may be acceptable in some cases, it does not consider that Energex has adequately demonstrated its assumed materials escalator, or the methodology underpinning it, reasonably reflect the nature of materials costs incurred during opex activities.

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563 Energex, email response, PB.EGX.MW.37, capex model, 11 August 2009, confidential.

564 Energex, *Regulatory proposal*, July 2009, RIN supporting documentation, RSD 2.3.10(1), Expenditure escalation processes, p. 3.

565 Energex, *Regulatory proposal*, July 2009, RIN supporting documentation, RSD 2.3.10(1), Expenditure escalation processes, table 1, p. 3.

566 Energex, email response, AER.EGX.26, received 5 October 2009, confidential.

Energex's proposed materials escalator is weighted toward growth in base commodities such as copper, aluminium, iron ore and zinc. The AER also notes that these inputs have been equally weighted, rather than weighted according to Energex's actual costs.[567]

As discussed in appendix H, the AER has not accepted Energex's materials cost escalator, and has developed substitute escalators for this draft decision. The AER's materials escalator has been estimated with reference to input cost weightings data reported by other Australian DNSPs relating to their forecast capex programs. The AER acknowledges that these weightings may not necessarily reflect the typical contribution of materials to opex activities.

Therefore, while the AER considers it appropriate to apply its materials escalator to Energex's forecast capex program, it is unclear that it reasonably reflects the mix of materials consumed in typical opex activities, and therefore may not represent a reasonable estimate of forecast movements in opex materials costs.

In the absence of an appropriately weighted escalator that reflects the materials reasonably expected to be consumed in Energex's opex activities, the AER has adopted Energex's proposed materials escalation rate of zero per cent real, for 2010–11 to 2014–15, and also considers this rate appropriate to apply in 2008–09 and 2009–10, in this case.

The AER requested Energex to model the impacts of the AER's decisions in relation to cost escalation. Energex advised that the adjustment to forecast opex is $140 million.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other supporting information, the AER is not satisfied that Energex's cost escalation reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed opex by $140 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for opex to comply with the NER. In coming to this view the AER has had regard to the opex factors. The AER's conclusion on Energex's forecast opex escalators is set out in table 8.19.

Table 8.19 AER conclusion on Energex's real cost escalators for opex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Contractors	0.77	1.38	0.14	0.58	1.17	1.54	1.53
Internal labour	–0.03	2.51	0.69	0.57	1.20	1.56	1.53

Source: AER analysis

[567] KPMG, response to AER information request on KPMG cost escalation reports, September 2009, p. 24.

The impact of the application of the AER's input cost escalators is illustrated in table 8.20.

Table 8.20: Impact of the application of AER input cost escalators on Energex's opex forecasts ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex controllable opex	324.5	330.0	340.4	351.6	349.2	1695.7
AER proposed controllable opex (excluding AER's revised cost escalator s)	320.0	327.2	337.7	349.0	346.6	1680.5
Impact of AER revised input cost escalators, as modelled by Energex	–16.4	–23.5	–29.0	–33.6	–37.9	–140.4
AER controllable opex	303.6	303.7	308.7	315.4	308.7	1540.1

Ergon Energy

Regulatory proposal

Ergon Energy engaged SKM to assist in developing cost escalation factors for materials, contractors, labour and other cost inputs to apply in developing its opex forecasts for the years 2008–09 to 2014–15.[568] The methods used by SKM to calculate the escalation rates for Ergon Energy's key input cost factors are discussed in more detail in appendix H. Ergon Energy's proposed input cost escalators for opex are illustrated in table 8.21.

Table 8.21: Ergon Energy nominal cost escalation factors for opex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	1.036	0.949	1.051	1.037	1.041	1.036	1.032
Contractors	1.051	1.051	1.044	1.045	1.045	1.045	1.045
Labour	1.051	1.051	1.044	1.045	1.045	1.045	1.045
Other	1.027	1.029	1.028	1.028	1.028	1.028	1.028

Source: Ergon Energy, *Regulatory proposal*, July 2009, p.336.

Ergon Energy advised that the four opex cost escalators were applied in the same manner across Ergon Energy's entire opex program.[569] SKM reviewed the application

568 Ergon Energy, *Regulatory proposal*, July 2009, pp. 335–336.
569 Ergon Energy, *Regulatory proposal*, July 2009, pp. 339–340.

of its cost escalators by Ergon Energy in its internal models and concluded that Ergon Energy applied the escalators in the manner SKM intended.[570]

Based on Ergon Energy's modelling, the application of these escalators adds around $186 million to the total forecast opex for the next regulatory control period. The impact of Ergon Energy's proposed real cost escalators on its forecast opex is illustrated in table 8.22

Table 8.22 Impact of real cost escalation on Ergon Energy's opex forecasts ($million)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base opex ($2007–08)	330.5	334.8	332.4	327.7	312.3	1637.7
Inflation adjustment to $2009–10	15.0	15.2	15.1	14.9	14.2	74.5
Escalation adjustment	24.5	31.5	38.0	44.1	48.2	186.3
Total opex ($2009–10)	370.1	381.5	385.5	386.7	374.7	1898.5

Source: Ergon Energy, email response to AER.ERG.14, 23 September 2009
Note: Totals may not add due to rounding

Materials

In addition to real cost escalators for capex components discussed in appendix H, Ergon Energy engaged SKM to develop a specific weighted average escalator to apply to the materials components of its forecast opex.[571] This escalator relates to the costs of items consumed in undertaking routine repairs and maintenance and includes meters, poles, conductors and connectors, underground cables and joints, and lines and fuses.[572]

Labour and contractors

Ergon Energy's forecast labour cost escalators were based on Ergon Energy's Union Collective Agreement 2008 and reflect a 4.5 per cent annual wage increase, plus an additional EDSD Review technical or professional allowance increment that is payable to Ergon Energy staff. Ergon Energy advised that payment of these allowances will cease in 2010–11.

Ergon Energy escalated its contract labour at the same rate as its EGW labour.[573] Ergon Energy advised that all contractor rates have been escalated by an increment based on its Union Collective Agreement 2008, which specifies a requirement that contractor staff rates are indexed to Ergon Energy's staff rates.[574]

570 Ergon Energy, *Regulatory proposal*, July 2009, p. 339.
571 Ergon Energy, *Regulatory proposal*, July 2009, attachment AR509, SKM, Indicative opex materials escalators.
572 Ergon Energy, *Regulatory proposal*, July 2009, p. 337.
573 Ergon Energy, request for information (Q.AER.ERG.08.3), 2 September 2009.
574 Ergon Energy, *Regulatory proposal*, July 2009, p. 336.

Other direct inputs

Ergon Energy assumed that the costs of all other direct inputs incurred in opex activities would increase, in real terms, in line with previous years' budget escalations.[575]

Consultant review

In assessing the application of Ergon Energy's opex escalators PB considered:[576]

- the combination of the process that Ergon Energy undertook to arrive at its forecast splits of opex into each of the escalation categories, which is informed by the annual business as usual budgeting process, and
- the stable outputs over the outlook period.

To form a view on the appropriateness of the methodology also considered the audit processes and results of a third-party audit conducted by PwC for Ergon Energy in order to provide validation of the methodology employed.[577]

From its review, PB concluded that the methodology and application of the escalators through the various opex model spreadsheets (as independently reviewed by PwC) is reasonable and correct.[578]

AER considerations

The AER notes PB's advice that Ergon Energy's application of escalators in its modelling spreadsheets appears reasonable and correct.

The AER also considers that the SKM's modelling approach underpinning Ergon Energy's opex modelling appears to be detailed and is likely to accurately reflect real cost changes over the next regulatory control period. This is supported by PB's conclusion that SKM's approach is a detailed approach that is suitable for application to Ergon Energy's forecast opex.

The AER notes PB findings in relation to the application of capex cost escalators by Ergon Energy in its capex modelling. The AER has reviewed Ergon Energy's opex model and confirmed that the errors found by PB do not appear to affect the forecast opex modelling.

Labour and contractors

The AER's detailed consideration and conclusions on Ergon Energy's input cost escalators, and the methodologies underpinning those escalators, are set out at appendix H to this draft decision. In summary, the AER does not consider Ergon Energy's proposed labour and contractor escalation rates are reasonable.

Regarding the application of this labour escalator in the expenditure modelling, the AER notes that the escalator is applied equally to all internal and contract labour

575 Ergon Energy, *Regulatory proposal*, July 2009, p. 336.
576 PB, *Report–Ergon Energy*, October 2009, p.16.
577 PB, *Report–Ergon Energy*, October 2009, p.14.
578 PB, *Report–Ergon Energy*, October 2009, p.17.

components of Ergon Energy's forecast opex and capex programs. The AER does not consider this is likely to result in forecasts which reflect the efficient costs incurred by a prudent operator in the circumstances of Ergon Energy as it does not differentiate between specialist and general labour resources. The AER considers specific weighted average escalation rates should be applied to Ergon Energy's internal labour resources, based on the relative contribution of specialist and general labour resources to the expenditure program. The AER also considers that its Queensland EGW growth rates should be applied to Ergon Energy's contractor costs.

Opex materials escalators

SKM developed Ergon Energy's opex materials escalator by using the relative proportions of relevant materials consumed in network maintenance activities. These proportions were then used to weight the contribution of the underlying input cost factors to the opex program, resulting in a weighted average escalation rate for these materials.

To establish the weighted average escalator, SKM relied on analysis provided by Ergon Energy which identified the breakdown of actual materials costs incurred in its operating and maintenance activities during 2006–07.[579] Ergon Energy's weighted average opex materials escalator has been based on the breakdown representative of the materials typically used in opex activities, as shown in table 8.23.[580]

Table 8.23 Ergon Energy component weightings for opex materials escalation (per cent)

Opex material cost component	Contribution to total opex materials costs
Overhead cables	9
Underground cables	12
Steelwork and fittings	1
Transformers	26
Other materials	52
Total	100

Source: Ergon Energy, *Regulatory proposal*, July 2009, attachment AR509, p.3 and; Ergon Energy, *Regulatory proposal*, July 2009, attachment PL848c.

The AER examined the methodology used by SKM in developing the materials escalator for Ergon Energy's opex forecasts, and has considered the materials component weightings used in its derivation.[581]

The use of a single reference year (in this case 2006–07) to derive a weighted materials escalator, assumes that the mix of materials used in opex activities during the next regulatory control period is consistent with the reference year observations.

[579] Ergon Energy, email response, Q.AER.ERG.15.02, 18 September 2009, confidential.
[580] Ergon Energy, *Regulatory proposal*, July 2009, attachment AR509, p.3.
[581] Ergon Energy, *Regulatory proposal*, July 2009, attachment PL848c.

To assess the reasonableness of this assumption, the AER reviewed Ergon Energy's forecast opex modelling to establish if the reference year reflects its expenditure profile for the next regulatory control period.

From this review, the AER is satisfied that the mix of materials used to derive the opex materials escalator represents a reasonable expectation of materials consumed in the course of normal opex activities. The escalator does not appear to unreasonably apply weight to materials/components that are unusual to opex activities, or would be considered unique to capital works, such as land and buildings. After considering Ergon Energy's forecast operating expenditure profile, The AER considers that the use of uniform weightings for each year of the next regulatory control period is unlikely to be material. The AER considers the materials reflected in Ergon Energy's weighted average escalator are typical of those consumed during opex activities, and would unlikely warrant capitalisation under existing accounting policies or prudent asset management strategies.

While the AER has previously considered that opex materials costs should generally be escalated by CPI only, the methodology and assumptions underpinning SKM's weighted opex materials escalator appear sound, and consistent with those applied in developing its capex materials escalators. On this basis, the AER considers it reasonable that the costs of similar materials be escalated consistently, regardless of whether the costs of those materials are capitalised or expensed.

However, while it accepts the derivation of the weighted opex materials escalator as reasonable, the AER does not accept the underlying input cost factor forecasts used by SKM to derive the asset class escalators weighted within Ergon Energy's opex materials escalator. The AER's conclusions on input cost factors forecasts are discussed in appendix H.

The AER requested Ergon Energy to model the impacts of the AER's decisions in relation to cost escalation.[582] Ergon Energy advised that the adjustment to forecast opex is $264 million.[583]

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's application of real cost escalators reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed opex by $264 million results in expenditures that reasonably reflect the opex criteria, including the opex objectives, and is the minimum adjustment necessary for the escalation amount to comply with the NER. In coming to this view the AER has had regard to the opex factors. The AER's conclusion on Ergon Energy's forecast opex escalators is set out in table 8.24

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582 AER, modelling request, 6 November 2009.
583 Ergon Energy, modelling response PL869c, 13 November 2009, confidential.

Table 8.24: AER conclusion on Ergon Energy's real cost escalators for opex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	0.99	0.99	1.07	1.07	1.04	1.03	1.02
Contractors	0.90	1.50	0.10	0.60	1.20	1.60	1.50
Internal labour	0.07	2.13	0.58	0.58	1.16	1.54	1.53
Other	0.93	0.15	0.59	0.29	0.29	0.29	0.29

The impact of the application of the AER's input cost escalators is illustrated in table 8.25.

Table 8.25: Impact of the application of AER input cost escalators on Ergon Energy's opex forecasts ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy's controllable opex	365.9	377.3	381.2	3823	370.2	1876.9
AER proposed controllable opex (excluding AER's revised escalators.)	333.2	341.1	340.9	338.8	326.3	1680.3
Impact of AER's revised escalators, modelled by Ergon Energy	–34.8	–46.3	–54.7	–61.7	–66.4	–263.9
Adjustment to reinstate overheads removed in adjustments	18.2	20.3	14.1	11.7	11.1	75.4
AER controllable opex	316.6	315.1	300.3	288.8	271.0	1492.1

Note: Totals may not add due to rounding.

8.9 AER conclusion

8.9.1 Energex total opex

The AER has considered Energex's proposed forecast opex allowance of $1843 million and, for the reasons outlined in this draft decision, is not satisfied that the total opex forecast by Energex reasonably reflects the opex criteria under clause 6.5.6(c) of the NER. In drawing this conclusion, the AER has had regard to the opex factors set out in clause 6.5.6(e) of the NER.

As the AER is not satisfied that Energex's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in Energex's regulatory proposal. Therefore, the AER is required under clause

6.12.1(4)(ii) to provide an estimate of the total opex that Energex will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

On the basis of its analysis of Energex's proposed opex forecast and the advice of PB, the AER has applied a reduction of $256 million to Energex's proposed opex. This represents a reduction of around 14 per cent of Energex's proposed opex of $1843 million and results in a revised forecast total opex allowance of $1586 million. Table 8.26 shows a comparison of Energex's proposed total opex and the AER's draft decision on Energex's total opex.

This revised estimate represents the AER's estimate of the efficient total opex costs that a prudent operator in the circumstances of Energex would require to achieve the opex objectives. The AER considers this reduction is the minimum adjustment necessary to ensure Energex's proposed opex forecast meets the opex criteria. The AER is satisfied that the revised total forecast opex of $1586 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors.

Table 8.26: AER conclusion on Energex's total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex's controllable opex	324.5	360.8	340.4	351.6	349.2	1695.7
Self insurance costs	2.8	2.9	3.1	3.2	3.0	15.1
Debt raising costs	7.2	8.1	9.0	9.9	10.7	44.8
Equity raising costs	20.6	19.8	18.8	15.7	12.6	87.4
Energex's total opex	355.1	360.9	371.3	380.4	375.5	1843.1
AER's controllable opex (including input cost escalators)	303.6	303.7	308.7	315.4	308.7	1540.1
Self insurance costs	0.0	0.0	0.0	0.0	0.0	0.04
Debt raising costs	4.2	4.6	5.1	5.5	6.0	25.3
Equity raising costs[a]	–	–	–	–	–	–
Adjustment to reinstated indirect costs removed in adjustments[b]	5.4	3.8	4.2	3.5	4.0	20.9
AER total opex	313.2	312.2	318.0	324.4	318.7	1586.3

Note: Totals may not add due to rounding.

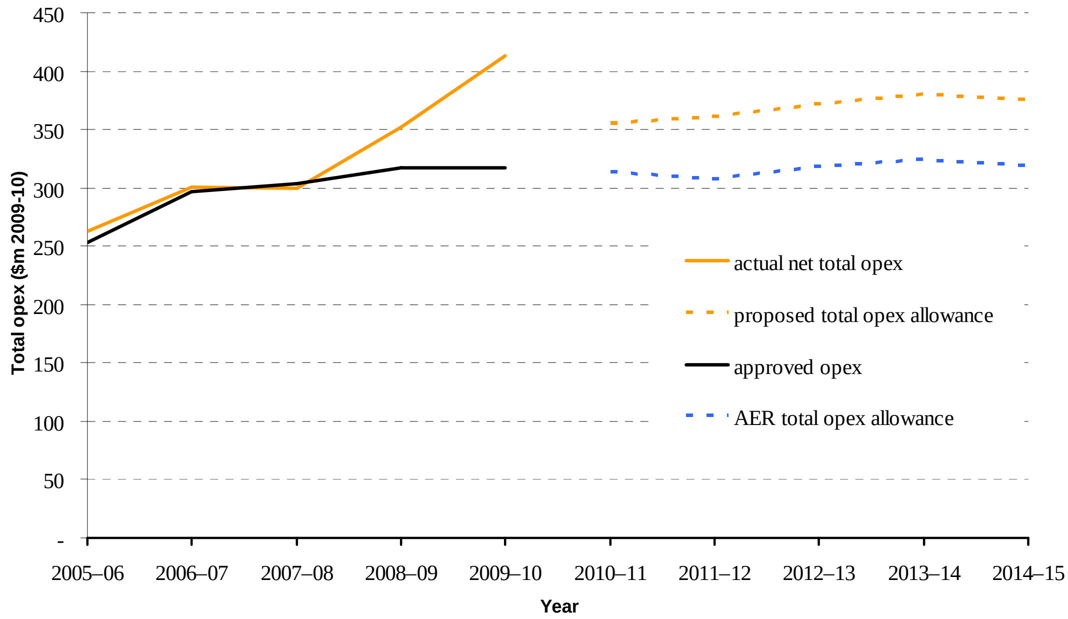
(a) The AER will allow Energex to amortise a total of $36.8 million ($2009–10) for benchmark equity raising costs for the next regulatory control period.

(b) The indirect costs included in the AER's adjustments to opex are not to be removed from Energex's capex allowance. This is because, with the exception of an adjustment for ICT services and sponsorship costs, the AER has not proposed any adjustments to Energex's indirect costs, as discussed in section 7.8.4 of the capex chapter.

As discussed in section 8.8.5.3 the AER will allow Energex to amortise a total of $36.8 million in benchmark equity raising costs in the next regulatory control period.

Figure 8.5 illustrates the AER's draft decision on Energex's forecast opex compared to its proposed allowance, and current period opex outcomes.

Figure 8.5: Energex proposed/actual opex and regulated allowances 2005–2015 ($m, 2009–10)



Source: AER analysis

8.9.2 Ergon Energy total opex

The AER has considered Ergon Energy's forecast total opex of $1993 million, and for the reasons outlined in this draft decision is not satisfied that this total opex forecast proposed by Ergon Energy reasonably reflects the opex criteria under clause 6.5.6(c) of the NER. In drawing this conclusion the AER has had regard to the opex factors set out in clause 6.5.6(e) of the NER.

As the AER is not satisfied that Ergon Energy's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in Ergon Energy's regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) to provide an estimate of the total opex that Ergon Energy will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

On the basis of its analysis of Ergon Energy's proposed opex forecast and the advice of PB, the AER has applied a reduction of $479 million to Ergon Energy's proposed opex. This represents a reduction of around 24 per cent of Ergon Energy's proposed opex of $1993 million and results in a revised forecast total opex allowance of $1514 million. Table 8.27 shows a comparison of Ergon Energy's proposed total opex and the AER's draft decision on Ergon Energy's total opex.

This revised estimate represents the AER's estimate of the efficient total opex costs that a prudent operator in the circumstances of Ergon Energy would require to achieve the opex objectives. The AER considers this reduction is the minimum adjustment necessary to ensure Ergon Energy's proposed opex forecast meets the opex criteria. The AER is satisfied that the revised total forecast opex of $1514 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors.

Table 8.27: AER conclusion on Ergon Energy's total opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy controllable opex forecast	365.9	377.3	381.2	382.3	370.2	1876.9
Self insurance costs	4.2	4.2	4.3	4.4	4.5	21.5
Debt and equity raising costs	11.9	16.3	22.0	22.8	21.2	94.1
Ergon Energy total opex	382.0	397.8	407.5	409.5	395.9	1992.6
AER controllable opex (including input cost escalation and reinstated shared costs)[a]	316.7	315.2	300.4	288.9	271.0	1492.1
Self insurance costs	0.0	0.0	0.0	0.0	0.0	0.016
Equity raising costs[b]	–	–	–	–	–	–
Debt raising costs	3.8	4.0	4.4	4.7	5.1	22.0
AER total opex	320.5	319.2	304.8	293.6	276.1	1514.2

Note: Totals may not add due to rounding.

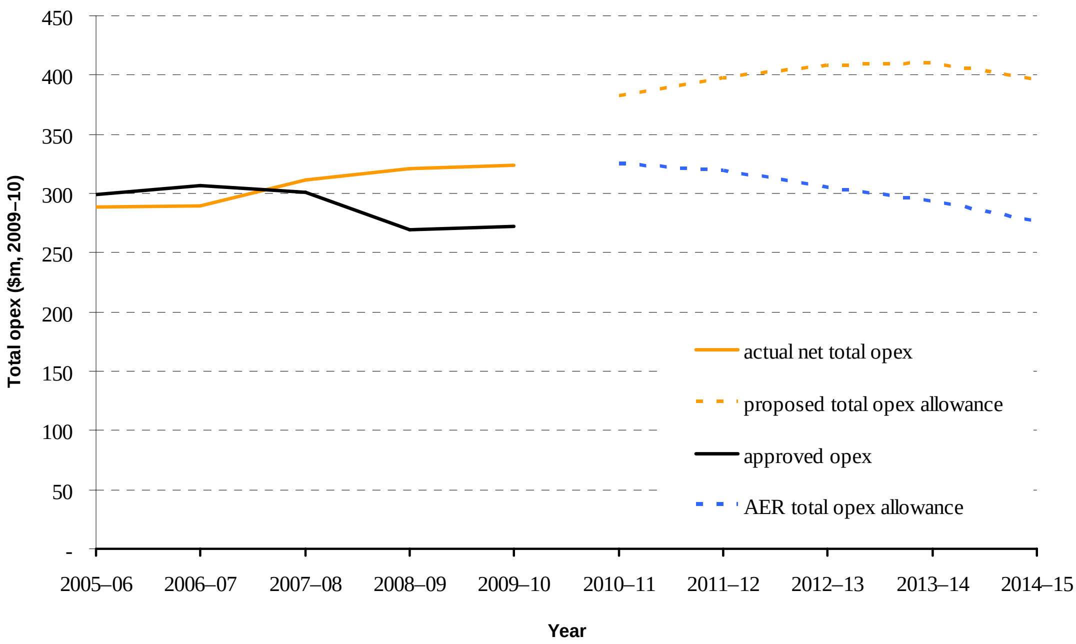
(a) The shared costs included in the AER's deductions to opex are not to be removed from Ergon Energy's opex allowance. This is because, with the exception of an adjustment for ICT services and sponsorship costs, the AER has not proposed any adjustments to Ergon Energy's shared costs, as discussed in section 7.8.4 of the capex chapter.

(b) The AER will allow Ergon Energy to amortise a total of 11.9 million ($2009–10) for benchmark equity raising costs for the next regulatory control period.

As discussed in section 8.8.5.3 the AER will allow Ergon Energy to amortise a total of $11.9 million in benchmark equity raising costs for the next regulatory control period.

Figure 8.6 illustrates the AER's draft decision on Ergon Energy's forecast opex compared to its proposed allowance, and current period opex.

Figure 8.6: Ergon Energy's proposed/actual opex and regulated allowances 2005–2015 ($m, 2009–10)



Source: AER analysis.

8.10 AER draft decision

In accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept Energex's proposed forecast opex for the next regulatory control period. The AER is not satisfied that Energex's forecast opex, taking into account the opex factors, reasonably reflects the opex criteria in clause 6.5.6 of the NER.

The AER's reasons are set out in section 8.8 of this draft decision.

The AER's estimate of Energex's required opex for the next regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out at table 8.26 of this draft decision.

In accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept Ergon Energy's proposed forecast opex for the next regulatory control period. The AER is not satisfied that Ergon Energy's forecast opex, taking into account the opex factors, reasonably reflects the opex criteria in clause 6.5.6 of the NER.

The AER's reasons are set out in section 8.8 of this draft decision.

The AER's estimate of Ergon Energy's required opex for the next regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out at table 8.27 of this draft decision.

9 Estimated corporate income tax

9.1 Introduction

This chapter sets out the AER's assessment of the estimated corporate income tax liabilities proposed by the Qld DNSPs during the next regulatory control period. Two key issues discussed in this chapter are the value of the assumed utilisation of imputation credits (gamma) and determination of the tax asset bases for the Qld DNSPs.

9.2 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 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:
>
> ETI_t 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;
>
> r_t 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.

9.2.1 Assumed utilisation of imputation credits (gamma)

The formula outlined in clause 6.5.3 of the NER 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')[584] that offsets part or all of their personal income tax liabilities. For eligible shareholders, imputation credits represent

[584] In this chapter the terms imputation credit and franking credit are used interchangeably.

a benefit from the investment in addition to any cash dividend or capital gains received.[585]

The generally accepted regulatory approach to date in Australia has been to define the value of imputation credits in accordance with the Monkhouse definition.[586] Under this approach, gamma is defined as a product of the 'imputation credit payout ratio' (F) and the 'utilisation rate' (θ or 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).[587]

9.2.1.1 Statement of regulatory intent

Under clause 6.5.4(a) of the NER, the AER conducted a review (the WACC review)[588] of the following matters referred to in clauses 6.5.2 and 6.5.3 of the NER:[589]

- the nominal risk–free rate
- the equity beta
- 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
- the credit rating levels
- the assumed utilisation of imputation credits (gamma).

On completion of the WACC review the AER issued the SORI regarding these values, methods and credit rating levels.[590] 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 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:

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585 Although foreign investors do not pay Australian personal income taxes, they may receive a credit for company tax paid from their home country government, depending on the inter-country tax arrangements.

586 P. Monkhouse, *Adapting 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.

587 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009, p. 7.

588 AER, *Final decision, Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, May 2009.

589 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.

590 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009.

(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 underlying criteria used by the AER in the SORI in relation to gamma are:[591]

- 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
- 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
- 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
  - having regard to the economic costs and risks of the potential for under and over investment.

9.2.2 Determining the tax asset base

As part of its 2005 Determination, the QCA applied a post–tax cost of capital for the Qld DNSPs.[592] Under this approach, an allowance for tax was included in the annual expenditure cash flows for the Qld DNSPs. Where differences arose between the forecast tax allowance and the actual tax paid by a business, the difference was carried forward into subsequent years with an adjustment made to future allowed revenue recovery. In other words, an unders and overs account for tax was maintained.

Unlike the QCA approach, under clause 6.5.3 of the NER the AER must estimate the taxable income that would be earned by a benchmark efficient entity. This estimate is to be calculated using the post–tax revenue model (PTRM).

In estimating the taxable income of a business, the AER must also take into account estimated depreciation for tax purposes. To determine the depreciation for tax purposes, it is necessary to calculate the tax asset values and the depreciation that

591 NER, clause 6.5.4(e); and NEL, section 7A.
592 QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 124.

results from those tax asset values. This depreciation is then offset against the DNSPs forecast income to arrive at a forecast level of taxable income.

As historical tax depreciation may differ from regulatory depreciation, the tax asset values may differ from the regulatory asset values used in the PTRM. Further explanation of these issues can be found in the AER's issues paper on transitioning businesses from pre–tax to post–tax regulation.[593]

9.3 Queensland DNSP regulatory proposals

9.3.1 Assumed utilisation of imputation credits (gamma)

Energex and Ergon Energy proposed a gamma of 0.2 on the basis of the Joint Industry Associations' submission to the AER during the WACC review and new work conducted by Synergies.[594]

9.3.1.1 Energex

Energex did not accept the gamma of 0.65 from the WACC review as it did not consider it to be reasonable based on current market evidence. Energex argued that if the AER's assessment framework is applied, it would propose:[595]

- a lower bound of 0 based upon the Joint Industry Associations' submission to the WACC review
- an upper bound of 0.35 based upon tax statistics and a payout ratio of 100 per cent.

Energex proposed a gamma of 0.2 as more appropriate and used this value in its regulatory proposal.[596]

9.3.1.2 Ergon Energy

Ergon Energy argued that the AER, in determining a value of 0.65 in the SORI, did not give sufficient weight to the evidence before it.[597]

In referring to the findings of the Synergies report submitted with its regulatory proposal, Ergon Energy noted:[598]

- not all imputation credits created are distributed and of those distributed, not all are claimed by individual shareholders

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[593] AER, *Preliminary positions, matters relevant to distribution determinations for Act and NSW DNSPs for 2009–2014*, November 2007, appendix A: AER, Issues paper, Electricity Distribution Network Service Providers: Transition of energy businesses from pre–tax to post–tax regulation, June 2007.
[594] Energex, *Regulatory proposal*, July 2009, pp. 242–243; Ergon, *Regulatory proposal*, July 2009, p. 389; and Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009.
[595] Energex, *Regulatory proposal*, July 2009, p. 243.
[596] Energex, *Regulatory proposal*, July 2009, p. 243.
[597] Ergon Energy, *Regulatory proposal*, July 2009, p. 389.
[598] Ergon Energy, *Regulatory proposal*, July 2009, p. 389.

- based on actual observed payout ratios from tax statistics, the maximum possible amount of credits claimed is 23 per cent

- if this is adjusted to the AER's assumed payout ratio, the maximum possible amount of credits claimed is 35 per cent.

On the basis of advice from Synergies, Ergon Energy proposed an estimate of 0.2 for gamma.[599]

9.3.2 Estimated cost of corporate income tax

The Qld DNSPs proposed an approach to determining their tax liability based on forecast revenues over the next regulatory control period where they applied the PTRM, which calculates a tax allowance in accordance with the methodology set out in clause 6.5.3 of the NER. It should be noted that the allowance for tax is an output of the PTRM rather than an input to be specified or proposed by the regulated business.

The relevant inputs to the PTRM calculation of an allowance for tax include the:

- tax remaining life for each asset class

- tax standard life for each asset class

- tax asset base or remaining tax asset value for each asset class.

9.3.2.1 Energex

Energex established a tax asset base as at 1 July 2010 to determine forecast tax depreciation.[600] Energex established its tax asset base by:

- adopting the tax asset base from the most recent National Tax Equivalents Regime (NTER) tax return to the Australian Tax Office (ATO) being financial year ended 30 June 2008

- separating the tax value of assets as at 30 June 2008 into RAB and non-RAB components

- rolling forward the resultant tax RAB to 1 July 2010 using the AER's roll forward model (RFM), applying tax depreciation and actual capex and disposals.

Applying this method, Energex proposed a tax asset base as at 1 July 2010 of $3759 million.

To determine the annual tax payable, Energex applied a tax rate of 30 per cent to the annual revenue net of tax depreciation generated from the PTRM. The resultant annual forecast tax liability proposed by Energex is set out in table 9.1.[601]

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599 Ergon Energy, *Regulatory proposal*, July 2009, p. 38.
600 Energex, *Regulatory proposal*, July 2009, p. 247.

Table 9.1: Energex proposed annual forecast tax liability ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Forecast tax depreciation	146.7	176.9	209.2	241.8	270.9
Tax payable	103.4	114.6	126.9	139.9	150.4
Less value of imputation credits	20.7	22.9	25.4	28.0	30.1
Net tax allowance	82.7	91.7	101.5	111.9	120.3

Source: Energex, email to the AER, Issue no: AER.EGX.24, 1 October 2009, confidential.

9.3.2.2 Ergon Energy

Ergon Energy applied a similar methodology to that of Energex to determine forecast tax depreciation. Whereas Energex applied its NTER tax asset base as at 30 June 2008 as the start date, Ergon Energy applied a date of 1 July 2005. Applying the same method, Ergon Energy proposed a tax asset base as at 1 July 2010 of $4000 million.[602]

To determine the annual tax payable, Ergon Energy has applied a tax rate of 30 per cent to the annual revenue net of tax depreciation generated from the PTRM. The resultant annual forecast tax liability proposed by Ergon Energy is set out in table 9.2.

Ergon Energy forecast no tax liability for 2010–11 due to the carry forward of tax losses from previous years.

Table 9.2: Ergon Energy proposed annual forecast tax liability ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Forecast tax depreciation	0.0	263.7	297.3	319.0	359.7
Tax payable	0.0	21.7	77.2	94.6	100.5
Less value of imputation credits	0.0	4.3	15.4	18.9	20.1
Net tax allowance	0.0	17.3	61.8	75.6	80.4

Source: Ergon Energy, *Regulatory proposal*, July 2009, p. 371 and PTRM, worksheet 'Analysis'.

9.4 Submissions

Energy Users Association of Australia (EUAA) noted that the Qld DNSPs have both projected large increases in future tax liability compared to the current regulatory control period. It stated that these future tax liabilities would be payable to the Queensland Government and that electricity users in Queensland are being taxed via their electricity distribution charges. EUAA considered that such outcomes are

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601 Subsequent to its proposal, Energex advised that the table at p. 246 of its regulatory proposal contained errors. Corrected values were provided. Energex, email to AER, issue no: AER.EGX.24, 1 October 2009, confidential.

602 Ergon Energy, *Regulatory proposal*, July 2009, p. 371.

inconsistent with the objective of the NEM and expected the AER to take action to ensure that such outcomes are avoided.[603]

9.5 Issues and AER considerations

9.5.1 Assumed utilisation of imputation credits (gamma)

The SORI determined a value of gamma of 0.65. Under clause 6.5.2(g), the AER must determine whether there is persuasive evidence to justify a departure from this value. The following sections consider the Qld DNSPs' proposals and other material before the AER in terms of:

- the Qld DNSPs' general criticisms of the approach taken by the AER in the WACC review
- estimating the distribution of imputation credits (payout ratio)
- estimating theta empirically and the Synergies' tax statistics study
- selecting gamma from a reasonable range.

9.5.1.1 General criticisms of approach taken in the WACC review

The Qld DNSPs argued that the AER did not give sufficient weight to the arguments put forward by the Joint Industry Associations in the WACC review.[604] Energex argued, despite the AER's findings in the WACC review, that:[605]

- the value of gamma can only be derived from market data
- consideration of a range of recent reputable Australian studies suggests the value of gamma has fallen considerably and may indeed have no value.

Ergon Energy contended that by adopting a value of 0.65 during the WACC review, the AER gave insufficient weight to the volume of evidence provided in several reputable recent studies, namely the expert reports provided as part of the Joint Industry Associations' submission.[606]

AER's considerations

During the WACC review the AER considered and responded to the expert evidence and fundamental issues referred to by the Qld DNSPs with respect to 'non–market' measures. The AER's reason for placing an equal amount of weight on both non-market and market based estimates was:[607]

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603 EUAA, *Submission to the AER*, August 2009, p. 6.
604 Energex, *Regulatory proposal*, July 2009, p. 242; and Ergon Energy, *Regulatory proposal*, July 2009, p. 389.
605 Energex, *Regulatory proposal*, July 2009, p. 242.
606 Ergon Energy, *Regulatory proposal*, July 2009, p. 389.
607 AER, *Final decision, WACC parameters,* May 2009, pp. 448, 456 and 467.

- the most reasonable and reliable studies available to the AER at the time of the WACC review were the Beggs and Skeels[608] dividend drop-off study, and the Handley and Maheswaran[609] tax statistics study

- the methodologies used in both studies were attempting to estimate the same value.

Therefore, the AER concluded that both estimates should be afforded the same weight.[610]

The Qld DNSPs have not identified specific areas of concern regarding the AER's approach to determining a gamma during the WACC review. Accordingly, the AER considers that in this regard, the Qld DNSPs have not demonstrated any material change in circumstances since the WACC review or any other relevant factor that, in light of the underlying criteria, would now make the gamma of 0.65 set in the SORI inappropriate. The AER considers that there is no persuasive evidence justifying a departure from the AER's approach to determining gamma during the WACC review.

9.5.1.2 Estimating the payout ratio

The generally accepted regulatory approach in Australia has been to define the value of gamma as a product of the imputation credit payout ratio and the utilisation rate (theta).

The AER notes that there appears to be broad agreement that determining the payout ratio requires consideration of two separate but inter-related matters:[611]

- the proportion of imputation credits generated each year that are distributed in that same year (the annual payout ratio)

- the value of imputation credits that are not immediately distributed, but rather retained within the firm for a period of time (the value of retained credits).

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.[612] 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 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.

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608 D. Beggs and C. L. Skeels, *Market arbitrage of cash dividends and franking credits*, The Economic Record, vol.82, no.258, September 2006.

609 J. C. Handley and K. Maheswaran, *A measure of the efficacy of the Australian imputation tax system*, The Economic Record, vol.84, no.264, March 2008.

610 AER, *Final decision, WACC parameters,* May 2009, p. 467.

611 AER, *Final decision, WACC parameters,* May 2009, p. 415.

612 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).

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 as follows:[613]

- 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 1994 Officer CAPM framework (the Officer framework)[614]

- in accordance with the framework proposed by the National Economic Research Associates (NERA), based on a reasonable set of assumptions[615] the AER considered that a reasonable estimate of the payout ratio using the analysis suggested by NERA is between 91 and 98 per cent.

On the basis of these considerations the AER concluded 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 Officer framework and the modelling assumptions in the AER's PTRM.

Qld DNSP regulatory proposals

The payout ratio is not discussed explicitly by the Qld DNSPs in their regulatory proposals. However, by proposing a gamma of 0.2, they are proposing a departure in the payout ratio from 100 per cent to 71 per cent.[616] This has been justified on the basis of Synergies' advice.[617]

Synergies' advice on payout ratios

Synergies had a number of fundamental concerns with Handley's advice on payout ratios, including issues of fact. For example, in relation to the assumption of a 100 per cent payout, Synergies noted that Handley (in his advice for the WACC review) assumed the:[618]

- Officer framework is based upon a perpetuity framework and hence the model assumes a 100 per cent payout ratio

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613 AER, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, Final decision, May 2009, pp. 419–420.

614 R. R. Officer, *The cost of capital under an imputation tax system*, Accounting and Finance, Vol.34, 1994.

615 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, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, Final decision, May 2009, pp. 418–419.

616 Energex, *Regulatory proposal*, July 2009, p. 245; and Ergon Energy, *Regulatory proposal*, July 2009, p. 389.

617 Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, pp. 3 and 8, confidential.

618 Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, p. 3, confidential.

- 100 per cent payout ratio is also consistent with the Miller and Modigliani framework.

Synergies contended:[619]

- it is true that the Officer framework is a perpetuity model however this does not imply a 100 per cent payout ratio – instead it implies a constant payout rate, which Synergies observed to be around 70 per cent

- while Miller and Modigliani allowed the payout ratio to vary to illustrate the irrelevance of dividends, this is not an explicit assumption of their model.

Synergies contended if the AER's methodology for estimating gamma (the payout ratio multiplied by theta) is properly interpreted and applied, the value for gamma must be somewhere between 0 and 0.23.[620] This is calculated by:

- accepting the Joint Industry Associations submissions with respect to gamma (value of zero)

- adopting the payout ratio derived from its approach (66 per cent) and a theta estimate from its tax statistics study of 0.35.

Consultant review

The AER sought the assistance of Associate Professor John Handley to assess issues raised by Synergies on behalf of the Qld DNSPs.

With respect to Synergies arguments on the payout ratio, Handley noted:[621]

> It is again repeated that the practice that firms usually do not distribute 100% of the free cash flow and imputation credits generated each period is not in dispute.
>
> What is in dispute, however, is the conclusion then drawn by Synergies and Professor Officer that this evidence supports the view that around 30% of credits are retained indefinitely and so have zero value. To assume that retained credits will never be paid out is an extreme assumption. Never is a very long time. In effect, the suggestion is that one should extrapolate a trend, based on only twenty years of observations, into the future for an indefinite period of time.
>
> The assumption that some proportion of credits generated each period are never paid out, requires the dual implicit assumption that some proportion of free cash flow generated each period are similarly never paid out. Whilst the value of retained credits is subject to time decay, the value of retained cash flow is not subject to time decay provided one makes the additional assumption that the retained free cash flow is reinvested at the firm's cost of

619 Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, p. 3, confidential.

620 Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, p. 8, confidential.

621 J. C. Handley, *RE: Advice on gamma in relation to the 2010-2015 QLD/SA electricity distribution determinations, Memorandum to the AER*, 20 October 2009, p. 10.

> capital. In my opinion, despite the criticism, an assumption of full distribution of credits each period is no more extreme than is assuming that retained cash can be reinvested at the cost of capital in perpetuity.

AER considerations

The AER notes the advice from Handley and considers assuming that undistributed imputation credits have zero value is unrealistic. While these retained credits are potentially subject to time value decay, the process of determining whether this actually occurs or whether the associated cash flows are reinvested by the business would require considerable detailed investigation.

The AER also notes that it is not uncommon to use simplifying assumptions with respect to materiality of the time value impacts. For example the PTRM makes assumptions about the timing of cash flows for the sake of simplicity. Therefore, consistent with its findings in the WACC review, the AER considers that the potential benefits from measuring an estimate of the decay in value of distributed imputation credits is outweighed by the complexity introduced by the extra parameters required in achieving this degree of modelling accuracy.

In the context of the payout ratio, the AER considers that DNSPs have not demonstrated any material change in circumstances since the WACC review or any other relevant factor that, in light of the underlying criteria, would now make the gamma of 0.65 specified in the SORI inappropriate. The AER considers that there is no persuasive evidence justifying a departure from the AER's position on the payout ratio of 100 per cent reached during the WACC review.

9.5.1.3 Estimating theta empirically

In the WACC review the AER relied upon two approaches to inform the reasonable range of empirical estimates of theta. These were dividend drop-off studies, and studies which examined tax statistics. The AER has received new information from the Qld DNSPs on values inferred from tax statistics.

The AER notes that the results generated by studies that attempt to infer theta from market prices should be treated with caution, given the inherent noise and anomalies in estimation. Notwithstanding these concerns, the AER considers that inferential studies (in particular dividend drop-off studies) can still provide useful information on the value of imputation credits in the Australian economy.

Statement of regulatory intent

During the WACC review the AER concluded that the methodology used in the Handley and Maheswaran 2008 study provided a relevant and reliable estimate of theta in the post July 2000 period. The AER concluded that a reasonable range of theta estimated from tax statistics is 0.67 to 0.81 for this period. Selecting the mid–point gave a point estimate for theta derived from tax statistics of 0.74.[622]

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[622] AER, *Final decision*, *WACC parameters,* May 2009, p. 455.

Qld DNSPs regulatory proposals

Energex criticised the tax statistics approach as it does not reflect the risks borne by shareholders in holding shares to derive imputation credits.[623] Based upon Synergies' advice, the Qld DNSPs contended the range of values for gamma inferred from tax statistics is 0.23 to 0.35.[624]

Synergies raised the following issues:[625]

- Handley and Maheswaran's 2008 study did not provide a value for gamma and will overstate the observed upper bound
- the tax statistics approach relied on by the AER did not take into consideration the risk that shareholders bear in earning the dividends and credits
- between 2003 and 2007, the payout ratio varied between 58 and 77 per cent with the average proportion distributed being 66 per cent—this is broadly consistent with the findings of Hathaway and Officer
- of the 66 per cent of imputation credits utilised, 35 per cent were claimed—with gamma ranging between 0.23 (as a proportion of total imputation credit created) to 0.35 depending on the payout ratio assumption.

Consultants review

As part of his advice to the AER on the Synergies tax statistics study, Handley found that Synergies' estimates of credit utilisation rates were not reliable, since:[626]

- Synergies' estimate is clearly implausibly low, particularly considering that imputation credits have been refundable to resident individuals, super funds and certain other entities since 1 July 2000 (reflecting changes to Australian tax laws)
- its approach is flawed in that it has failed to take into account the fact that the aggregate amount of franked dividends paid each year, as disclosed by the Australian Tax Office (ATO), includes an unknown amount of double counting which arises as dividends are paid along chains of interposed entities within the same corporate group structure
- the amount of franked dividends paid each year and the corresponding estimate of the amount of imputation credits distributed each year are therefore overstated by an unknown amount and accordingly, Synergies' estimate of the credit utilisation rate is understated by an unknown amount.

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623 Energex, *Regulatory proposal*, July 2009, p. 242.

624 Energex, *Regulatory proposal*, July 2009, p. 242; and Ergon Energy, *Regulatory proposal*, July 2009, p. 389.

625 Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, pp. 4–8, confidential.

626 J. C. Handley, *RE: Advice on gamma in relation to the 2010-2015 QLD/SA electricity distribution determinations, Memorandum to the AER,* 20 October 2009, pp. 7–8.

AER considerations

Overall, the AER considers that while Synergies has presented new information, it suffers from methodological flaws, as identified by Handley, and therefore does not constitute persuasive evidence under clause 6.5.4(g).

The AER's detailed considerations of the Qld DNSPs' proposals and Synergies' advice in particular are set out below according to the following issues:

- deficiencies in using tax statistics to inform theta estimates
- payout ratios inferred from tax statistics
- theta inferred from tax statistics
- gamma inferred from Synergies' advice.

Deficiencies in using tax statistics to inform theta estimates

The AER notes that Synergies raised concerns with several areas of the SORI, but claimed it did not pursue issues with respect to the payout ratio or other issues considered in the WACC review.[627] However, the AER also notes Synergies responded to comments made on the payout ratio, which contradicts its initial position. This included the concern that the theta implied from tax statistics is not a market-based approach.

Energex and Synergies raised concerns about theta estimates being inferred from tax statistics rather from a market-based estimate (for example dividend drop-off studies).[628] The AER acknowledges that tax statistics are based upon book values which may not reflect the market. That said, consistent with the AER's approach to gearing in the WACC review[629], the AER considers that book values can be used as a proxy for market values. However, the AER notes all methodologies used to inform the reasonable range of estimates have inherent strengths and weaknesses. For example, the reliability of estimates derived from dividend drop-off studies, are affected by noisy data and multi-collinearity.[630] That said, Energex and Synergies were silent on the fact that the payout ratio of 71 per cent for imputation credits has been derived from tax statistics rather than from a market-based estimate. The AER considers this inconsistency calls into question their concerns about non-market based estimates.

[627] Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, p. 2, confidential.

[628] Energex, *Regulatory proposal*, July 2009, p. 242; and Ergon Energy, *Regulatory proposal*, July 2009, p. 389.

[629] AER, *Final decision*, *WACC parameters,* May 2009, p. 120.

[630] The AER notes it recently identified a number of concerns in relation to the updated dividend drop-off study provided by ETSA Utilities. See AER, *Draft decision*, South Australia draft distribution determination, pp. 263–272.

Payout ratios inferred by tax statistics

Synergies found that between 2003 and 2007, the payout ratio varied between 58 and 77 per cent with the average proportion distributed being 66 per cent, and that this is broadly consistent with the findings of Hathaway and Officer.[631]

The AER notes that Synergies attempted to estimate a payout ratio consistent with Hathaway and Officer's 2004 study and has therefore used year on year rather than aggregate totals. Further, the AER (and Handley) have already acknowledged it is likely the actual annual payout ratio is less than 100 per cent. However, the AER considers that over time a business will distribute credits through a number of means (such as dividend re-investment plans) to release the value of credits to shareholders even if equity is retained.

The AER also notes that it may be inappropriate to compare dividend payout ratios derived from taxation statistics (and tax laws) to dividend payout ratios derived from annual reports (and company law). Tax laws consider that profits comprise all profits earned (including retained earnings) and dividends include not only paid out dividends and dividend re-investment schemes but also share buybacks (where the difference between the price paid and the market price is treated as a dividend). Company law treats profits as those earned during the financial year and dividends as those amounts paid out to shareholders.

The most critical issue with Synergies' tax study, as pointed out by Handley, is that that figures obtained using company tax statistics are subject to double counting due to complex corporate structures where dividends are paid through multiple entities which consequently exaggerates the number of imputation credits distributed.[632] Therefore, the AER considers that the payout ratios estimated by Synergies may be unreliable due to the presence of double counting. The AER notes that Synergies stated that the payout ratio estimated in its report is broadly consistent with Hathaway and Officer.[633] The AER considers in light of views of advice from Handley about double counting present in company taxation statistics, that the payout ratio of 71 per cent in Hathaway and Officer is likely to underestimate the payout ratio. The AER observes:

- the time decay analysis of retained credits conducted by the AER in the WACC review (see section 9.5.1.2) is likely to be conservative as it is discounting a

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[631] Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, p. 6, confidential.

[632] J. C. Handley, *RE: Advice on gamma in relation to the 2010-2015 QLD/SA electricity distribution determinations, Memorandum to the AER*, 20 October 2009, p. 8. An example of this issue would be where a subsidiary company which pays $100 million in tax and generates imputation credits of this amount. These imputation credits are then passed up the chain of ownership to its parent company, which also records the $100 million imputation credits, and then pays the imputation credits out to shareholders. The ATO records record this as $200 million of imputation credits, effectively double counting the amount of imputation credits generated (and therefore halving the payout ratio based on the Synergies methodology). Further, this problem is exacerbated by longer chains of company ownership.

[633] Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, p. 7, confidential.

greater proportion of created imputation credits than is needed (likely to be less than 29 per cent)[634] and therefore overestimates the decay in value

- if time decay is accounted for in a payout ratio measure which excludes the double counting of imputation credits created, it is likely that the payout ratio would be higher than 91 per cent.

Theta inferred by tax statistics

The AER notes that not only is Synergies' payout ratio affected by double counting but also the theta estimates may be affected by this issue. The AER notes that the same imputation credit being double counted may be only be used by one investor, which would therefore potentially reduce the estimated theta.

Further, the AER observes that the methodology used by Synergies to derive a theta of 0.35 varied in other ways from the approach taken in the 2008 Handley and Maheswaran study. The AER notes Synergies:

- appeared to ignore the approach taken in the Handley and Maheswaran study to calculate the amount of credits claimed by funds
- excluded non-residents from its analysis, noting that only Australian residents for taxation purposes can claim credits[635], while Handley and Maheswaran note that there are different types of non-residents (a proportion of which can claim tax credits due to inter-country arrangements).[636]

The AER observes that these methodological differences between the two studies result in a material differences in outcomes. By ignoring the number of imputation credits utilised by non-residents and funds, and the impact of double counting in the company tax statistics, the Synergies advice provided a theta estimate of 0.35 compared to 0.74 adopted in the WACC review.[637]

Gamma inferred from the Synergies advice

Synergies provided a gamma estimate by multiplying the payout ratio of 66 per cent by a theta estimate of 0.35, which results in a gamma inferred by tax statistics of 0.23. In examining Synergies' advice, Handley noted the following problems:[638]

- Synergies provided an implausibly low estimate, particularly considering that imputation credits have been refundable to resident individuals, super funds and certain other entities since 1 July 2007

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634 This figure is obtained by taking the inverse value of the payout ratio of 71 per cent (100 – 71 per cent).

635 Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, p. 7, confidential.

636 J. C. Handley, *A measure of the efficacy of the Australian imputation tax system*, The economic record, Vol. 84, No. 264, March 2008, p. 84.

637 AER, *Final decision*, *WACC parameters,* May 2009, p. 456.

638 J. C. Handley, *RE: Advice on gamma in relation to the 2010-2015 QLD/SA electricity distribution determinations, Memorandum to the AER*, 20 October 2009, p. 7.

- in estimating imputation credits used by funds, the Synergies advice had solely used credits received directly in the form of franked dividends but have not included credits received indirectly as part of a distribution from a partnership or trust. This explains the difference in the estimates for the two overlapping years of 2003 and 2004.

The AER considers it cannot rely upon the estimate of gamma provided by Synergies. The AER notes that the gamma estimate inferred by Synergies:

- overestimated the total number of imputation credits created (due to double counting in the company tax statistics)
- applied a payout ratio of 66 per cent and assumed that retained credits have no value
- underestimated the total number of imputation credits utilised.

The AER considers that adopting a gamma on the basis of Synergies' advice would not result in an outcome that achieves the Revenue and pricing principles, such as providing effective incentives in order to promote economic efficiency.[639]

The AER considers that the methodology provided by the 2008 Handley and Maheswaran study provides a relevant and reliable estimate of theta in the post 2000 period. The methodology used by Synergies suffers from numerous flaws (as identified above) and therefore the gamma estimated from this advice is unreliable.

9.5.1.4 Selection of gamma from a reasonable range

Although the Qld DNSPs appear to follow the AER's approach to selecting a value from a range of estimates they considered reasonable, the range of values has been selected based upon Synergies' advice (0 to 0.2) and not the range used in the WACC review (0.57 to 0.74).

Statement of regulatory intent

In determining a value for gamma in the SORI, the AER:

- assumed a payout ratio of 100 per cent
- relied upon two approaches in estimating to inform the reasonable range of empirical estimates of theta. These were dividend drop-off studies and studies which examined tax statistics.

With respect to dividend drop-off studies, the AER considered all of the material before it on the empirical estimates, and concluded that a reasonable and reliable estimate of theta inferred from market prices is 0.57, taken from the published Beggs and Skeels 2006 study.[640]

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[639] NEL, Part 1, section 7A.
[640] AER, *Final decision*, *WACC parameters,* May 2009, pp. 446–447.

The AER concluded that a reasonable range of theta estimated from tax statistics is 0.67 to 0.81 for the post-2000 period. Selecting the mid–point gave a point estimate for theta derived from tax statistics of 0.74.[641]

Based on the available evidence the AER took an average of the mid–point (0.74) derived from tax statistics and the point estimate from the dividend drop-off study (0.57) and rounded the value to the nearest 0.05. This calculation resulted in a value of 0.65. The AER considered that a reasonable estimate of the 'assumed utilisation of imputation credits' is 0.65.[642]

Qld DNSPs regulatory proposals

Energex stated, if the AER's framework is applied, it would use:[643]

- a lower bound of 0 based upon the Joint Industry Associations' advice
- an upper bound of 0.35 based upon tax statistics and a payout ratio of 100 per cent.

Based on this range Energex stated a gamma estimate of 0.2 is more appropriate.[644]

Based upon Synergies' advice, Ergon Energy contended that a range between 0 and 0.2 is a more reasonable and plausible range for gamma.[645] Ergon Energy proposed a gamma of 0.2.[646]

Synergies raised the following issues:[647]

- the Handley advice in the WACC review concluded that a reasonable estimate for gamma is within the range of 0.3 to 0.7 and, therefore, does not support the notion that a definitive value for gamma can now be determined
- a range between 0 and 0.2 is a more reasonable and plausible value for gamma.

AER considerations

Synergies essentially contrasts the AER's position in the WACC review with the advice the AER received from Handley, questioning why the AER selected a specific gamma. The AER notes Synergies appeared to suggest that the SORI should provide a reasonable range rather than an actual value for gamma.

The AER notes that Handley's range was based upon analysis which considered the dividend drop-off study conducted by the Strategic Finance Group (SFG). The AER considered that more weight should be given to the Beggs and Skeels study and the

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641 AER, *Final decision*, *WACC parameters,* May 2009, p. 455.
642 AER, *Final decision*, *WACC parameters,* May 2009, p. 455.
643 Energex, *Regulatory proposal*, July 2009, p. 243.
644 Energex, *Regulatory proposal*, July 2009, p. 243.
645 Ergon Energy, *Regulatory proposal*, July 2009, p. 389.
646 Ergon Energy, *Regulatory proposal*, July 2009, p. 389.
647 Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009, pp. 4–8, confidential.

AER's reasons for this can be found in the draft decision for ETSA Utilities.[648] The AER considers, in any event, the proposition that the AER can specify an acceptable range for gamma from which the DNSPs select a value (instead of the AER specifying a value) would appear to be inconsistent with the NER.

The AER also notes the Qld DNSPs refer to upper and lower bounds in their regulatory proposals based upon the terminology used in the WACC review. The AER also has acknowledged in its draft decision for ETSA Utilities that the use of terminology of upper and lower bounds is inappropriate. Rather, the AER's methodology involves identification of a reasonable range of estimates and then the selection of a point estimate within this range, rather than setting an upper and lower bound.[649]

9.5.1.5 Conclusions on gamma

The AER considers Qld DNSPs' regulatory proposals and the information provided in support of Qld DNSPs' regulatory proposals do not constitute persuasive evidence for justifying a departure from a gamma of 0.65. In forming its view the AER has considered the information provided by interested parties in response to the gamma determined in the SORI and assessed it against the underlying criteria. In summary, the AER's conclusions are:

- the Qld DNSPs have not specified any clear arguments justifying a departure from the AER's approach for determining gamma in the SORI
- Synergies' arguments regarding the payout ratio are based on an unrealistic assumption about undistributed imputation credits, and do not address the AER's findings in the WACC review regarding maintaining simplicity, and consistency with the PTRM and the Officer (perpetuity) framework
- Synergies' conclusions regarding its examination of tax statistics are unreliable due to methodological flaws
- the terminology used to present the Qld DNSPs' gamma, regarding upper and lower bound estimates, reflects the improper use of terminology in the WACC review, which the AER has now clarified.

9.5.2 Tax asset bases

The AER requested each of the Qld DNSPs to present their respective tax asset bases for RAB and non-RAB components for each year since the commencement of the NTER. The assessment of the tax asset base over this period (as opposed to a single point in time) was intended to ensure that:

- the proposed tax asset base reflects the underlying regulatory assets and consistent with regulatory determinations over the period

648 AER, *Draft decision*, *South Australia draft distribution determination*, pp. 271–272.
649 AER, *Draft decision*, *South Australia draft distribution determination*, p. 273.

- there were no transfers of tax assets to other non-regulated business units or related entities.

Consultants review

The AER sought the assistance of McGrathNicol Corporate Advisory (McGrathNicol) to assess the proposals with respect to:

- identifying an appropriate starting point to establish the tax asset base
- reviewing historical depreciation and tax depreciation assumptions
- the treatment of past additions and disposals
- the treatment of depreciation on capital contributions
- the assumptions used to split assets between standard control services, alternative control services and unregulated services
- the treatment of work in progress
- treatment of tax losses.

Energex

McGrathNicol found that, based on the information provided, Energex's proposed methodology for calculation of its tax asset base appeared reasonable.[650] McGrathNicol also noted that tax asset values were generally verifiable through supporting registers, tax working papers and other documentation.[651]

In summary, McGrathNicol noted that Energex:[652]

- established its opening asset base using the most recent NTER tax return to the ATO (year ending 30 June 2008)
- determined a tax asset base applying written down values
- derived tax asset values from asset registers, tax working papers and other supporting documentation and that the standard tax and remaining tax life inputs to the PTRM were consistent with relevant source material
- treated past additions based on actual capex in a manner consistent with generally accepted accounting principles

650 McGrathNicol, *Assessment of Energex's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 23 September 2009, p. 9.

651 McGrathNicol, *Assessment of Energex's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 23 September 2009, p. 9.

652 McGrathNicol, *Assessment of Energex's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 23 September 2009, pp. 4–9.

- included capital contributions in its tax asset base and treated depreciation on contributed assets consistent with standard control services
- had applied an appropriate method to separate RAB and non-RAB components
- had appropriately not included work in progress in its opening tax asset base for the next regulatory control period.

Ergon Energy

McGrathNicol found that, based on the information provided, Ergon Energy's proposed methodology for calculation of its tax asset base appeared reasonable.[653] McGrathNicol also noted that tax asset values were generally verifiable through supporting registers, tax working papers and other documentation.[654]

In summary, McGrathNicol noted that Ergon Energy:[655]

- had established its opening tax asset base using the RAB as at 1 July 2005. This was considered appropriate because it represented the start of the current regulatory control period and that a separate tax asset register had been maintained where these assets (and additions) had been depreciated at the tax depreciation rates set by the ATO
- had proposed a tax asset base that was significantly higher than the base contained in its ATO NTER asset valuation. This was considered appropriate because the higher tax asset base included costs (such as labour costs and overheads associated with the construction of network assets) that should be reflected in capex if network assets are to be fully costed
- derived tax asset values from asset registers, tax working papers and other supporting documentation and that the standard tax and remaining tax life inputs to the PTRM were consistent with relevant source material
- treated past additions based on actual capex in a manner consistent with generally accepted accounting principles
- included capital contributions in its tax asset base and treated depreciation on contributed assets consistent with standard control services
- had applied an appropriate method to separate RAB and non–RAB components
- had appropriately not included work in progress in its opening tax asset base for the next regulatory control period.

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653 McGrathNicol, *Assessment of Ergon Energy's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 29 September 2009, p. 10.

654 McGrathNicol, *Assessment of Ergon Energy's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 29 September 2009, pp. 4–10.

655 McGrathNicol, *Assessment of Ergon Energy's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 29 September 2009, pp. 4–10.

AER considerations

Under clause 6.5.3(2) of the NER, the Qld DNSPs' estimated tax depreciation must be the same as that used for tax purposes. To achieve this outcome, requires:

- the tax asset values of the RAB assets to be consistent with those used for tax purposes, and
- the tax standard lives and tax remaining lives of the RAB assets to be consistent with those used for tax purposes.

Following consideration of McGrathNicol's assessment and findings regarding the Qld DNSPs' tax proposals, the AER considers that these proposals demonstrate that the values of the Qld DNSPs' proposed tax asset bases reflect tax values associated with their RAB assets and that the proposed tax remaining lives and tax standard lives are reflect of the tax lives of their RAB assets.

The AER notes the point made by the EUAA regarding the recipient of tax receipts. Under clause 6.5.3(1) of the NER, the tax allowance must reflect the costs of a benchmark efficient entity. In achieving this objective, the AER considers that ownership is irrelevant, as tax is a liability that is incurred by both government and privately owned businesses.

9.6 AER conclusion

The AER considers there is no persuasive evidence for justifying a departure from a gamma of 0.65 per cent as set in the SORI. The Qld DNSPs have not demonstrated that, in light of the underlying criteria, a material change in circumstances since the date of the SORI, or any other relevant factor now makes a gamma of 0.65 set in the SORI inappropriate.

The AER considers a gamma of 0.2, as proposed by the Qld DNSPs:

- would result in a rate of return above that of 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
- would not achieve an outcome that is consistent with the national electricity objective.

In accordance with the underlying criteria, the AER considers that a gamma of 0.65:

- is supported by the most recent available and reliable empirical evidence
- generates a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services
- achieves the revenue and pricing principles, which include:
  - together with values, methods and a credit rating for the other WACC parameters, providing a service provider with a reasonable opportunity to

recover at least the efficient costs and effective incentives for efficient investment

- having regard to the economic costs and risks of under and over investment

- achieves an outcome that is consistent with and is likely to contribute to the national electricity objective.

Based on the findings of McGrathNicol, the AER considers that the tax inputs into the Qld DNSPs' PTRM and RFM are consistent with the tax provisions of the NER.

The allowances for corporate income tax determined by the AER are presented in table 9.3. These figures are calculated using the PTRM and based on the tax inputs discussed above.

Table 9.3: AER conclusion on corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	32.2	35.5	39.1	43.0	45.9	195.7
Ergon Energy	0.0	20.1	29.3	34.0	33.1	116.5

Note: Ergon Energy has no tax allowance for 2010–11 due to the carry forward of tax losses from previous years.

9.7 AER draft decision

In accordance with clause 6.12.1(7) of the NER the estimated cost of corporate tax to Energex for each regulatory year of the next regulatory control period is as specified in table 9.3 of this draft decision.

In accordance with clause 6.12.1(7) of the NER the estimated cost of corporate tax to Ergon Energy for each regulatory year of the next regulatory control period is as specified in table 9.3 of this draft decision.

10 Depreciation

10.1 Introduction

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). It also sets out the AER's assessment of the Qld DNSPs' proposed asset lives used to calculate their depreciation schedules for the next regulatory control period.

Regulatory depreciation is used to model the nominal asset values over the regulatory control period and provides the depreciation allowance in the annual revenue requirement. 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 life. Regulatory practice has been to assign a regulatory life (standard life) to each category of assets that equals its expected economic life.

10.2 Regulatory requirements

Under clause 6.12.1(8) of the NER, the AER must make a decision on whether depreciation for establishing the RAB as at the commencement of the regulatory control period is to be based on actual or forecast capital expenditure. In practice this involves a decision whether or not to approve the depreciation schedules submitted by a DNSP.

Clause 6.5.5 of the NER sets out the requirement for depreciation for each regulatory year. Clause 6.5.5(a) 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 that 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.

To the extent that a DNSP's building block proposal does not comply with the above requirements, clause 6.5.5(a)(2)(ii) of the NER provides for the AER to determine the depreciation schedules.

10.3 Queensland DNSP regulatory proposals

The Qld DNSPs proposed a straight–line approach to calculating depreciation in the post–tax revenue model (PTRM). The regulatory depreciation allowances proposed by the Qld DNSPs for the next regulatory control period are set out in table 10.1.

Table 10.1: Qld DNSPs proposed regulatory depreciation allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	87.1	96.4	108.0	119.5	120.6	531.6
Ergon Energy	103.4	116.8	113.7	130.5	134.3	598.6

Source: Energex, *Regulatory proposal*, July 2009, p. 233; and Ergon Energy, *Regulatory proposal*, July 2009, p. 366.

10.4 Submissions

No submissions were received on the Qld DNSPs' calculations of depreciation.

10.5 Issues and AER considerations

The allowance for regulatory depreciation is an output of the PTRM rather than an input to be specified or proposed by the DNSP. The relevant inputs to the PTRM's calculation of an allowance for regulatory depreciation include:[656]

- remaining life for each asset class
- standard life for each asset class
- existing assets (opening RAB) and new asset values (forecast capex) for each asset class.[657]

The AER has assessed these inputs with regard to the requirements of clause 6.5.5(b) of the NER. The AER's key considerations were whether:

- the remaining and standard asset lives (as at 1 July 2005) proposed by the Qld DNSPs and used in their roll forward models (RFMs) are consistent with those lives used by the QCA during the current regulatory control period, in accordance with clause 6.5.5(b)(3) of the NER
- the remaining lives as at the start of the next regulatory control period (1 July 2010) reflect the roll forward of the asset base over the current regulatory control period. This assessment aims to prevent over recovery of the real value of the asset as first included in the RAB, in accordance with clause 6.5.5(b)(2) of the NER
- the standard lives as at the start of the next regulatory control period (1 July 2010) reflect the economic lives of existing assets and of new assets, in accordance with clause 6.5.5(b)(1) of the NER. In most cases, the AER would expect the standard

656 Forecast inflation is also a relevant input and is discussed in chapter 11.
657 The RAB and forecast capex are discussed in chapters 5 and 7 of this draft decision respectively.

lives of the assets to not change significantly from one regulatory control period to the next, although technical developments may alter the standard lives of particular asset types of over time.

Remaining asset lives and standard asset lives

Regulatory depreciation is calculated by the PTRM on the basis of each DNSP's proposed remaining and standard asset life inputs, the opening RAB and forecast capex values.

Qld DNSP regulatory proposals

To calculate the regulatory depreciation allowances for their existing assets (by asset classes) the Qld DNSPs applied the remaining asset lives rolled forward from the start of the current regulatory control period.

In calculating the regulatory depreciation allowances for their forecast capex, both Qld DNSPs largely maintained the approach applied during the current regulatory control period. With few exceptions, their forecast capex values were allocated into the same asset classes and standard asset lives as approved by the QCA.[658] The exceptions are discussed below.

Ergon Energy also proposed that accelerated depreciation be applied to those assets destroyed by Cyclone Larry in March 2006.

AER considerations

Energex

Remaining lives
The QCA did not provide Energex with access to the models used for the 2005 determination. This meant Energex was not able to completely reconcile the remaining lives in its accounts with those used by the QCA for its 2005 determination.[659] Instead, Energex calculated the remaining lives for each asset based on the difference between the standard life of each asset and a manual assessment of how long the asset had been in service. The net book values of each asset (as contained in Energex's accounting system) and the depreciation calculated for each asset (based on the remaining life determined by Energex) were then grouped in the asset classes determined by the QCA. To work out the remaining life of each asset class, the net book values of the asset class was divided by the depreciation for that asset class.[660]

The AER reviewed the approach Energex has taken to determining the remaining lives as at 1 July 2005. The AER considers that the remaining lives proposed by Energex, while not completely reconciling with the model used by the QCA for its 2005 determination (the QCA model[661]), still meet the requirements of clause

[658] Energex, *Regulatory proposal*, July 2009, p. 235; and Ergon Energy, *Regulatory proposal*, July 2009, p. 367.
[659] Energex only received access to the QCA model when the AER made it available in October 2008. By this time, Energex was well advanced in preparing its regulatory proposal.
[660] Energex, email response AER.EGX.18, 22 September 2009, confidential.
[661] QCA, email to the AER, 3 October 2008.

6.5.5(b)(3) of the NER as the differences in the remaining lives are not significant overall.

The AER also reviewed the remaining asset lives as at 1 July 2010 proposed by Energex and found that they have been rolled forward to the start of the next regulatory control period in accordance with clause 6.5.5(b)(2) of the NER.

Standard lives

The AER notes that Energex's proposed standard asset lives for most asset categories are the same as those approved by the QCA in its 2005 determination.[662] For these asset categories the AER considers that the standard lives determined in 2005 continue to provide depreciation profiles that reflect the economic lives of these assets as required under clause 6.5.5 (b)(1) of the NER. Accordingly, the AER accepts these standard asset lives as proposed by Energex.

However, there were a number of asset categories where Energex proposed different standard asset lives than used by the QCA. In response to a query from the AER, Energex stated that the asset categories in the QCA model were done at a higher aggregation level, which meant some asset classes included assets of various types with different standard lives and that the weighting of these assets determined the average standard life for the asset class as a whole.[663] For example, distribution transformers can have a standard life of between 35–55 years depending on the particular type of transformer. If the transformer asset class is weighted more heavily with transformers of a 35 year life, the remaining life for the asset class as a whole will be closer to 35 years than 55 years.

The AER notes that the differences between the standard lives proposed by Energex and those included in the QCA model are marginal and are explained by differences in the weightings attributed to the various asset types contained in each asset category. The AER considers Energex's weightings to reflect its asset types. Therefore the AER considers the standard lives proposed by Energex meet the requirements of clause 6.5.5 (b)(3) of the NER.

Energex proposed a new asset class for 'buildings (system)' with a standard life of 60 years. This standard life significantly exceeds the 40 year standard life used by Energex for non-system buildings. The AER queried Energex on this matter, noting that Ergon Energy proposed a standard life of 40 years for both system and non-system buildings and that Energex's standard life of buildings (system) for tax purposes is 40 years.

Energex responded that buildings are normally allocated an asset life of 40 years. However, it noted that in its 2005 determination the QCA nominated a standard life of 60 years for 'substation buildings and establishment'.[664] Energex also argued that substation buildings are built to higher standards due their integration with plant and, when compared to occupied buildings, system buildings do not experience a similar rate of wear and tear, and as a general rule require less maintenance. Energex

[662] QCA, *Final Determination: Regulation of electricity distribution*, April 2005, appendix 1.
[663] Energex, email to the AER, 11 September 2009, confidential.
[664] QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 226.

therefore considered it not unreasonable to assign a standard life of 60 years to system buildings.[665] The AER has considered Energex's response and accepts the standard life of 60 years for system buildings as being consistent with clause 6.5.5 (b)(1) of the NER.

Summary

The remaining and standard asset lives approved by the AER for Energex as at 1 July 2010 are set out in table 10.2Table 10.2.

Table 10.2: AER approved remaining and standard lives for Energex (years)

Asset class	Standard life	Remaining life
System assets		
OH sub-transmission lines	51	36
UG sub-transmission cables	45	33
OH distribution lines	45	29
UG distribution cables	60	47
Distribution equipment	35	26
Substation bays	45	32
Substation establishment	58	31
Distribution substation switchgear	45	27
Zone transformers	50	41
Distribution transformers	41	30
Low voltage services	35	30
Metering	25	11
Communication – pilot wires	29	19
System buildings	60	59
System easements[a]	na	na
System land[a]	na	na
Non-system assets		
Communications	7	6
Control centre – SCADA	12	5
IT systems	5	3
Office equipment and furniture	7	7
Motor vehicles	9	6
Plant and equipment	7	4
Research and development	5	0
Buildings	40	30
Easements[a]	na	na
Land[a]	na	na

(a) These assets are not depreciated and therefore do not have asset lives.

665 Energex, email response AER.EGX.20, 25 September 2009, confidential.

Ergon Energy

Remaining lives as at 1 July 2005

Ergon Energy advised that a complete reconciliation of the asset lives used in the QCA model[666] with the asset lives in Ergon Energy's accounts was not possible as it did not have access to the QCA's model at the time of the 2005 determination.[667] Ergon Energy stated subsequent adjustments to the RAB were also made by the QCA in 2005–06 and 2006–07 resulting in the changes in the closing RAB values as at 1 July 2005. As a consequence, Ergon Energy relied on a combination of both the QCA's 2005 determination and Ergon Energy's audited regulatory statements for asset values and depreciation amounts to calculate the remaining lives for its RFM.[668]

The AER has reviewed the approach adopted by Ergon Energy and concludes that, while the remaining lives (as at 1 July 2005) proposed by Ergon Energy do not completely reconcile to the QCA model, they still meet the requirements of clause 6.5.5(b)(3) of the NER.

Remaining lives as at 1 July 2010

Ergon Energy used the RFM to determine the remaining life of the opening asset base (by asset class) as at 1 July 2010. This was done by effectively dividing the total depreciation in 2009–10 (including depreciation on capex for that year) by the closing asset values in 2009–10. Ergon Energy considered that its approach provides a necessary link between the RFM and the PTRM.[669]

The AER reviewed the remaining lives calculated by Ergon Energy and found that Ergon Energy had made an error in the way these lives were calculated. In particular, Ergon Energy had divided real depreciation figures by a nominal closing balance. This error affected all the asset classes, with some classes (Other equipment, System buildings and Land improvements) showing remaining lives that exceeded their standard lives.[670] The AER required Ergon Energy to correct this error in its modelling. The correct remaining lives are shown in table 10.3.

Standard lives

Notwithstanding two additional asset classes, the AER notes that Ergon Energy's proposed standard asset lives are the same as those approved by the QCA. It considers that these lives continue to provide depreciation profiles that reflect the economic life of those asset classes as required under clause 6.5.5 (b)(1) of the NER. Accordingly, the AER accepts these standard asset lives.

Ergon Energy introduced an additional asset class, 'Buildings (system)'. Ergon Energy proposed a standard life of 40 years for this asset class, which is consistent with the asset life for non–system buildings and the tax asset life for these assets. The AER accepts this tax asset life as being consistent with clause 6.5.5(b)(1) of the NER, notwithstanding that Ergon Energy argued for a longer standard life for this asset class, which the AER also considers consistent with clause 6.5.5(b)(1) of the NER.

666 QCA, email to the AER, 3 October 2008.
667 Ergon Energy, email to the AER, 9 September 2009, confidential.
668 Ergon Energy, email to the AER, 9 September 2009, confidential.
669 Ergon Energy, email to the AER, 9 September 2009, confidential.
670 Ergon Energy, *Regulatory proposal*, July 2009, p. 368.

Ergon Energy also introduced another asset class, ‘Land improvements’. This asset class is related to depreciable land improvements such as fencing. Ergon Energy proposed a standard life of 40 years for this asset category, which the AER considers is consistent with clause 6.5.5(b)(1) of the NER, given that the asset class buildings has a similar asset life and use.

Summary

The remaining and standard asset lives approved by the AER for Ergon Energy as at 1 July 2010 are set out in table 10.3.

Table 10.3: AER approved remaining and standard lives for Ergon Energy (years)

Asset class	Standard life	Remaining life
System assets		
Overhead sub-transmission Lines	55	34.8
Underground sub-transmission cables	45	25.0
Overhead distribution lines	50	34.8
Underground distribution cables	60	47.2
Distribution equipment	35	23.5
Substation bays	45	31.2
Substation establishment	60	31.3
Distribution substation switchgear	45	37.8
Zone transformers	50	26.4
Distribution transformers	45	22.4
Low voltage services	35	4.0
Metering	25	5.1
Communications – pilot wires	35	20.0
Generation assets	30	4.3
Other equipment	40	36.5
Control centre - SCADA	7	3.9
Land & easements (system)[a]	na	na
Buildings (system)	40	38.6
Non-system assets		
Communications	30	6.3
IT systems	5	1.7
Office equipment & furniture	7	5.2
Motor vehicles	10	7.7
Plant & equipment	10	7.4
Buildings	40	12.7
Land & easements[a]	na	na
Land improvements	40	36.3

(a) These assets are not depreciated and therefore do not have asset lives.

Accelerated depreciation for destroyed assets

Ergon Energy proposed that the assets destroyed by Cyclone Larry in March 2006 be subject to accelerated depreciation, with the remaining value of these assets as at 30 June 2010 being depreciated fully over the first year of the next regulatory control period.[671] Ergon Energy initially calculated the remaining value of these destroyed assets to be $11 million, but in response to a question from the AER revised this value to $10 million as at 1 July 2010.[672] The difference was caused by a one year delay in the assets being recorded as disposals by Ergon Energy in its accounting system.

The QCA considered a similar request from Ergon Energy as part of a pass through application for costs related to Cyclone Larry. At that time, the QCA rejected Ergon Energy's request to have those assets destroyed by Cyclone Larry subjected to accelerated depreciation. Instead, the QCA decided the assets should remain in the regulatory asset base and that Ergon Energy should continue to receive return on capital and return of capital as though the assets were still in service.[673]

However, as Ergon Energy notes in its regulatory proposal, the QCA indicated that:[674]

> The treatment of disposed assets was best determined in the overall context of the next regulatory review rather than in an ad hoc manner in responding to a cost pass-through application.

Accordingly, Ergon Energy proposed accelerated depreciation for these assets in the next regulatory control period.

The AER notes that both approaches to dealing with the destroyed assets (that is, leaving the assets in the RAB or using accelerated depreciation) will yield the same NPV outcome over the life of the assets (that is, either approach would be consistent with clause 6.5.5(b)(2) of the NER). However, the timing of the cash flows is different under each approach. If the assets are left in the RAB, Ergon Energy will recover the value of these assets over the remaining lives of the assets. Under the accelerated depreciate proposal, the value of the assets would be returned more quickly. Ergon Energy proposed a single revenue adjustment in the first year of the next regulatory control period equal to the remaining value of these destroy assets as at 1 July 2010.

The AER considers that, since the destroyed assets are no longer providing a service, it is consistent with clause 6.5.5 (b)(1) of the NER to allow these assets to be depreciated more quickly. The AER accepts Ergon Energy's proposal that the remaining value be returned in full in the first year of the next regulatory control period. The remaining value of these assets, however, should be adjusted to $10 million as at 1 July 2010, to correct for the error noted above.[675]

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671 Ergon Energy, *Regulatory proposal*, July 2009, pp. 374–376.
672 Ergon Energy, email to the AER, 4 September 2009, confidential.
673 Ergon Energy, *Regulatory proposal*, July 2009, p. 374.
674 Ergon Energy, *Regulatory proposal*, July 2009, p. 374.
675 In chapter 16 of this draft decision, $10.4 million is shown in table 16.12 reflecting the end of year value of this adjustment.

10.6 AER conclusion

The AER has assessed the remaining lives and standard lives used by the Qld DNSPs as inputs to their PTRMs, and the resulting regulatory depreciation allowance, in accordance with clause 6.5.5 of the NER.

On the basis of the AER's approved asset lives, opening RAB, and forecast capex allowance, the AER has determined the Qld DNSPs' regulatory depreciation allowances for the next regulatory control period, in accordance with clause 6.5.5(a)(2)(ii) of the NER, as set out in table 10.4Table 10.4.

Table 10.4: AER conclusion on regulatory depreciation allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	87.1	97.2	108.9	120.6	121.7	535.6
Ergon Energy	151.0	158.3	157.9	171.4	152.2	790.8

Note: These depreciation allowances include equity raising costs that are to be amortised, rather than expensed as the Qld DNSPs had proposed.
The depreciation allowance for Ergon Energy does not include its accelerated depreciation claim for destroyed assets. These assets are accounted for separately in the PTRM.

The depreciation allowances for Ergon Energy are significantly affected by the correction of the error in the remaining lives as discussed in section 10.5. The correction explains most of the increase in the depreciation allowance from that proposed by Ergon Energy.

The AER also accepts Ergon Energy's proposal for the assets destroyed by Cyclone Larry to be recovered through a revenue adjustment in the first year of the next regulatory control period.

10.7 AER draft decision

In accordance with clause 6.12.1(8) of the NER the AER has not accepted the depreciation allowances submitted by Energex. The AER has determined the depreciation allowances for Energex set out in table 10.4 of this draft decision.

In accordance with clause 6.12.1(8) of the NER the AER has not accepted the depreciation allowances submitted by Ergon Energy. The AER has determined the depreciation allowances for Ergon Energy set out in table 10.4 of this draft decision.

11 Cost of capital

11.1 Introduction

This chapter sets out the AER's calculation of the rate of return for the Qld DNSPs for the next regulatory control period. The key issues considered include the weighted average cost of capital (WACC) parameters specified in the AER's statement of regulatory intent (SORI),[676] and the determination of the risk–free rate, debt risk premium (DRP) and inflation forecast.

The AER's consideration of the corporate tax allowance, including the impact of imputation credits (gamma), is not set out in this chapter because they are not compensated for through the WACC. The analysis of corporate tax is found in chapter 9 of this draft decision.

11.2 Regulatory requirements

The AER must determine the rate of return in accordance with clause 6.5.2 of the 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.

Clause 6.5.2(b) of the NER provides that the rate of return for a DNSP is a nominal post–tax WACC calculated in accordance with the following formula:

> $WACC = k_e\ E/V + k_d\ D/V$
>
> where:
>
> k_e is the return on equity (determined using the Capital Asset Pricing Model) and is calculated as:
>
> $r_f + \beta_e \times MRP$
>
> where:
>
> r_f is the nominal risk–free rate for the regulatory control period determined in accordance with paragraph (c);
>
> β_e is the equity beta; and
>
> MRP is the market risk premium;
>
> k_d is the return on debt and is calculated as:
>
> $r_f + DRP$
>
> where:

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[676] AER, *Electricity transmission and distribution network service providers, Statement of revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009.

> DRP is the debt risk premium for the regulatory control period determined in accordance with paragraph (e);
>
> E/V is the value of equity as a proportion of the value of equity and debt, which is 1 – D/V; and
>
> D/V is the value of debt as a proportion of the value of equity and debt.

Under clause 6.5.4(a) of the NER, the AER conducted a review of the WACC parameters (WACC review).[677] The NER requirements relevant to each of these parameters are discussed below in the context of the WACC review and SORI.

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(e)(4) 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.

11.2.1 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 6.53 of the NER:[678]

- the nominal risk–free rate
- the equity beta
- 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

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[677] AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, May 2009.

[678] 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 assumed utilisation of imputation credits.

On completion of the WACC review the AER issued its SORI regarding these parameters.[679] 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 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 AER considers the underlying criteria of the SORI refer to sections and/or rules under the NER and the NEL, to which the AER relied upon to determine each particular value, method or credit rating level. While the actual criteria used are discussed below in relation to each WACC parameter, the AER also applied other general criteria set out in clause 6.5.4(e) of the NER, including:

> (1) the need for the rate of return calculated for the purposes of clause 6.5.2(b) 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 standard control services; and
>
> (2) the need for the return on debt to reflect the current cost of borrowings for comparable debt; and
>
> (3) the need for the credit rating levels or the values attributable to, or the methods of calculating, the parameters referred to in paragraph (d) that vary according to the efficiency of the Distribution Network Service Provider to be based on a benchmark efficient Distribution Network Service Provider; and
>
> (4) where the credit rating levels or the values attributable to, or the method of calculating, parameters referred to in paragraph (d) cannot be determined with certainty:
>
> > (i) the need to achieve an outcome that is consistent with the national electricity objective; and
> >
> > (ii) the need for persuasive evidence before adopting a credit rating level or a value for, or a method of calculating, that parameter that differs from the credit rating level, value or the method of calculation that has previously been adopted for it.

The national electricity objective (NEO) is defined in the NEL as:[680]

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[679] AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009.

[680] NEL, Part 1, section 7.

> 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.

As a fundamental part of the WACC review, the AER also consulted on the meaning of the term ‘persuasive evidence’, concluding that:[681]

> … persuasive evidence is likely to include objective and verifiable empirical market evidence and theoretical reasons, so long as they are well founded…
>
> …persuasive evidence refers to material which is of sufficient substance to justify a departure from the previously adopted value, method or credit rating. In order to form a view as to whether persuasive evidence exists the AER has considered all of the relevant material before it.

The AER then applied this definition as an underlying criterion to determine whether the material before it constituted persuasive evidence to depart from the previously adopted value.

The values, methods and credit rating levels determined by the AER in its SORI are listed in table 11.1 below.

Table 11.1: AER WACC parameters in the SORI

Parameter	Value
Nominal risk–free rate	10 year CGS[(a)]
Equity beta	0.80
Market risk premium	6.5%
Gearing level (Debt/Equity)	0.60
Credit rating	BBB+

Source: AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009
(a) Method used to estimate nominal risk–free rate is described below.

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

681 AER, *Final decision, WACC parameters*, May 2009, pp. 91–92.

- 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.

11.3 Qld DNSP regulatory proposals

Energex proposed a nominal WACC of 9.49 per cent, based on an indicative averaging period.[682] Ergon Energy proposed a nominal WACC of 9.49 per cent, based on an indicative averaging period.[683]

The parameters proposed by Energex and Ergon Energy are shown in table 11.2. The proposed methods, values, parameters and credit ratings are consistent with the AER’s SORI with the exception of the nominal risk–free rate.

Table 11.2: Proposed WACC parameters

Parameter	Energex	Ergon Energy	SORI
Nominal risk–free rate[a]	Yield on CGS plus 79 bps convenience yield 5.08%	Yield on CGS plus 79 bps convenience yield 5.08%	Nominal risk–free rate (no convenience yield)
Gearing level (Debt/Equity)	60:40	60:40	60:40
Market risk premium	6.50%	6.50%	6.50%
Equity beta	0.80	0.80	0.80
Credit rating level	BBB+	BBB+	BBB+
Debt risk premium[a]	3.88%	3.88%	N/A
Expected inflation rate[a]	2.45%	2.45%	N/A
Nominal vanilla WACC[a]	9.49%	9.49%	N/A

Source: Energex, *Regulatory proposal*, July 2009, p. 242; and Ergon Energy, *Regulatory proposal*, July 2009, pp. 387 and 389.
(a) Indicative only, these parameter values are to be updated in the final decision.

The AER notes Energex and Ergon Energy have not adopted the methodology for forecasting inflation—as described in the final decision for the NSW and ACT distribution determinations (see section 11.5.7).[684] The AER also notes that Energex and Ergon Energy have not adopted the AER’s methodology for estimating the return

682 Energex, *Regulatory proposal*, July 2009, p. 242.
683 Ergon Energy, *Regulatory proposal*, July 2009, p. 389.
684 AER, *Final decision, ACT DNSP*, April 2009, p. 107; and AER, *Final decision, NSW DNSPs*, April 2009, p. 236.

on debt—as described in the final decision for the NSW and ACT distribution determinations (see section 11.5.6).[685]

11.3.1 Gearing

The Qld DNSPs applied the parameter values specified in the SORI for the proportion of debt funding in their respective regulatory proposals.[686]

11.3.2 Nominal risk–free rate

The Qld DNSPs proposed a nominal risk–free rate equal to the annualised yield on nominal Commonwealth Government bonds with a maturity of 10 years plus a convenience yield of 0.79 per cent per annum. The methodology used to annualise the yield on Commonwealth Government bonds is that used by the AER in the NSW distribution determination.[687]

The Qld DNSPs stated that the return on equity provided in their regulatory proposals, due to their proposed nominal risk–free rate, is more reasonable than the return on equity based upon the methods and values used in the SORI.[688]

11.3.3 Market risk premium

The Qld DNSPs proposed a MRP of 6.5 per cent, which is consistent with the SORI. They did not consider this value to be appropriate but did not submit any additional material that had not already been considered in the WACC review.[689]

11.3.4 Equity beta

Ergon Energy and Energex proposed an equity beta of 0.8, consistent with the value specified in the SORI.[690]

11.3.5 Debt risk premium

The Qld DNSPs proposed an indicative DRP of 3.88 per cent, noting that this figure will be updated for the final determination with data from the agreed averaging period. Both accepted the use of a BBB+ credit rating and proposed that the DRP be derived from a simple average of Bloomberg and CBASpectrum fair value estimates of the cost of debt.[691]

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685 AER, *Final decision, ACT DNSP*, April 2009, p. 105; and AER, *Final decision, NSW DNSPs*, April 2009, p. 232.

686 Energex, *Regulatory proposal*, July 2009, p. 242; and Ergon Energy, *Regulatory proposal*, July 2009, pp. 242 and 388.

687 Energex, *Regulatory proposal*, July 2009, p. 240; and Ergon Energy, *Regulatory proposal*, July 2009, p. 387.

688 Energex, *Regulatory proposal*, July 2009, p. 246; and Ergon Energy, *Regulatory proposal*, July 2009, p. 389.

689 Energex, *Regulatory proposal*, July 2009, p. 242; and Ergon Energy, *Regulatory proposal*, July 2009, p. 388.

690 Energex, *Regulatory Proposal*, July 2009, p. 243 ; and Ergon Energy, *Regulatory proposal*, July 2009, p. 387.

691 Energex, *Regulatory proposal*, July 2009, p. 241; and Ergon Energy, *Regulatory proposal*, July 2009, p. 388.

11.3.6 Expected inflation

Energex and Ergon Energy proposed to use the same methodology as adopted by the AER in the NSW distribution determinations for determining the forecast inflation rate.[692]

11.4 Submissions

The submissions received by the AER on the Qld DNSPs' regulatory proposals did not comment on the cost of capital.

11.5 Issues and AER considerations

11.5.1 Gearing

Gearing is defined as the ratio of the value of debt to total capital (both debt and equity), and is used to weight the costs of debt and equity when formulating a WACC. A business's gearing, also referred to as its capital structure, will have a significant bearing on the expected required return on debt and the expected required return on equity (although notionally, it is unlikely to affect the cost of capital). The SORI specifies gearing ratio is 0.60.[693]

Regulatory Requirements

The underlying criteria used by the AER in its SORI in relation to gearing are:[694]

- the need for the rate of return to be forward looking that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services
- the need for the level of gearing to be based on a benchmark efficient DNSP
- the need to achieve an outcome that is consistent with the NEO
- the need for persuasive evidence before adopting a value or method that differs from the value or method that has previously been adopted
- 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
  - having regard to the economic costs and risks of the potential for under and over investment.

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[692] Energex, *Regulatory proposal*, July 2009, p. 242; and Ergon Energy, *Regulatory proposal*, July 2009, p. 387.
[693] AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009.
[694] NER, clause 6.5.4(e); NEL, Part 1, section 7A.

Qld DNSP regulatory proposals

The Qld DNSPs proposed to adopt the parameter values specified in the SORI for the proportion of debt funding, namely 60 per cent.

Issues and AER considerations

The gearing ratio of 60 per cent proposed by the Qld 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, and
- 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 that the Qld DNSPs' proposed value achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[695]

AER conclusion

The gearing ratio of 60 per cent proposed by the Qld DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

11.5.2 Nominal risk–free rate

The risk–free rate measures the return an investor would expect from an asset with zero default risk. The yield on long term CGS is often used as a proxy for the risk–free rate because the risk of government default on interest and debt repayments is considered to be low.

In the CAPM framework, all information used for deriving the rate of return should be as current as possible in order to achieve a forward-looking rate. While it may be theoretically correct to use the on the day rate as it represents the latest available information, this can expose the DNSP to day-to-day volatility. For this reason, an averaging method is used to minimise volatility in observed bond yields.

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[695] NER, clause 6.5.4(e).

Regulatory requirements

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.

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 calculated based upon the difference between the observed cost of debt and the nominal risk–free rate.[696]

The underlying criteria used by the AER in the WACC review relating to the nominal risk–free rate are:[697]

- the need for the rate of return to be a forward looking that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services
- the need for the return on debt to reflect the current cost of borrowings for comparable debt
- the need to achieve an outcome that is consistent with the NEO
- the need for persuasive evidence before adopting a value or method that differs from the value or method that has previously been adopted for it
- 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
    - having regard to the economic costs and risks of the potential for under and over investment.

Qld DNSP regulatory proposals

Energex contended that the GFC has had a significant impact on the market for CGS, such that their observed yield cannot be relied upon as an appropriate proxy for the nominal risk–free rate under the CAPM framework.[698] This can be demonstrated by

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696 NER, clause 6.5.2(b) and 6.5.2(e).
697 NER, clause 6.5.4(e); and NEL, Part 1, section 7A.
698 Energex, *Regulatory proposal*, July 2009, p. 240.

examining not only the risk–free rate asset in its own right but also when considering the overall reasonableness of the return on equity.[699]

Energex stated that CGS yields are not themselves biased, rather under current economic climate, observed yields underestimate the nominal risk–free rate within the context of the Sharpe CAPM. The extent of this impact, termed the 'convenience yield', has been estimated to be 79 bps by CEG. It proposed that this amount be added to the nominal risk–free rate.[700]

Energex also contended that this bias in the CGS can be demonstrated by examining the reasonableness of the estimated return on equity in its own right (assuming an equity beta of 0.8 and a MRP of 6.5 per cent).[701] Energex engaged SFG and CEG to support its regulatory proposal.

Ergon Energy proposed a nominal risk–free rate equal to the annualised yield on nominal CGS with a maturity of 10 years plus a convenience yield of 79 bps. Ergon Energy engaged CEG to support its position on the nominal risk–free rate.[702] It has also engaged SFG to support its overall position on the return on equity.[703]

Nominal risk–free rate and reasonableness of return on equity

SFG examined the plausibility of the AER's estimates against the theoretical proposition that the return on equity should always be higher than the cost of debt. SFG argued that debt holders face a lower default risk, receive fixed cash flows and have primary claims over cash flows in the event of bankruptcy when compared to equity holders. Therefore, it contended, the return on equity should be higher than the cost of debt to reflect the additional residual risks faced by equity holders.

SFG argued the estimate of the required return on equity based upon the values and methods in the SORI is actually lower than the return that debt holders are promised from a contractual fixed rate loan to the benchmark business (BBB+ rating) or even to a AA– rated institution.[704] SFG considered there are no circumstances where this could be considered reasonable or plausible given the relatively lower risk of returns to debt holders.

SFG also argued that the AER's return on equity is even more implausible for non-resident investors who could obtain an even higher relative return from providing first-ranking investment grade debt. SFG contended that, based upon the parameters, methods and values in the SORI a benchmark business could be financed entirely by equity holders who required returns that were substantially lower than the returns required by debt holders. That is, a business which solely relies upon equity finance and therefore bears no financial risks associated with debt financing and subsequently

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699 Energex, *Regulatory proposal*, July 2009, p. 240.
700 Energex, *Regulatory proposal*, July 2009, p. 240.
701 Energex, *Regulatory proposal*, July 2009, p. 240.
702 Ergon Energy, *Regulatory proposal*, July 2009, p. 387.
703 Ergon Energy, *Regulatory proposal*, July 2009, p. 389.
704 SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 1, confidential.

requires a lower return on equity. SFG noted that these conclusions also hold whether debt yields are obtained from CBASpectrum or constructed from Bloomberg data.[705]

SFG also argued the AER's proposed estimate of the required return on equity is lower than any estimate over recent decades, and is not reasonable or plausible given the effects of the global financial crisis (GFC). Specifically, SFG noted:[706]

- dividend yields are at historically high levels, and the finance literature has established a relationship between dividend yields and required return on equity
- debt spreads are at historically high levels, and the finance literature has established a relationship between debt spreads and required return on equity
- option implied volatilities are at historically high levels, and the finance literature has established a relationship between implied volatility and required return on equity
- discounted cash flow models imply high (not historically low) required returns on equity.

Convenience yield

CEG argued that CGS yields are a poor proxy for the return that investors would demand in order to induce them to invest in the equity of a business regulated under the NER (due to the GFC).[707] Specifically, CEG contended CGS yields are not representative of zero beta (zero systematic risk) assets under the CAPM. It argued current CGS yields significantly underestimate the ideal risk–free (or zero beta) rate to be used in the NER, unless you believe a business with no systematic risk could raise equity by offering a return that is 80 to 100 bps less than the yield on Commonwealth guaranteed bank debt.[708]

CEG also argued that a highly conservative estimate of the appropriate risk–free rate is equal to CGS yields plus at least 79 bps. This additional convenience yield has been calculated based on the observed difference between the yield of ANZ Government guaranteed debt with 4.7 years to maturity and CGS of a similar maturity.[709]

Averaging period

The Qld DNSPs proposed averaging periods for the nominal risk–free rate that are consistent with the method determined in the SORI—that is, they are considered to be as close as practically possible to the commencement of the regulatory control period. In accordance with clause 6.5.2(c)(2)(iii) of the NER and the SORI, the averaging period will remain confidential until after they end.

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705 SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 2, confidential.

706 SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 2, confidential.

707 CEG, *Estimating the risk free rate in the context of the NER and the global financial crisis, Report for Ergon Energy and Energex*, June 2009, p. 26, confidential.

708 CEG, *Estimating the risk free rate, report for Ergon Energy and Energex*, June 2009, p. 26, confidential.

709 CEG, *Estimating the risk free rate, report for Ergon Energy and Energex*, June 2009, p. 26, confidential.

Issues and AER considerations

Nominal risk–free rate and reasonableness of return on equity

To assess the WACC parameters, methods and values (including the return on equity parameters, methods and values) proposed by the Qld DNSPs the AER has used the underlying criteria as discussed in section 11.2.

Therefore, the AER has had regard to 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. In other words, the AER will have regard to the need for the rate of return to reflect the forward looking expectations, as at the relevant point in time. The relevant point in time is at the time of the distribution determination. The relevant period is ten years from the date of the determinations given the SORI and the DNSPs have proposed a method for the nominal risk–free rate that uses a 10-year term. Accordingly, the equity risk premium must be measured over a term consistent with the nominal risk–free rate as the CAPM examines an expected return over a pre-defined period.

The AER observes the SFG report concluded the methodologies proposed by the Qld DNSPs are more plausible than the SORI.[710] However, the AER notes that if it were to adopt SFG's approach in determining whether the Qld DNSPs' proposed return on equity was plausible and economically reasonable, the resulting analysis would fail SFG's checks. For example, the return on equity proposed by the Qld DNSPs would be 10.4 (or 10.6) per cent which only marginally outperforms a AA rated bond using CBASpectrum. Therefore, it could be argued that it would be implausible that an investor would invest in the equity side of the business (where it would have secondary claims to the debt investor) when it can issue debt at a higher rate than the return on equity.

In addition, the AER considers SFG's analysis has a number of issues which, when addressed, reduce the differences between SFG's results and the cost of debt and equity estimated using the parameters, values and methods determined in the SORI. These issues are the risk–free rate, estimation of the cost of debt and return on equity.

SFG calculation of the return on equity

The AER considers SFG marginally understates the return on equity resulting from the SORI as it incorrectly calculates the underlying risk–free rate.

The AER notes SFG compared the implied return on equity using the values and parameters as at 9 April 2009 (using a 20-day averaging period) using a nominal risk–free rate of 4.46 per cent.[711] SFG has sourced 10-year nominal risk–free rate yields directly from the Reserve Bank of Australia's (RBA) website rather than using the interpolation method as defined in the NER:[712]

> If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in paragraph (c)(2), the AER must (unless some different provision is made by a relevant statement of regulatory intent)

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710 SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 3, confidential.
711 SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 5, confidential.
712 NER, clause 6.5.2(d).

> determine the nominal risk free rate for the regulatory control period by interpolating on a straight line basis from the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date.

Based upon the date and averaging period reported by SFG and the methodology defined in the NER, the AER has calculated the nominal risk–free rate to be 4.65 per cent rather than 4.46 per cent. Using this value, the return on equity would be 9.9 per cent rather than 9.7 per cent.

SFG calculation of the cost of debt

SFG calculated the 10-year cost of debt across various credit ratings using CBASpectrum and Bloomberg fair-yield estimates. Table 11.3 summarises SFG's results.

Table 11.3: Cost of debt–summary of values reported by SFG

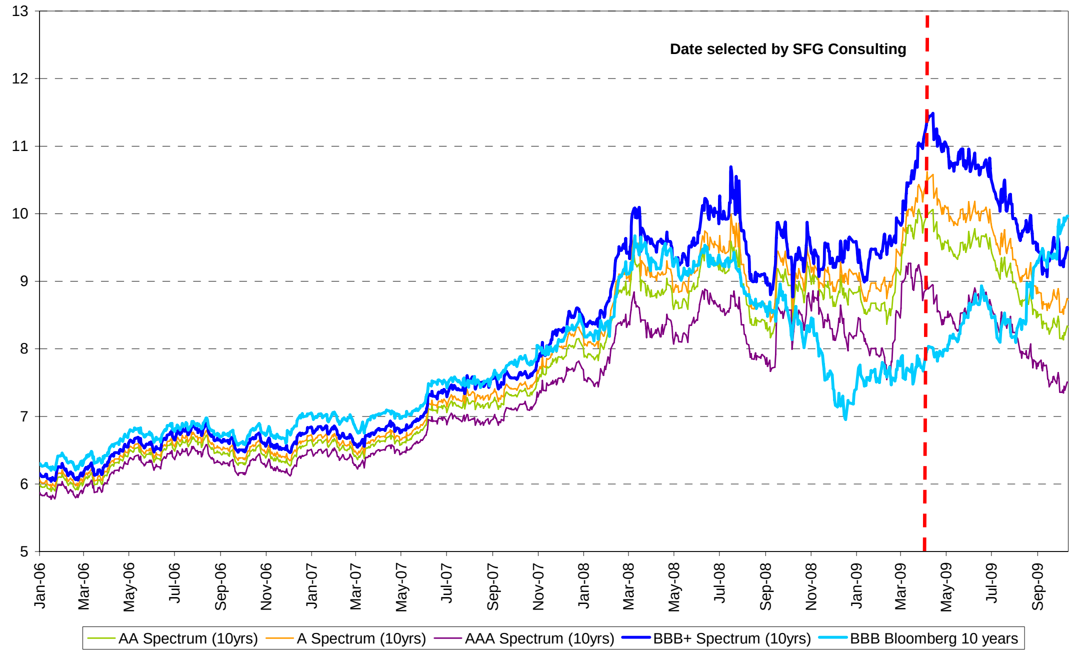
Credit rating (source)	Yield to maturity – 10 years
BBB(Bloomberg)	8.2%
AAA (CBASpectrum)	9.1%
AA (CBASpectrum)	10.3%
A (CBASpectrum)	10.8%
A- (CBASpectrum)	11.1%
BBB+ (CBASpectrum)	11.7%
BBB (CBASpectrum)	12.4%

Source: SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 13.

These data reflect a date where the cost of debt reached a historical high in the data series. Figure 11.1 demonstrates that the cost of debt on 9 April 2009 reached a historical peak and subsequent to this date the cost of debt for all benchmarks has fallen below 10 per cent. This point in time is therefore likely to exaggerate the cost of debt and can be used to demonstrate that almost any return on equity benchmarks derived by the AER are likely to be implausible and economically unreasonable. The AER also notes that 9 April 2009 is the day before the Easter long weekend. The AER considers it may be likely that this date is unlikely to be representative of normal trading conditions. Further, the AER considers the use of a moving average of the cost of debt is likely to be more appropriate than selecting when comparing it to a return on equity based upon averaged nominal risk–free rate, as this would be consistent with the approach defined under clause 6.5.2(e) under the NER.

The AER notes that the Bloomberg fair yield for BBB (BBB–, BBB and BBB+) bonds is 8.2 per cent which is lower than the return on equity of 9.9 per cent calculated in accordance with the SORI. Rather than drawing simple conclusions from these data (as does SFG) the AER considers that divergence between estimates derived using CBASpectrum and Bloomberg underlie the importance of treating information prior to and during the GFC with caution.

Figure 11.1: Time-series of cost of debt benchmarks



Source: AER analysis, CBASpectrum and Bloomberg.
Notes: Effective yields used. 10–year BBB yield for Bloomberg calculated using 7–year BBB yield and extrapolated using AAA 7–year and 10–year yields.

SFG's analysis also significantly understated the risk associated with the returns on debt it quotes in its report. SFG noted the 9.7 per cent return on equity estimated using the SORI compares to yields of 10.3 per cent on 10-year AA– rated debt where there has historically been a 99.97 per cent chance of receiving exactly the series of payments as set out in the bond contract.[713] The implied 0.03 per cent probability of default is based upon a study conducted by Elton, Gruber, Agrawal and Mann in 2001 which in turn relies upon a probability table from Standard and Poor's in 1995.[714] The AER considers the combination of current (and historically high) CBASpectrum data with probabilities of default taken from a year (1995) which pre-dates the most recent financial crisis is inconsistent and inappropriate.

The AER considers it is likely that currently observed debt premiums reflect much higher rates and probabilities of default than those observed in 1995. In particular, the AER considers it could be expected that the spread between the cost of debt and return on equity has decreased given recent market volatility. One of the main triggers of the GFC was the collapse of large institutional investors in debt markets that led to illiquidity in the debt markets and subsequently increased financial risks. A major effect of this on debt markets (relative to equity markets) was to increase the perceived default risks related to debt and decreasing the spread between the cost of debt and the return on equity.

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713 SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 14, confidential.

714 E. J. Elton, M. J. Gruber, D. Agrawal, C. Mann, *Explaining the rate spread on corporate bonds*, The Journal of Finance, Vol. 56, No. 1, February 2001, pp. 259–260.

Return on equity for non-resident equity investors

SFG contended that in a 'normal' year in which the regulated entity generates sufficient profit to earn its weighted average cost of capital, non-resident equity holders will receive a return of 7.5 per cent which is implausibly low by comparison to other investments.[715] The AER does not agree that 7.5 per cent would represent a normal year for all non-residents for several reasons.

First, SFG has not considered the relatively low nominal risk–free rate which underlies its estimate. The AER considers that for this analysis a long-run historical average would better reflect the nominal risk–free rate during a normal year. Using an average of the RBA's historical data on 10-year CGS yields from 1 July 1992 to 9 April 2009, the effective yield of the nominal risk–free rate is 6.63 per cent which results in a return on equity for a non-resident (who receives no benefit from imputation) of 9.2 per cent.[716] This can be compared to an Australian resident receiving a return on equity of 11.83 per cent in a normal year. A return of 9.2 per cent is also higher than the cost of debt estimated by Bloomberg and CBASpectrum of around 6 per cent, which rose to 8 per cent (see figure 11.1) prior to 2008 and the subsequent onset of the GFC.[717]

Second, SFG's calculation of the non-resident investor's return on equity is likely to be higher when the average benefit from the imputation credit is included. That is, not all non-residents would receive the lower return on equity due to inter-regional arrangements as considered by Handley and Maheswaran.[718] Depending on the taxation arrangements in the non-resident's country, the individual may be able to derive a benefit from the imputation credits attached to dividends through inter-regional taxation arrangements. Further, the AER considers that the return calculated by SFG may be a theoretical extreme, as non-residents may be able to capitalise the benefits of future imputation credits if the stocks owned are sold to resident investors. Therefore, the average non-resident investor's return on equity is likely to be higher when an average benefit from the imputation credit is included. That said, the AER considers adjusting for this eventuality would introduce significant complexities that would more than likely outweigh the benefits of accounting for this factor.

Third, the investor assumed in SFG's analysis may be willing to accept a lower return on equity for the purposes of portfolio diversification. That is, the volatility of returns from equity in an electricity DNSP may be lower relative to the market and therefore the investor is willing to accept a lower return on this equity. This is reflected by the equity beta of 0.8 which has been proposed by the Qld DNSPs.

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715 SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 15, confidential.

716 Return on equity for non-residents = 0.78 x (6.63 + (0.8 x 6.5)) = 9.2 per cent. RBA, *CGS - Indicative Mid Rates of Selected Commonwealth Government Securities*, Daily Statistical Release, Accessed on: 21 August 2009, <http://www.rba.gov.au/Statistics/HistoricalIndicativeMidRates/1992_to_2009.xls.>

717 Using the extrapolation method on BBB bonds, average cost of debt from 18 July 2003 to 9 April 2009 is 7.4 per cent.

718 J. C. Handley and K. Maheswaran, *A measure of the efficacy of the Australian imputation tax system*, The Economic Record, Vol. 84, No. 264, March 2008, p. 84.

Comparison of unlevered return on equity to cost of debt

SFG tested the plausibility of the return on equity calculated using the SORI by comparing the cost of debt to an investment in a hypothetical unlevered business:[719]

> The economic reasonableness of the AER's parameter values on this point can be assessed by asking whether it is likely that investors would require a return on unlevered equity of 6.5% when those same investors are being promised dramatically higher returns for lending money under contractual terms at a fixed interest rate to the (assumed) BBB+ rated benchmark firm. According to CBASpectrum, the return available on fixed-rate debt in the benchmark firm is 11.7%. According to the AER procedure for constructing the required return on debt, the return available on fixed-rate debt in the benchmark firm is 8.2%.

In summary, SFG contended that the unlevered equity provided by using the AER's approach to estimating the nominal risk–free rate (4.46 per cent), MRP of 6.5 per cent (or 6.7 per cent using the interpolation method) and an unlevered equity beta results in a return on equity which is too low, as it results in amount which is less than the cost of debt for a BBB+ rated corporate bond. The AER has a number of concerns with SFG's finding.

The AER considers, as discussed above, if SFG were to compare any measure of the return on equity to cost of debt figures on 9 April 2009, it is likely that proposed parameters, values and methods would result in the return on equity being economically unreasonable or implausible. For example, the Qld DNSPs' unlevered return on equity is 7.3 per cent (7.5 per cent using the interpolation method), which is also below the lowest cost of debt benchmark provided by SFG (8.2 per cent).[720]

The AER notes that SFG asserted that a theoretical construct (which does not reflect businesses trading on the stock exchange) is likely to provide for a specific return. Although SFG's manipulation of the CAPM formula may be correct it is merely a theoretical return and cannot be tested against the market as there is no electricity business which currently trades in the Australian stock market. The AER considers that comparing a theoretical return on equity to a cost of debt derived from yields observed in the market (rather than a theoretical cost of debt) seems inappropriate, as the theoretical return is being compared to a market observed return.

The AER also notes SFG has compared a completely unlevered business to a (BBB+) debt investment. Businesses with a credit rating of BBB+ would be exposed to a higher level of financial risk than a business that is not financed by debt. Therefore, it is unsurprising that a debt investor in BBB+ business is likely to require a higher return than an equity investor in an unlevered business. In such circumstances the debt investor would require compensation for the financial risk arising from investing in a highly leveraged business. That said, SFG acknowledged that an unlevered equity beta is likely to have less residual risk than a business with a 60 per cent geared business, but then stated there is an element of risk attached to the uncertainty in returns from equity. However, as already noted, the relative differences between the premium of the uncertain returns of equity and financial risks underlying a BBB+ rate

[719] SFG, *Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 17, confidential.

[720] This is calculated by adding the convenience yield of 79 bps to the 6.5 per cent in the SFG report.

bond cannot be tested, as there is no stock on the Australian market that matches the characteristics required to test SFG's assertion.

The AER also considers SFG has not explained why an investor willing to invest in an unlevered business would invest in BBB+ bonds. It could also be argued that such an investor would instead prefer to invest in lower risk debt instruments such as CGS or AAA rated bonds. For example, an unlevered return on equity of 6.5 per cent compares favourably to a cost of debt of 5.9 per cent for AAA yield sourced from Bloomberg.[721] The AER notes that the counterfactual to SFG's argument could be that the cost of debt from CBASpectrum on 9 April 2009 was not economically reasonable or plausible as the estimated cost of debt for AAA business exceeds the unlevered return on equity.

Given these concerns, the AER considers SFG has not demonstrated that the unlevered return on equity based upon the SORI parameters is unreasonable and implausible.

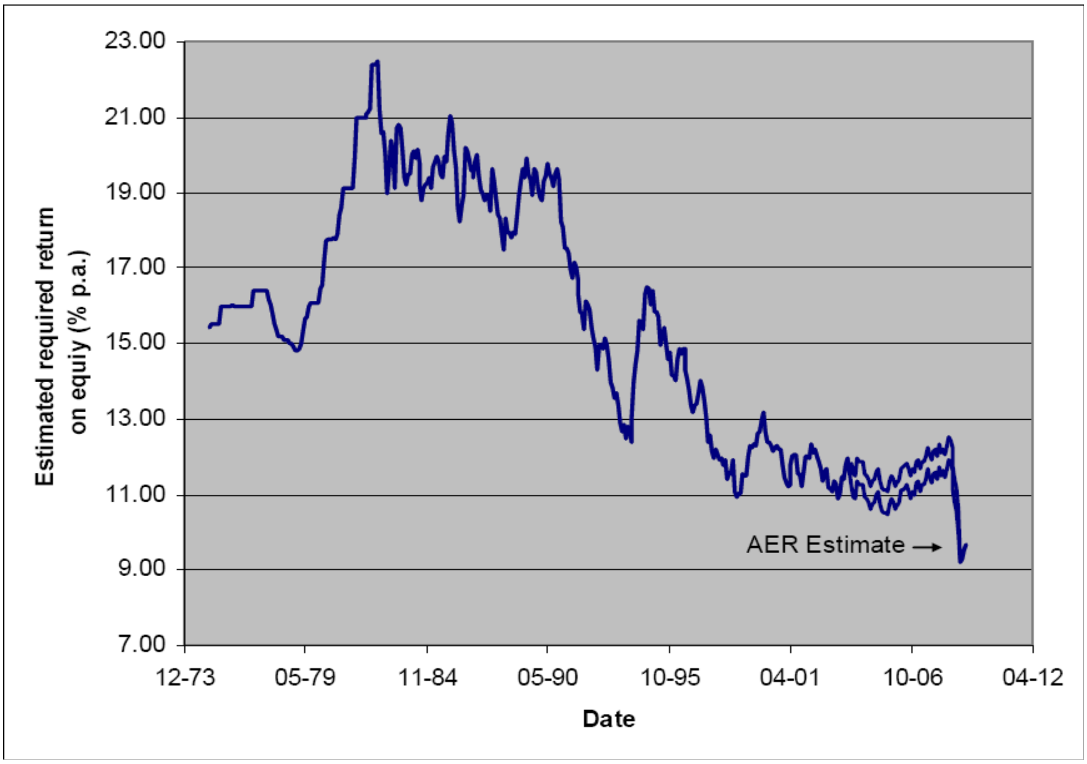
SFG historical comparisons

SFG calculated the historical return on equity for the benchmark electricity network business based upon 10-year CGS yields from January 1975 to 5 April 2009, shown in figure 11.2.

SFG's analysis implied that the SORI is the major cause of the dramatic reduction in the return on equity in approximately 2009. SFG stated that the current return on equity may be regarded as self evidently economically unreasonable and implausible given current unstable financial conditions. However, the main driver behind SFG's figure is the change in the risk–free rate (shown in figure 11.3) as this accounts for approximately half of the return on equity calculated by SFG.

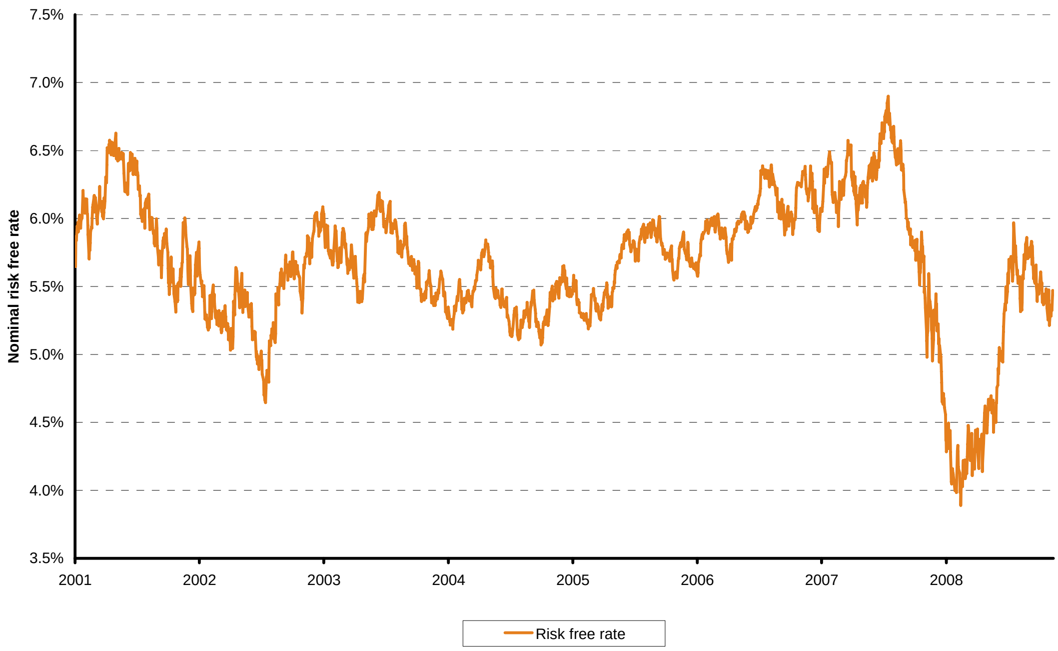
721 Yield of 5.93 per cent sourced from Bloomberg using a 20-day averaging period from 17 March 2009 to 9 April 2009.

Figure 11.2: Historical regulatory estimates of the return on equity capital for the benchmark electricity distribution and transmission firm



Source: SFG, Report prepared for Energex and Ergon Energy, 28 May 2009, p. 20, confidential.

Figure 11.3: Historical 10-year CGS yields



Source: RBA[722] and AER Analysis
Notes: CGS yield estimated using interpolation method.

[722] RBA, *CGS - Indicative Mid Rates of Selected Commonwealth Government Securities*, Daily Statistical Release, Accessed on: 14 October 2009, <http://www.rba.gov.au/Statistics/HistoricalIndicativeMidRates/1992_to_2009.xls.>.

SFG did not isolate the residual impact of the AER's decision to decrease the equity beta and increase the MRP on its calculation of the return on equity. SFG also did not investigate the roles of different decision making criteria or regulatory requirements, market conditions and information available at the time of the WACC review and prior regulatory decisions affecting these parameters.

The regulatory benchmarks for the MRP referred to in the SFG report were first determined in October 1998 by the ACCC and the Office of the Regulator General.[723] SFG did not state why it chose January 1975 as the starting point for its analysis, or how it has considered a number of events that have occurred since then that would have affected the return on equity (for example the introduction of imputation credits or the presence of capital controls prior to 1983). The AER considers that observations from around 1998 onwards are more relevant in the context of SFG's analysis. That said, the AER notes it is not clear that one set of parameters, methods and values should have been applied during this period, as market and regulatory conditions are constantly changing. For example, prior to the SORI, the previously adopted parameters, methods and values varied across jurisdictions (equity betas of 0.9 or 1.0).[724]

Prevailing market conditions
SFG examined dividend yields and implied volatilities of the equity market to give further weight to its argument that the return on equity calculated using the values and methods in the SORI is implausibly low given current market conditions. SFG's analysis related to setting the MRP rather than the equity risk premium, as it examined the equity market as a whole rather than a subset of the equity market (electricity businesses). The AER recognised the issue of the higher market volatility experienced in recent times in the WACC review. The AER addressed this issue by increasing the MRP from 6 per cent (a level which the AER considers is the long-run point of equilibrium) to 6.5 per cent. In doing so, the AER noted that dividend yields and implied volatilities are highly sensitive to short-term fluctuations in the market and generally provide a 12-month outlook of market conditions at best. To illustrate the sensitivity of estimates using these methods, the AER obtained implied volatilities of the ASX200 Index call options from 17 September 2004 to 13 October 2009. This data is shown in figure 11.4. Figure 11.4 indicates that the implied volatilities of the ASX200 Index have moved back toward historical levels (using a 20-day averaging period length).

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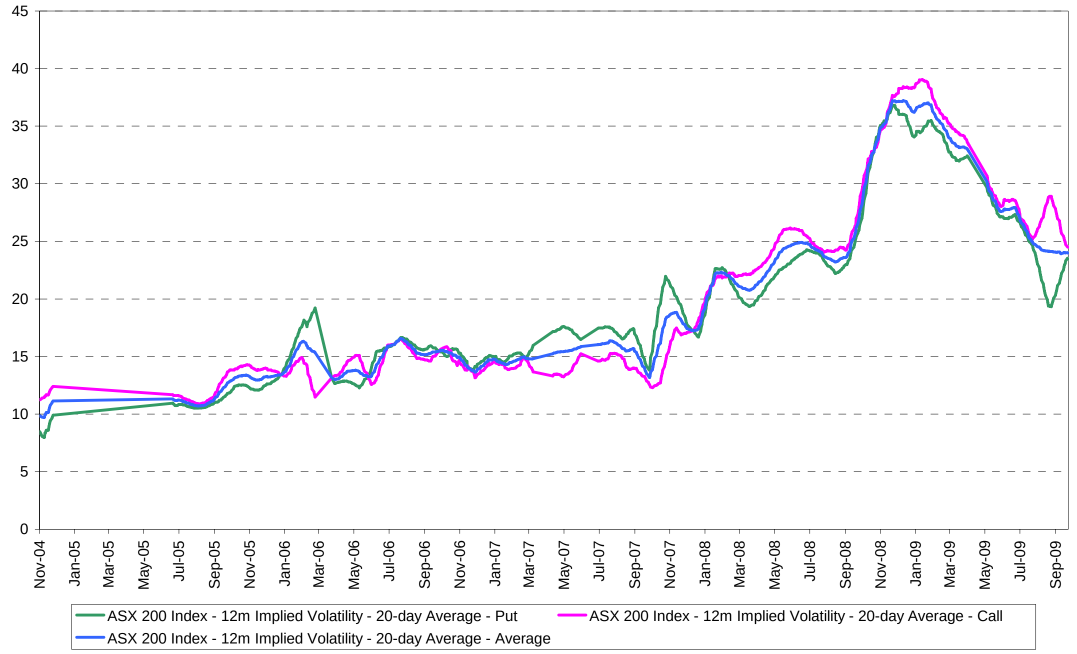
723 ACCC, Final decision, *Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System*; *Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System*; *Access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System*, 6 October 1998; and Office of the Regulator General, Final decision, *Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd*, October 1998.

724 AER, *Final decision, Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 93.

Figure 11.4: Implied volatilities ASX 200 Index options



Source: Bloomberg, AER analysis.

While still placing limited weight on these data, the AER notes that the implied volatilities appear to be returning to previous levels, indicating a MRP of 6.5 per cent is still appropriate (and even generous), as it appears the recent volatility is likely to be transitory.

SFG also noted that observed dividend yields from January 2009 are at historically high levels. As illustrated above, market conditions have changed significantly since January 2009 and therefore SFG's analysis is out of date. Further, the AER had already received this information from SFG and other interested parties in response to the AER's explanatory statement as part of the WACC review. The AER still considers that dividend yield can be highly sensitive to day-to-day fluctuations in share prices and therefore cannot be relied upon to form any definitive views on the return on equity over a 10-year period.[725]

SFG also relied upon the Competition Economists Group's (CEG) dividend growth model analysis to demonstrate the return on equity provided the values, methods and credit rating level in the SORI are unreasonable. The AER has examined CEG's analysis previously for the WACC review and in its draft distribution determination for ETSA Utilities. The AER still considers that the dividend growth model analysis cannot be relied upon as it is sensitive to a number of inputs and assumptions used to estimate the discount rate (return on equity).[726]

[725] This is illustrated by the AER's analysis as part of the WACC review. AER, *Final decision, Review of the weighted average cost of capital (WACC) parameters*, May 2009, pp. 38–41.

[726] AER, *Draft decision, South Australia draft distribution determination 2010–11 to 2014–15*, November 2009, pp. 315–318.

To support its conclusions regarding current market conditions, SFG quoted previous work conducted by CEG on the nominal risk–free rate and comments from the Organisation for Economic Co-operation and Development (OECD) on market conditions experienced in 2008. The AER has responded to the issues raised by CEG with respect to the nominal risk–free rate in section 11.3.2. The AER considers CEG has not demonstrated an approach which can reliably estimate a convenience yield, given:

- the Treasury and the RBA have already clarified their positions with respect to reliability of CGS yields to estimate the nominal risk–free rate
- the AER has a number of concerns with underlying risks of stated government issued and bank guaranteed debt when compared to CGS
- no new issues of index-linked CGS have occurred as at the time of CEG's report and therefore estimates using indexed–linked CGS are likely to be unreliable
- it is inconsistent to argue that the return on equity be adjusted for a 'liquidity premium' while at the same time not adjust the cost of debt due to a lack of liquidity, and
- financial market conditions have improved since October 2008.

The AER observes that there are now signs that markets are beginning to recover from the effects of the GFC. This is in contrast to the OECD's previous economic outlook published in late 2008 and quoted by SFG and CEG. A number of key bodies have commented on signs of recovery, such as:[727]

- the OECD in its June 2009 world economic outlook:

> Financial conditions have eased in the course of the first half of 2009. An increase in risk appetite has led to a rally in stock prices and a compression in corporate bond spreads. Money market interest rates have also fallen and securities markets have posted some signs of vitality.
>
> Nevertheless, confidence in the banking system remains depressed, and bank lending continued losing impetus in the course of the second quarter of 2009. It will take some more time for the unprecedented measures implemented so far to bear fruit and translate into a durable normalisation of financial markets.

- the RBA in its recent statement on monetary policy:[728]

> Over recent months, the value of international trade and global industrial production have both recorded modest gains after earlier large declines, and the extreme risk aversion seen earlier in the year has receded somewhat. Reflecting this, forecasts for world growth are being revised up for the first time in more than a year…

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[727] OECD, *Economic outlook* no. 85, Report, 17 June 2009, pp. 25 and 29.
[728] RBA, *Statement on monetary policy*, Statement, 7 August 2009, pp. 1 and 3.

> …This improvement in the global economy has been reflected in financial markets. Equity prices are up considerably from their lows in March when risk aversion was at its peak, and credit markets have continued to improve, with many spreads back to the levels prevailing before the failure of Lehman Brothers last year. There has also been a marked pick-up in equity and debt issuance, and banks are relying less on government guarantees to raise funding…
>
> …Given the rapidly evolving international financial and economic conditions, the outlook for the Australian economy continues to be subject to considerable uncertainty, although the risks are more balanced than they have been for some time.

It is clear from these statements and examining implied volatilities of the stock market that the levels of financial instability in the market have diminished significantly since the conditions experienced during the WACC review. It could be argued that an MRP of 6.5 per cent provided in the SORI is generous. However, although there is more evidence that the MRP is likely to return to the long-run historical levels than there is a presence of a structural break. The AER considers at this point in time, it is unlikely that circumstances have materially changed since the WACC review (four months ago) to cause the AER to return to a MRP of 6 per cent.

Regulatory considerations

The AER considers that SFG has not demonstrated that the return on equity provided for by the SORI is economically implausible and unreasonable. The AER still considers that the return on equity values, parameters and methods lead a return on equity, which is 520 bps above the prevailing 10 year CGS yields, as appropriate. The AER has identified numerous deficiencies in the analysis presented by SFG, and considers:

- in determining these methods, parameters and values for the SORI, the AER has performed or exercised its discretion in a manner that will or is likely to contribute to the achievement of the NEO[729]
- the AER also considers it has had regard to the need to achieve an outcome that is consistent with the NEO.[730]

Additionally, the AER considers the values, parameters and methods as shown in Table 11.1 are likely to lead to a regulatory return on equity that will:

- provide service providers with a reasonable opportunity to recover at least efficient costs
- provide service providers with effective incentives to invest efficiently
- are appropriate having regard to the economic costs and risks of under and over investment.

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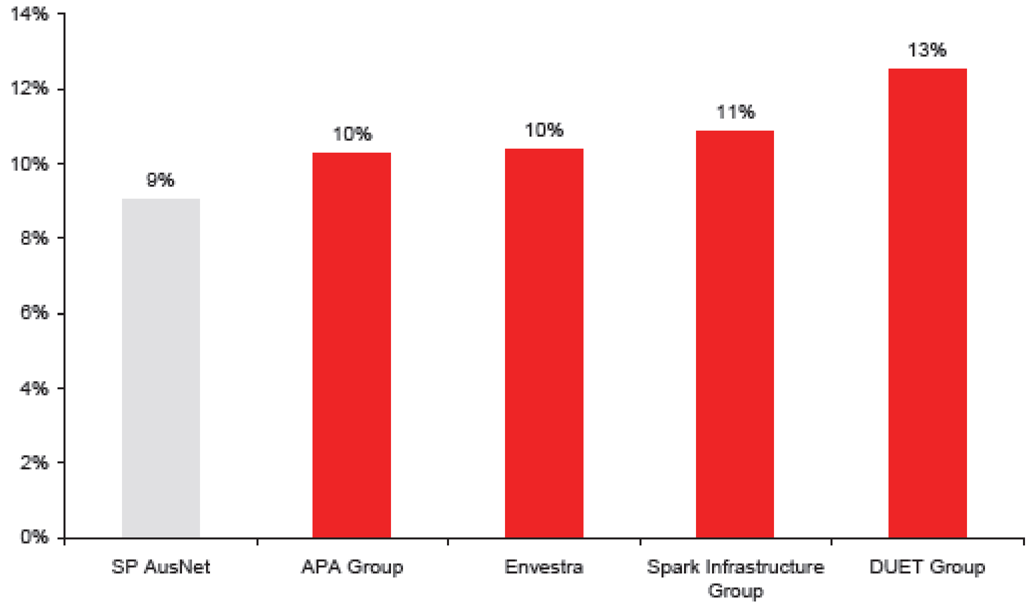
729 NEL, section 16(1)(a)

730 NER, clause 6.5.4(e)(4) and 6A.6.2(j)(4).

In this context, the AER notes that, based upon a 40-day averaging period ending 13 October 2009, that the return on equity implied by the SORI values and methods is 10.64 per cent. The AER observes that this figure sits well within investors' expectations of equity yields for regulated energy businesses.

Figure 11.5: Regulated utilities FY10 — forecast yields



Source: Macquarie Research, *SP AusNet—No surprise expected at 1H10*, 21 October 2009, p. 7.

The AER also notes that if it were to accept the proposed convenience yield of 79 basis points, the resulting return on equity would be 11.43 per cent. Based upon the above chart this would exceed expected yields for all businesses except the Diversified Utility and Energy Trust (DUET Group). The AER notes that over 50 per cent of DUET Group's carrying value of investments are either overseas activities or currently unregulated activities and therefore are likely to attract a higher return on equity than the other regulated utilities.[731] The AER also considers it is more likely that by the time of the final decision that the return on equity may increase rather than decrease due to the current economic environment resulting in increases of interest rates.

The AER considers the return on equity and its parameters reflect a forward looking long term estimate commensurate with the conditions in the market for funds that are likely to prevail over 2010 to 2020.

Convenience yield

The AER notes the information provided in CEG's report in support of the Qld DNSPs' regulatory proposals has substantively been submitted in previous processes. The AER has considered a large amount of the information as part of previous

[731] DUET, *Asset portfolio overview*, DUET Group, < http://www.duet.net.au/duet/asset-portfolio/index.html>, Accessed on: 28 October 2009.

regulatory determinations and the WACC review.[732] That said, the AER has examined issues with regard to the NER requirements such as the criteria applied to determine the method in the SORI, and the underlying criteria.[733] The key conclusions of CEG's report are:[734]

- the RBA's 2004 analysis of CGS yields, NERA Economic Consulting's (NERA) analysis of credit default swap premiums and the break-even inflation rate demonstrate that the market for CGS yields are downwardly biased or unreliable

- there have been a number of different proxies for the risk–free rate examined previously. However, in present market conditions, government guaranteed bank debt serves as the best proxy for the risk–free asset

- a conservative estimate of the bias in CGS or convenience yields under current market conditions is 79 bps. This is calculated by comparing observed yields of government guaranteed bank bonds

- government guaranteed debt yield is a better proxy for the nominal risk–free rate (risk–free asset) than rates obtained from CGS yields. CGS have experienced a flight to quality (such as to nominal and index-linked CGS), resulting in decreased yields on low risk assets more than what would normally be observed due to the GFC. This is also known as a convenience yield or liquidity premium.

The AER re-examines each of these issues below in terms of whether the information put forward represent a material change in circumstances with respect to the underlying criteria.[735]

Claims of bias in CGS yields

The ACCC has previously sought the views of both the RBA and the Treasury in response to the comments made by NERA which quoted findings from the March 2004 Financial Stability Review, and the Treasury's October 2002 discussion paper which reviewed the CGS market. The AER notes that CEG has quoted the same excerpts as NERA in its analysis. At the time, the AER sought the views of the Treasury and the RBA in response to NERA's criticisms. The Treasury stated:[736]

> …we disagree with NERA's conclusions with respect to biases existing in the *nominal* Commonwealth Government Securities (CGS) market. Following the Government's review of the CGS market in 2003, it was decided to continue issuing sufficient nominal bonds to support a well functioning market. In contrast to the index bond market the nominal CGS market continues to display the attributes of a well functioning market. Accordingly, we see no compelling reason to change the ACCC's current methodology for estimating the nominal risk–free rate.

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732 See for example, CEG, *CGS as a proxy for the risk free rate, A report for the JIA*, January 2009; and CEG, *Establishing a proxy for the risk free rate, A report for the JIA*, 17 September 2008.

733 NER, clause 6.5.4(h).

734 CEG, *Estimating the risk free rate, report for Ergon Energy and Energex*, June 2009, pp. 4, 14 and 26, confidential.

735 NER, clause 6.5.4(h).

736 The Treasury, The Treasury bond yield as a proxy for the CAPM risk–free rate, Letter to the ACCC, 7 August 2007, p. 1.

The RBA stated:[737]

> To summarise our response, the Reserve Bank does not believe there are distortions in the CGS market and hence the CGS bond yield remains the best proxy for a risk–free rate. This is not true, however, of the indexed bond market and hence this market may no longer be providing a suitable benchmark…

It is clear subsequent to making the statements cited by CEG that both the Treasury and the RBA came to the conclusion that the CGS is the best proxy for the nominal risk–free rate and disagreed with the conclusions relating to the biases in the risk–free rate at the time.

CEG also analysed the breakeven inflation rate using CGS and index-linked CGS to demonstrate the claimed recent increase in the liquidity premium (or convenience yield) on CGS.[738] CEG contended that due to the GFC there has been a flight to quality which can be illustrated by the recent reduction in spreads between different CGS (such as nominal and index-linked CGS). As such, CEG claimed that demand for all CGS has increased irrespective of whether they are index-linked or nominal CGS. The AER has previously considered similar analysis in support of the Joint Industry Association's submission in response to the explanatory statement on the WACC review. In response to CEG's analysis, the AER stated:[739]

> On this point the AER notes that it has previously determined that the yields on indexed CGS are not a reliable estimate given supply concerns in that market. The indexed CGS market is characterised by illiquidity, which has been acknowledged by the RBA in previous advice to the ACCC. The RBA stated that:
>
> The issue of insufficient supply is relevant for the indexed bond market. Turnover in the bonds is low and the market is fairly illiquid.
>
> There has been no evidence presented to suggest that the supply situation in indexed CGS markets has changed such that these yields can now be considered reliable. On this basis the AER maintains its previous view that any conclusions drawn from the indexed CGS market are questionable.

Further, the AER notes that CEG has relied upon indexed linked CGS in its analysis, yet it has advised elsewhere that indexed linked bonds cannot be relied upon to forecast inflation.[740] Although the AER considers analysis which rely on using indexed–linked CGS as unreliable rather than biased, the AER notes CEG has not demonstrated how circumstances have changed since stating it position in April 2008. Therefore, in the absence of sufficient new issues of indexed–linked CGS, the AER considers that the yields from index–linked CGS cannot be relied upon. Consequently, any analysis which attempts to show a premium or bias on nominal bonds through the use of index–linked CGS cannot be relied upon.

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737 RBA, Comments in response to report prepared by NERA, Letter to the ACCC, RBA – Financial markets group, 9 August 2007, p. 1.

738 CEG, *Estimating the risk free rate, report for Ergon Energy and Energex*, June 2009, pp. 18–19, confidential.

739 AER, *Final decision, WACC parameters*, May 2009, p. 138.

740 CEG has done this as recently as April 2008, see for example, CEG, *Expected inflation estimation methodology, Report for Country Energy*, April 2008, p. 4.

Proxies for the risk–free asset

Another type of security analysed in CEG's report in support of the Qld DNSPs' proposals are the yields of State government issued bonds. The AER has previously considered similar claims raised in support of the Joint Industry Association's submission during the WACC review.[741] The AER notes that CEG has updated this analysis by examining bonds issued by the State governments of SA, Tasmania and WA rather than the State governments of NSW, QLD and Victoria.

Similar to CEG's previous analysis, the sample uses bonds from a state which has a lower credit rating than the Commonwealth Government. Tasmania has a credit rating of AA+ since 11 October 2004 compared to the Commonwealth Government's rating of AAA. Therefore bonds issued by Tasmania would have a higher debt risk premium, reflecting the higher perceived default risk from the lower rating, and would have been affected by the GFC to a larger extent than the higher rated bonds.

The AER also considers two entities which have the same credit rating may not necessarily attract the same cost of debt. The AER notes that a credit rating only provides an indication of credit worthiness and represents a band or range rather than a precise level of credit worthiness. Therefore, the AER considers that it may be likely that the market may perceive state government debt as relatively riskier than Commonwealth Government issued debt (even if both have the same credit rating).

The Qld DNSPs and CEG suggested that, in determining the risk–free rate, CGS should not be replaced by another 'zero beta' asset. Rather, a convenience yield of 79 basis points based upon government guaranteed bank debt should be added.[742] However, by applying an adjustment of 79 bps, it could be argued that the proxy has been changed to a hybrid of 10-year CGS (defined in the SORI) bond and 5-year government guaranteed bank debt (used to derive a 79 bps adjustment to 10-year CGS). The AER considers if there is evidence that the notional risk–free asset has changed then further modifications will be required to other relevant WACC parameters (i.e. the MRP and equity beta) to ensure consistency across parameters.

As noted by the AER in the WACC review, there have been a number of different approaches to adjust CGS yields and proxies for the nominal risk–free rate suggested in recent years.[743] CEG and other consultants have examined and suggested the use of CDS and corporate bonds, bank bill swap rates, stated government debt and government guaranteed bank debt to adjust CGS yields to reflect 'best estimate' of the risk–free rate during the last three years. In other words, a new approach has been proposed by regulated businesses at least annually on average since 2007.

The AER notes that consultants have supported these approaches due to the previous approaches being discredited over a short period of time. Therefore, had the AER

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741 AER, *Final decision, Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 136.

742 Energex, *Regulatory proposal*, July 2009, p. 240 ; Ergon Energy, *Regulatory proposal*, July 2009, p. 387 ; CEG, *Estimating the risk free rate, report for Ergon Energy and Energex*, June 2009, p. 26, confidential.

743 AER, *Final decision, Review of the weighted average cost of capital (WACC) parameters*, May 2009, pp. 138–139.

accepted each new approach when it was proposed, the level of regulatory uncertainty would have been much greater than under the approach it has chosen to adopt.

The AER has noted in section 11.2 that the need to achieve an outcome that is consistent with the NEO is an underlying criterion (clause 6.5.4(e)(ii)), and one of the considerations in the WACC review, is the NEO.[744] The AER considers regulatory certainty is important factor in promoting efficient investment in the long term interests of consumers. That said, if CEG's proposed approach were considered to result in a return commensurate with regulatory and commercial risks, the AER would weigh up this consideration against other competing criteria. For example, the need for regulatory stability to provide signals that result in efficient investment against the need for the estimates relating to the WACC to reflect the best estimate of benchmark efficient costs. However, the AER considers the CEG report has not demonstrated that using an adjustment based upon government guaranteed bank debt achieves this criterion (as discussed above).

CEG suggested during the WACC review that government guaranteed bank debt can be used to adjust the CGS yield to provide a better proxy of the risk–free rate. The AER at the time rejected CEG's arguments, as the AER considered that bank debt is still likely to carry an element of default risk, not least due to the limited terms of the deposit and wholesale funding guarantees.[745] CEG responded to this comment by stating:[746]

> It is our understanding that the terms of the guarantee on wholesale funding are not limited. Rather the Commonwealth fully and irrevocably commits to pay the full value of liabilities not paid by the issuer on a guaranteed bond. The AER is correct that the guarantee scheme will be reviewed and is not anticipated to be permanent. However, because an individual bond is irrevocably guaranteed for its entire life this will not expose the buyer of that bond to any default risk.

The AER has examined the government guarantee on wholesale funding and notes the following:[747]

- for amounts greater than $1 million, the RBA attaches a monthly fee on sliding scale based upon the credit worthiness of the bank. A bank with a lower credit rating is required to pay a higher fee (from 70 to 150 bps). If the bank defaults on the monthly fee the guarantee is no longer in place
- the maximum term for government guaranteed bank debt is five years while the term of the nominal risk–free rate is ten years
- the government guaranteed bank debt is bound by the wholesale funding rules. The rules allow for legislative changes which result in the government no longer being a guarantor of the bank debt.

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744 NEL, NEL, section 16(1)(a).

745 AER, *Final decision, Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 137.

746 CEG, *Estimating the risk free rate, report for Ergon Energy and Energex*, June 2009, p. 9.

747 Australian Government, *Australian Government guarantee scheme for large deposits and wholesale funding rules*, clause 14.1.1.

The AER notes the minimum 70 bps premium attached to the guaranteed bank debt is of a similar order to the adjustment of 79 bps being proposed by CEG. Therefore it is unclear whether the 79 bps adjustment reflects a convenience yield or a pass-through of the cost of the guarantee to the market. Further, the debt being guaranteed is shorter than the term of the nominal risk–free rate and there remains an element of uncertainty attached to the guarantee due to the risk of default on the fee and legislative changes.

The AER observes that the CEG report demonstrated an element of default risk is present as two bonds which are similar in term to maturity have differences in yields (Suncorp has a premium of 89 bps compared to 70 bps Westpac's debt maturing in 2012). The AER maintains that the guarantee is transitory in nature given the government guaranteed debt was introduced to ensure confidence in the Australian banking sector at the height of the GFC, which is now beginning to subside. For these reasons, the AER considers CEG has not demonstrated how the premium attributed to a 'liquidity premium' can be separated from other factors which may increase the yield on government guaranteed debt. Further, although the 5–year debt is guaranteed by the Commonwealth Government, it is likely that the market perceives this type of security as riskier than CGS.

The AER notes that CEG has responded to Associate Professor Handley's advice regarding the liquidity premium. CEG stated in its report:[748]

> In summary, it simply doesn't matter whether one thinks of an illiquidity penalty or a liquidity premium explaining the current divergence in spreads between CGS and other assets. So long as one accepts that equity is less liquid than CGS and has liquidity that is better proxied by government guaranteed bank debt then, in a period of high liquidity premium, the latter is a better proxy than the former for the risk free rate to be used in the NER CAPM equation.

If the AER was to accept that the equity of a benchmark efficient distribution network service provider during the GFC was less liquid than CGS, then it would be equally appropriate to consider the debt being more liquid than during the GFC. As previously discussed, the GFC was driven by the collapse of debt markets. The AER notes that CEG has not advised the Qld DNSPs to reduce their cost of debt due to illiquid debt market conditions not reflecting a benchmark efficient business.

Impact of the global financial crisis on CGS yields

CEG's advice is predicated upon the impact of the GFC on financial markets highlighting market conditions experienced in October 2008. The AER observes conditions have improved since October 2008. Although financial markets have not completely recovered yet, the AER considers there are signs demonstrating the financial markets are beginning to normalise. Therefore, if the AER was to accept the presence of a convenience yield at all, it is likely this yield is transitory in nature and would be negligible in the near future.

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748 CEG, *Estimating the risk free rate, report for Ergon Energy and Energex*, June 2009, p. 23, confidential.

Proposed averaging periods

The AER has accepted the averaging periods nominated by the Qld DNSPs as it considers the period and proposed dates are in accordance with the SORI. The AER has agreed to keep the start and end dates of the averaging periods confidential until the expiration of the period as requested by the Qld DNSPs.

For this draft decision, the moving average for CGS yields with a 10-year maturity for the period ending 13 October 2009 results in a proxy nominal risk–free rate of 5.44 per cent (effective annual compounding rate). The AER will update the risk–free rate, based on the Energex and Ergon Energy's specified averaging period, at the time of its final decision.

AER conclusion

The AER considers that SFG (on behalf of the Qld DNSPs) has not demonstrated that the return on equity calculated using the values and methods in the SORI is unreasonable. In summary, the AER:

- Considers the combination of CBASpectrum data and the probabilities taken from a year which pre-dates the most recent financial crisis is likely to be unreliable to use as comparison to the return on equity. This can be demonstrated by the counterfactual of SFG's analysis that the yields estimated by CBASpectrum on 9 April 2009 are unreasonable and economically implausible by comparing an unlevered return on equity (or CGS yields) to the yield estimated for AAA bonds by CBASpectrum.

- Has a number of concerns with SFG's contention that 7.5 per cent would represent a normal year for all non-residents. The AER considers:

  - a long-run historical average would be likely to better reflect the nominal risk–free rate during a normal year

  - the return calculated by SFG in its analysis may be a theoretical extreme, as non-residents may still obtain benefits from imputation credits which would increase their return on equity

  - it could be assumed in this theoretical construct that this class of investor may be willing to accept a lower return on equity for the purposes of portfolio diversification.

- Considers SFG has not demonstrated that the unlevered return on equity based upon the SORI parameters is unreasonable and implausible.

- Considers a more robust analysis, which compares the prevailing economic conditions, the criteria on which the return on equity was set and the information available at the time, would be needed to demonstrate whether the return on equity set in the SORI was inappropriate based the NER requirements and the NEO.

- Given that the implied volatilities appear to be returning to previous levels, the AER considers the MRP of 6.5 per cent is appropriate as a measure of expected returns over the longer term, as it appears the recent volatility is likely to be short term in nature.

- Observes that recently there are early signs that markets are beginning to recover from the effects of the GFC. This is in contrast to the OECD's previous economic outlook published in late 2008 and quoted by SFG and CEG.

The AER considers the return on equity and its parameters reflect a forward looking long term estimate commensurate with the conditions in the market for funds that are likely to prevail over 2010 to 2020.

The AER considers CEG has not demonstrated the presence of a convenience yield, given:

- the Treasury and the RBA have previously stated their positions with respect to the reliability of CGS yields being used to estimate the nominal risk–free rate
- the AER has a number of concerns with underlying financial and business risks of state government issued and bank guaranteed debt when compared to CGS, which affect the debt risk premiums attached to these debt instruments
- no new issues of index linked CGS have occurred and therefore estimates using indexed linked CGS are likely to be unreliable in demonstrating whether there is a convenience yield in respect of present on nominal CGS
- it is inconsistent to argue that the return on equity be adjusted for a 'liquidity premium' while at the same time not adjust the cost of debt due to a lack of liquidity
- financial market conditions have improved since October 2008.

Therefore, the AER consider the Qld DNSPs have provided no persuasive evidence to justify a departure from the method in the SORI, when assessed against the underlying criteria. Therefore, the Qld DNSPs have not demonstrated, in the light of the underlying criteria, a material change in circumstances since the date of the SORI has occurred.

On this basis, the AER rejects the Qld DNSPs' proposed method to derive the nominal risk–free rate and considers the method proposed in the SORI achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[749]

The AER notes the Qld DNSPs' proposed averaging periods for the nominal risk–free rate that are consistent with the method determined in the SORI—that is, they are considered to be as close as practicably possible to the commencement of the regulatory control period. In accordance with clause 6.5.2(c)(2)(iii) of the NER and the SORI, the averaging periods will remain confidential but only until after the averaging periods have expired.

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749 NER, clause 6A.6.2(j) and 6.5.4(e).

11.5.3 Market risk premium

The MRP is the expected return over the risk–free rate that investors would require in order to invest in a well-diversified portfolio of risky assets. The MRP represents the risk premium investors who invest in such a portfolio can expect to earn for bearing only non-diversifiable (systematic) risk. The MRP is common to all assets in the economy and is not specific to an individual asset or business.

As part of the return on equity, the MRP is scaled up or down by the equity beta (of a particular asset or business) to reflect the risk premium—over and above the risk–free rate—equity holders would require to hold that particular risky asset or business as part of the investor's well-diversified portfolio.

Regulatory Requirements

The SORI specifies a MRP of 6.5 per cent.[750]

The AER considers the underlying criteria relating to the NER requirements that are of particular relevance to determine the MRP are:[751]

- 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
- the need to achieve an outcome that is consistent with the NEO
- the need for persuasive evidence before adopting a value or method that differs from the value or method that has previously been adopted for it.
- 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.

Qld DNSP regulatory proposals

The Qld DNSPs proposed to adopt the parameter value specified in the SORI for the MRP.

Issues and AER considerations

The MRP of 6.5 per cent proposed by the Qld DNSPs is as specified in the SORI and consistent with the NER, and is accordingly considered appropriate by the AER.

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750 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009, p. 7.

751 NER, clause 6.5.4(e) and NEL, Part 1, section 7A.

In accordance with the underlying criteria, the AER considers the proposed MRP:

- 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.[752]

AER conclusion

The MRP of 6.5 per cent proposed by the Qld DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

11.5.4 Equity beta

The equity beta measures the standardised correlation between the returns on an individual risky asset or business with that of the overall market. In essence, it represents the 'riskiness' of a business' returns compared with that of the market. Risk results from the possibility that returns will differ from expected returns (the greater the uncertainty around the returns of a business, the greater its level of risk).

As is consistent with CAPM theory and the requirements of the NER, the equity beta should only compensate service providers for exposure to non-diversifiable (systematic) risk, and not compensate for diversifiable (non-systematic) risk. Non-diversifiable risk refers to the macroeconomic or market-wide risk factors that affect the returns of all businesses in the economy—though to varying degrees—and include factors such as changes or volatility in inflation, gross domestic product growth, interest rates, commodity prices, foreign exchange rates and changes in tax laws.

The equity beta (for a particular asset or business) scales the MRP up or down to reflect the risk premium—over and above the risk–free rate—equity holders would require to hold that particular risky asset or business as part of the investor's well-diversified portfolio.

An equity beta of one implies that the business' returns have the same level of systematic risk as the overall market. An equity beta of less than one implies the business' returns are less sensitive to systematic risk than the overall market, and an equity beta greater than one implies the business' returns are more sensitive.

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752 NER, clause 6.5.4(e).

Regulatory requirements

The SORI specifies an equity beta of 0.8.[753]

The AER considers the underlying criteria relating to the NER requirements that are of particular relevance to determine the equity beta are: [754]

- 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
- the need for the level of gearing to be based on a benchmark efficient DNSP
- the need to achieve an outcome that is consistent with the NEO
- the need for persuasive evidence before adopting a value or method that differs from the value or method that has previously been adopted for it.
- 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.

Qld DNSP regulatory proposals

The Qld DNSPs proposed to adopt the parameter value specified in the SORI for the equity beta.

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, and

753 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009, p. 7.

754 NER, clause 6.5.4(e) and NEL, Part 1, section 7A.

- 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.[755]

AER conclusion

The equity beta of 0.8 proposed by the Qld DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

11.5.5 Debt risk premium

The DRP (or debt margin) is added to the nominal risk–free rate to calculate the return on debt, which is an input for calculating the WACC. The DRP is the margin above the nominal risk–free rate that a debt holder in a benchmark efficient DNSP is likely to demand as a result of issuing debt to fund the business operations. It is intended to equate to a commercial cost of debt.

The DRP varies depending on the entity's operational and financial risk as well as the term of the debt. Operational and financial risk can be combined and characterised as a credit rating. Applying the return on debt (as a percentage) to the RAB, adjusted for the assumed gearing, will generate the interest expense for regulatory purposes (also referred to as the cost of debt).

Regulatory Requirements

Clause 6.5.2(b) states that the return on debt (k_d) is calculated as:

> $k_d = r_f + DRP$
>
> Where:
>
> r_f = the nominal risk–free rate
>
> DRP = the debt risk premium for the regulatory control period determined in accordance with clause 6.5.2(e).

Clause 6.5.2(e) of the NER states that the DRP is:

> … 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 SORI defined a maturity period of 10 years in relation to clause 6.5.2(d) for the nominal risk–free rate and a credit rating of BBB+ for the credit rating level.[756] The underlying criteria used by the AER in its SORI in relation to the credit rating level were:

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755 NER, clause 6.5.4(e).

756 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, 1 May 2009, p. 7.

- the need for the rate of return to be forward looking that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services

- the need for the return on debt to reflect the current cost of borrowings for comparable debt

- the need for the credit rating level to be based on an efficient DNSP

- the need to achieve an outcome that is consistent with the NEO

- the need for persuasive evidence before adopting a credit rating level that differs from the level that has previously been adopted for it

- the relevant revenue and pricing principles, namely:[757]

  - 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

  - having regard to the economic costs and risks of the potential for under and over investment.

Qld DNSP regulatory proposals

The Qld DNSPs proposed an indicative DRP of 3.88 per cent, noting that this figure will be updated for the final determination with data from the agreed averaging period. Both accept the use of a BBB+ credit rating and proposed that the DRP be derived from a simple average of Bloomberg and CBASpectrum fair value estimates of the cost of debt.[758]

Ergon Energy argues that the AER's most recent methodology, which utilises Bloomberg estimates, has a tendency to be an underestimation of the cost of issuing benchmark 10 year BBB+ debt.[759] Further that this methodology did not 'adequately capture' the effects of the financial crisis in September 2008.[760]

Energex notes that the AER has favoured the use of Bloomberg estimates in determining the DRP in recent decisions, however believes that Bloomberg in the current climate and more generally underestimates the DRP for BBB+ corporate debt.[761] Energex also notes that there is an argument that CBASpectrum estimates can be considered a more accurate predictor, however concedes it may overestimate the

757 NEL, Part 1, section 7A.
758 Energex, *Regulatory proposal*, July 2009, p. 241 and Ergon Energy, *Regulatory proposal*, July 2009, p. 388.
759 Ergon Energy, *Regulatory proposal*, July 2009, p. 388.
760 Ergon Energy, *Regulatory proposal*, July 2009, p. 388.
761 Energex, *Regulatory proposal*, July 2009, p. 241.

DRP.[762] Hence, Energex's conservative approach is to utilise a simple average of the two.

In support of its proposal, both Ergon Energy and Energex submitted a report from the CEG.

CEG examined the relative merits of using data from Bloomberg and CBASpectrum in measuring the debt risk premium. In doing so CEG have set out general criteria in evaluating estimation methodologies, namely that such a methodology should as far as is practical: [763]

> reflect an unbiased estimate of the representative yield at the time of issue for 'typical' corporate bonds with a maturity of 10 years and a BBB+ long term credit rating from Standard & Poor's;
>
> utilise a methodology that is not unnecessarily reliant on a single or small number of observations and/or individual views but efficiently uses the totality of information available, particularly where the available information is sparse;
>
> gives rise to estimates that are consistent with standard predictions of finance theory and past empirical relationships;
>
> give rise to estimates that are consistent with current market conditions and those estimates should change as market conditions change; and
>
> be transparent including in relation to how discretion is applied. If that discretion result (sic) in yield estimates that are inconsistent with other potential proxies for the NER benchmark yield this inconsistency should be able to be explained in terms of why the alternative proxies are worse estimates for the NER benchmark yield.

CEG also listed a further 'desirable' criterion, where: [764]

> the source of the estimate would be as independent as possible from interested parties to the regulatory proceedings.

Overall CEG concluded that it would not be reasonable to place sole reliance on the Bloomberg fair value estimates for estimating the benchmark DRP, as this would: [765]

- not reflect a representative yield at the time of issue for 'typical' corporate bonds with a maturity of 10 years and a BBB+ long term credit rating. Rather, it would in effect rely almost entirely on the Bloomberg estimate of the fair value for the Santos bond

- utilise a methodology which unnecessarily relies on a single or small number of observations, and would not efficiently use the totality of information available

[762] Energex, *Regulatory proposal*, July 2009, p. 241.
[763] CEG, *Estimating the cost of 10 year BBB+ debt: A report for ETSA, Ergon and Energex*, June 2009, p. 16.
[764] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 16, confidential.
[765] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 65, confidential.

- give rise to estimates that are inconsistent with standard predictions of finance theory in that it would impose a downward sloping term structure for credit spreads

- not give rise to estimates that are consistent with current market conditions, which changed in September and October 2008

- give rise to yield estimates that are not consistent with other potential proxies for the NER benchmark yield.

Issues and AER considerations

Arguments regarding the robustness of methods employed by Bloomberg and CBA Spectrum, with respect to producing data for the DRP, have been previously raised and considered by the AER (as well as other regulators).[766] Over this time, service providers, as well as their advisors, have argued for both Bloomberg and CBA Spectrum.[767] In response to these proposals and arguments, the AER has examined the performance of estimates derived from both data sources against relevant market data.[768] This analysis has evolved to compare the fair market yields published by Bloomberg and CBASpectrum against observed yields on BBB+ rated bonds, with Bloomberg proving to better reflect observed data.

As noted in the Qld DNSPs' proposals, in recent times there has been a lack of liquidity in the market for 10 year BBB+ bonds. Therefore the AER's task of determining the DRP has become more difficult due to the lack of liquidity in the market for 10 year BBB+ bonds, resulting in a greater reliance on data published by Bloomberg and CBASpectrum. The lack of data for the purposes of determining yields on bonds with benchmark characteristics has also provided an opportunity for service providers to seek a DRP which may be higher than the "true" benchmark cost of debt.

While the methodologies utilised by Bloomberg and CBASpectrum have been subjected to scrutiny through the AER's recent review processes, the AER acknowledges that they are not completely transparent to stakeholders and this is a factor subject to current consideration by the AER, ACCC and other regulators.[769] To this end, the AER is currently investigating a more satisfactory methodology for testing and setting the DRP in the future but considers that this is a longer term goal and will not be developed in time for this determination. Therefore, at present the

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[766] See for example: ESC, *Electricity Distribution Price Review 2006–10, October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006, Final Decision Volume 1: Statement of Purpose and Reasons*, October 2006, pp. 366–372; and AER, *Directlink Joint Venturer's application for conversion and revenue cap decision*, 3 March 2006, pp. 17–18.

[767] See for example: Directlink Joint Venturer's, *Submission in response to the AER's draft decision of 8 November 2005*, 9 December 2005, pp. 22–24; and The Allen Consulting Group, *'A' rating Debt Margin differential between Bloomberg and CBA Spectrum (Memorandum)*, 23 February 2006.

[768] See for example: AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12, Draft Decision*, 8 December 2006, pp. 103–104; AER, *Directlink Joint Venturers' application for conversion and revenue cap*, Decision, 3 March 2006, pp. 211, 221; AER, *Final decision, NSW DNSPs*, April 2009, pp. 225–232.

[769] IPART, *Estimating the debt margin for the weighted average cost of capital*, May 2009.

AER relies on the fact that Bloomberg and CBASpectrum are experienced market operators who use their knowledge and expert judgement in establishing best estimates.

To supplement this, the AER has tested the outputs from Bloomberg and CBASpectrum against data relevant to the benchmark bond in determining the DRP. The AER highlights that its approach to testing the reliability of Bloomberg and CBASpectrum data, while not ideal, has been and continues to be refined in light of the arguments presented during consultation and changing market circumstances.

The following sections examine the Qld DNSPs' regulatory proposals (including CEG's report) in the context of the AER's previous considerations on this issue, specifically in regard to:

- credit rating level
- CEG's interpretation of an 'observed benchmark' corporate bond
- arguments regarding Bloomberg's and CBASpectrum's methods
- alternative methods for setting the DRP
- the AER's approach to testing Bloomberg and CBASpectrum estimates.

Credit rating level

The credit rating level of BBB+ proposed by the Qld DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

In accordance with the underlying criteria, the AER considers the proposed credit rating level of BBB+:

- is supported by the most recent available and reliable empirical evidence, which the AER considers does not support a change to the existing credit rating
- generates a forward-looking rate of return that is commensurate with prevailing conditions in the market for funds
- reflects the current cost of borrowings for comparable debt
- is a credit level based on an efficient DNSP
- 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 that its proposed credit rating of BBB+ achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[770]

Interpretation of 'observed' and 'benchmark' bond

CEG examined the relative merits of using data from Bloomberg and CBASpectrum using the criteria discussed above. In doing so it makes the following observations about the terms used in clause 6.5.2(e) of the NER, particularly in relation to the phrase 'observed annualised Australian benchmark corporate bond rate for corporate bonds': [771]

> Observed – may imply rates should reflect actual information on interest rates taken directly from the corporate bond market.
>
> …
>
> Benchmark corporate bond rate - …the term could potentially signify:
>
> > -that the "rate" to be used is to be reflective of what might be regarded as typical kind of corporate bond;
> >
> > -an "average" or "typical" cost of issuing a bond with the relevant characteristics ; and/or
> >
> > -an estimate by market participant(s) of the "average" or "typical" cost of issuing a bond with the relevant characteristics.
>
> Australian – may signify that the payments made under the bond are denominated in Australian dollars and are issued in Australia subject to Australian law.
>
> Corporate – would appear to signify bonds issued by a corporation and not by a government.

The AER notes that the terms 'observed' and 'benchmark' are not defined in the NER. However, the AER does not agree with the interpretations offered by CEG for the following reasons.

Regarding 'observed', neither annualised bond rates for Australian corporate bonds of 10 years maturity with a BBB+ rating nor a 'benchmark bond rate' are directly observed in the market as suggested by CEG. For this reason, the AER considers that the meaning of 'observed' in this context is not intended to mean directly observed but logically also captures a process of analysis or estimation, as is required.

Regarding 'benchmark', the AER considers that the 'benchmark corporate bond rate' connotes efficiency of performance and is not a bond rate that has 'typical' or 'usual' features. This interpretation accords with the use of the expression 'benchmark' as it appears elsewhere in Chapter 6 of the NER.

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770 NER, clause 6.5.4(e).

771 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 4.

The AER also considers the term ‘Australian’ as referring to corporate bonds issued in Australia by Australian privately owned businesses and not by government entities. This definition excludes bonds issued by Australian companies overseas and bonds issued by overseas companies in Australia. Further, the AER notes that to be consistent with risk–free rate, these Australian corporate bonds should be estimated using a fixed coupon bond.

The AER notes that its definition of terms in clause 6.5.2(e) of the NER has a more specific scope than that put forward by CEG. The AER considers that this subsequently undermines analysis put forward in the CEG report to the extent it relies on floating rate bonds, bonds with a ratings other than BBB+ and bonds that are not considered Australian.

Bloomberg and CBA Spectrum methodologies

A considerable section of the CEG report focuses on assessing the methodologies utilised by Bloomberg and CBASpectrum against criteria developed by CEG. Through its observations of Bloomberg output, CEG argued that the discretion and judgement of the Bloomberg methodology in generating its fair value curve creates a bias of underestimation. Against its criteria, CEG considered that the Bloomberg methodology:

- uses an unknown estimates approach in setting bond prices for calculating fair value curves which are biased towards liquid corporate bonds and therefore not representative of a ‘typical’ cost of debt[772]
- is reliant on relatively scarce or in some instances a singular observation[773], does not consider the use of bonds with other credit ratings[774] and excludes bonds that would have resulted in a higher fair value curve[775]
- is not consistent with financial theory as it creates fair value curves that across maturities that are not smooth[776], spreads to CGS that decrease for some long term maturities[777] and fair value estimates decreased as a result of the global financial crisis[778]
- does not reflect the current market conditions due to its bias toward liquid corporate bonds where the current market is ‘characterised by illiquidity’[779]
- is not transparent in its level of discretion and judgement used to create fair value curves.[780]

CEG concluded that Bloomberg’s performance against the criteria is poor and:[781]

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772 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 21–22.
773 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 23–27.
774 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 46.
775 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 20–21.
776 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 33–37.
777 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 28–31.
778 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 49–51.
779 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 22.
780 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 45.

> do not consider that sole reliance on the Bloomberg fair value estimates for estimating the benchmark rate in the NER (as per the AER methodology) is reasonable.

In contrast, CEG considered that the CBASpectrum methodology performs better against these criteria, as it:

- better reflects a 'typical' cost of debt by including both liquid and illiquid corporate bonds[782]
- relies on a broader range of observations including higher yielding bonds and bonds from other appropriate credit ratings for determining fair value curves[783]
- creates fair value curves that across maturities that are smooth and upward sloping[784] as well as fair value estimates that did increase in response to the global financial crisis[785]
- better reflects the current market conditions of illiquidity in the market through the inclusion of illiquid corporate bonds.[786]

CEG concedes the CBASpectrum methodology is similar to the Bloomberg methodology where it utilises a level of discretion and judgement in its development of fair value curves that is not transparent.[787]

Against the other 'desirable' criteria, CEG noted that both Bloomberg and CBASpectrum methodologies have advantages as they are independent to the regulatory proceedings.[788]

CEG concluded that while the CBASpectrum methodology performed better against its criteria, it too is not ideal for sole reliance in estimating the NER benchmark rate due to some evidence of overestimation and at times aberrant bond yields.[789] The AER notes that since the release of the CEG report it appears CBASpectrum has amended its methodology as peaks in the analysis of historical time series of yields have since been removed. The AER infers from this that these aberrant bond yields—which have been a point of contention in previous AER decisions—have now been rectified. CEG considered, given the choice of the two methodologies, it would give more weight to the CBASpectrum methodology over Bloomberg. Further, CEG contended that a conservative approach would be to use an average of the two, as neither methodology is consistently more accurate than the other. This is the approach the Qld DNSPs have put forward in their regulatory proposals.

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781 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 65.
782 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 46–48.
783 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 40–44, 47.
784 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 41–44, 47.
785 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 49–52.
786 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 47-48.
787 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 17-18.
788 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 66.
789 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 65-66.

The AER does not accept CEG's proposed criteria for selecting a data source to derive the benchmark DRP.[790] CEG rely heavily on assumptions about the methodology used by Bloomberg and CBASpectrum, to form a view about the appropriate information service to estimate a benchmark return on debt. Given the proprietary nature of these methods, the AER cannot verify the assumptions made by CEG regarding these methods, therefore rendering any conclusions made by CEG on such an approach as unreliable.

CEG notes that both Bloomberg and CBASpectrum utilise a considerable level of discretion and judgement in their methodologies and the processes underpinning this discretion and judgement is not extensively disclosed.[791] CEG confirms this by stating:[792]

> I do not have an in-depth understanding of the current proprietary methodology that CBASpectrum uses to estimate its fair value curves (just as I do not have an in depth knowledge of Bloomberg's proprietary method).

The AER agrees that both Bloomberg and CBASpectrum use proprietary methods which are not fully transparent. However, the AER notes that both proprietary methods have been extensively investigated by the AER over many determinations and consider that while there is not a high level of transparency and given the current lack of appropriate substitutes, both Bloomberg and CBASpectrum are respected providers of financial information which can be relied upon for analysis. The AER considers that the fact that experienced market operators use their knowledge in assembling their fair yield curves, it is possible in their methodologies that distorting or anomalous information be given a more appropriate weighting in the overall assessment.

The AER notes that conclusions drawn in a report prepared by Doctor Hird and Professor Grundy for NERA have previously suggested the use of Bloomberg fair yield estimates as more reliable than those of CBASpectrum.[793] While the AER acknowledges that there is evidence to suggest that the CBASpectrum methodology has since been refined, the AER considers that Dr Hird's previous and current analysis supports utilising a provider of financial information based on assessment of performance at a particular time and not a particular methodology. In a report considered by the AER as part of the Victorian Advanced Metering Infrastructure (AMI) determination, CEG make an interesting point: [794]

> A repeat of the 2005 methodology used by myself and Prof. Bruce Grundy to compare the accuracy of the Bloomberg and CBASpectrum fair value curves for long maturities would find that CBASpectrum was now significantly more accurate than Bloomberg.

The AER's approach to assessing the reliability of one provider over the other (or a simple average of the two) is based on a comparison of fair yield information against

790 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 16.
791 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 18.
792 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 42.
793 NERA, *Critique of Available Estimates for the Credit Spread on Corporate Bonds: A report for the ENA*, May 2005, p. 2.
794 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 61.

observed data, rather than conjecture about their respective methodologies. While the AER acknowledges this approach is not perfect and is investigating further refinement in the future, such testing is not inconsistent with the views put forth by CEG in a number of reports currently before the AER.[795] The difference between the AER's and CEG's approaches and conclusions appears to stem from the choice of market data used to undertake this assessment and the prevailing market conditions. The AER's approach to testing the reliability of Bloomberg estimates, and issues arising out of current consultation processes, are addressed below. The AER has used and refined this general approach over several regulatory determinations and notes that this has resulted in Bloomberg proving to better reflect observed data at the time.

Alternative measures of the DRP

CEG also analysed the most recent issue of the Tabcorp bond (1 April 2009) noting:[796]

> The Tabcorp bond is the best observation available of a recently traded BBB+ bond with a medium term maturity. Importantly, it is also an observation of the cost of debt to an issuer and therefore is desirable as a source of information on the NER benchmark rate…

Given the Tabcorp bond is a floating rate note, CEG notes that adjustments can be made for comparison as a fixed coupon bond. In doing so, CEG compared the Tabcorp bond against the Bloomberg and CBASpectrum methodologies. CEG concluded that while the Tabcorp bond can be 'regarded as itself an underestimation of the average BBB+ bond yield'[797] there is evidence to support that Bloomberg underestimates and CBASpectrum overestimates the NER benchmark.

The AER has addressed the appropriateness of the Tabcorp bond in the context of the AMI Final determination.[798] The Tabcorp floating rate note provides only one data sample for comparison to determine whether Bloomberg, CBASpectrum or an average of the two provides the best fair value estimate for the purposes of determining the yield on the benchmark corporate bond. The relevance of the Tabcorp bond in this respect is reduced to the extent it does not reflect many of the features of the benchmark corporate bond, in particular its maturity of 5 years and being based on a floating rate, not a fixed rate. Instead the AER considers that a comparison to a larger number of bonds that reflect the benchmark corporate bond is a better test of the accuracy of Bloomberg and CBASpectrum data. This is consistent with CEG's assessment criteria:[799]

> utilise a methodology that is not unnecessarily reliant on a single or small number of observations and/or individual views but efficiently uses the totality of information available, particularly where the available information is sparse…

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795 See CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009; CEG, *Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008*, September 2009; and CEG, *Estimating the cost of 10 year BBB+ debt: A report for ActewAGL*, June 2009.

796 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 56.

797 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 56.

798 AER, *Final determination: Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications*, pp. 126–128.

799 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 16.

In addition to the Bloomberg and CBASpectrum methodologies, CEG propose two alternative approaches. The first approach is the use of a 'custom built' methodology for the specific requirements of setting the DRP under the NER.[800] However, CEG concedes that this approach too would involve significant judgement and would be at the expense of the independency of the estimates.

The AER considers use of a custom built methodology may have some merit in the future and is currently investigating such an approach. However, this is a longer term objective and to date the AER has been satisfied that the information provided by Bloomberg and CBASpectrum satisfies the requirements of the NER. The AER uses a process of analysis to determine which provider of financial information best predicts the yields on 10 year BBB+ rated bonds.

The second approach that CEG briefly mention would be to use an estimate based entirely on the Tabcorp floating rate note DRP (adjusted to fixed term).[801] The AER's concerns over placing sole reliance on the Tabcorp bond are discussed above.

AER approach to testing Bloomberg and CBA Spectrum estimates

The CEG report raised issues from the AER's New South Wales final distribution determination[802] regarding what it believes are factual errors as well as methodological flaws in the AER's test of accuracy between the Bloomberg and CBASpectrum fair value estimates.[803] The factual errors raised by CEG include:[804]

- references to Bloomberg quoted prices reflecting actual trades
- the imposed condition that fair value curves for different ratings do not cross were only applied by CBASpectrum
- the AER's failure to decipher that in March 2009 the CBASpectrum still had a credit rating of A– for the Babcock and Brown Infrastructure (BBI) bond although it was re-rated by Standard and Poor's in June 2008 and was stored in the CBASpectrum data base as BBB+ rated bond.

The AER notes these issues raised by CEG but considers that they do not affect the AER's approach to comparing the Bloomberg and CBASpectrum fair value curves with observed bond yields nor the conclusions reached in the AER's recent electricity determinations. For example, the AER acknowledges that a different approach of investigating the credit rating of bonds in CBASpectrum's database would have uncovered that the BBI bond was in fact rated at BBB+. However, the AER notes that its incorrect reference of the CBASpectrum database not being up to date in respect of the BBB+ credit rating of the BBI bond was only one factor for its exclusion from the sample of corporate bonds in the AER's recent electricity determinations. The AER considered the need to take account of the perceived credit rating by the market of the BBI bond. This matter is further discussed below, as part of the AER updating its

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[800] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 66.
[801] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 66.
[802] AER, *Final Decision, NSW DNSPs*, 28 April 2009.
[803] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 63.
[804] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 63.

analysis on which fair value curve is appropriate to adopt for the purposes of determining the benchmark debt risk premium for this draft decision.

The methodological flaws raised by CEG include that the process of analysis undertaken by the AER in testing the accuracy of the financial information providers were not properly constructed in that:[805]

> the tests do not measure what is important – which is the accuracy of the AER's method of deriving a 10 year BBB+ yield from Bloomberg fair value estimates against that of CBASpectrum's 10 year BBB+ fair value estimates; and
>
> the tests actually measured the accuracy of each data service's fair value estimate in predicting the yield on the lowest yielding bonds in each data service.

CEG notes that if the relevant benchmark was the lowest yielding bonds then this was not established by the AER. Further, if the lowest yielding bonds were considered the benchmark then it is to be expected that Bloomberg would be determined the most accurate in comparison.[806]

Further issues relating to methodological flaws raised by CEG include the AER's inclusion of a concept of the 'market perceived credit rating' that is at odds with the NER reference of the Standard and Poor's credit rating'.[807] CEG noted that the 'market perceived credit rating' is poorly defined and appears to be biased to exclude higher yielding bonds. CEG further noted that even through the use of the 'market perceived credit rating' concept it is not appropriate to determine that bonds with high yields (and the reverse for low yields) have a credit rating above (or below) their Standard and Poor's credit rating.[808]

As discussed above, the AER considers the outcome of the process of analysis determines which financial provider of information is the most accurate in predicting observed yields. In the New South Wales final determination the outcome of the analysis demonstrated that the Bloomberg's BBB fair value estimates was the better predictor.

Further, as discussed above, the AER considers the meaning of the term 'benchmark' in clause 6.5.2(e) of the NER connotes efficiency of performance. This interpretation of benchmark, along with the other discussed interpretations of terms in clause 6.5.2(e), provides the specific scope in which the AER's process of analysis is required to focus. That is the sample of bonds in which the AER must utilise in its analysis is restricted to Australian corporate bonds that have a 'benchmark' BBB+ rating.

Given this specific scope, the process of analysis should therefore utilise a methodology which excludes any outliers. This is an important point, as the inclusion of any outliers may contaminate the sample and provide for an outcome of analysis

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805 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009,p. 63.
806 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 64
807 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 64.
808 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 64.

that is not a 'true' reflection of benchmark BBB+ bonds. The AER only considers a bond an outlier if there is a valid reason.

In the New South Wales final determination a bond was excluded if it was considered that it had a market perceived rating that differed from the Standard and Poor's credit rating of BBB+. The AER determined that this is a valid reason. The approach taken by the AER is that the bonds utilised in the process of analysis:

- reflects the requirements of the NER and the SORI to base the benchmark on a BBB+ credit rating,
- is consistent with the benchmark nominal risk–free rate (CGS) which uses a fixed coupon.

Finally, the AER had no preconceived determinant that the lowest yielding bonds were the efficient benchmark, but rather the process of analysis determined that the sample bonds utilised in the observation were sufficiently representative of the population of benchmark BBB+ rated corporate bonds. While CEG argue this outcome to be biased toward the lowest yielding bonds and therefore subsequently biased toward the Bloomberg fair value estimates, the AER considers this outcome to be a representation of the benchmark referred to in clause 6.5.2(e) of the NER.

Previous AER analysis demonstrates that Bloomberg's BBB fair value estimates are a better predictor than CBASpectrum's BBB+ fair value estimates when compared to a sample of a number of BBB+ rated bonds.[809] The AER accordingly considers that given the current lack of appropriate alternatives, a comparison of Bloomberg's or CBASpectrum's fair value estimates with a number of observed bond yields can be used to determine which fair value curve (or a simple average of the two) provides the best possible estimate in the circumstances, including with respect to the relevant averaging period.

Consistent with the AER's previous analysis,[810] the assessment of providers of financial information has included a simple average of Bloomberg and CBASpectrum fair yield estimates in the analysis. The simple average has been included for consistency and will only be relied upon where it is found that neither Bloomberg nor CBASpectrum are a better predictor. However, in most circumstances the AER would expect that one provider would be a better predictor at any given time. As noted above, the AER will consider further refinements to its approach in setting the DRP in the future.

In conducting this comparative analysis for the Qld DNSPs, the observed yields of a common sample of BBB+ rated bonds (with a maturity of at least 2 years) from different sources are compared with the fair value estimates based on Bloomberg, CBASpectrum and an average of both. The difference between the observed yields and the fair value estimates are compared using the weighted sum of squared errors (WSSE), defined as:

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[809] AER, *Final Decision, ACT DNSP*, 28 April, pp. 99–101.

[810] AER, *Final Decision, ACT DNSP*, 28 April; and AER, *Final Decision, NSW DNSPs*, 28 April 2009.

$$WSSE = \frac{1}{n}\sum_{i=1}^{n}\left\{\left[\sum_{j=1}^{t_i}\left(Observed_{i,j} - Fair_{i,j}\right)^2\right]\frac{1}{t_i}\right\}$$

Where:

- n is the number of bonds in the sample
- t_i is the number of observations for the i^{th} bond
- $Observed_{i,j}$ is the j^{th} observed yield for the i^{th} bond, taken from either Bloomberg, CBASpectrum or UBS
- $Fair_{i,j}$ is the j^{th} fair yield for the i^{th} bond, taken from either Bloomberg or CBASpectrum.

The weighted sum of squared errors is a refinement to the measurement approaches previously used by the AER as it gives equal weight to all bonds in the sample. If the sum of squared errors is not weighted then bonds which have fewer observations will have less impact on the final calculation.

In order to conduct this analysis, the AER defines a population of bonds to observe and then selects a sample from this population. Ideally the population and sample of bonds would be the same. The AER, however, considers that some bonds from the population should be excluded if there is valid reason. The population of bonds are BBB+ rated corporate bonds issued in Australia by Australian companies with observations available from Bloomberg, CBASpectrum and UBS over the averaging period. Based on these criteria, the population of bonds are as shown in table 11.4.

Table 11.4: Population of BBB+ rated bonds

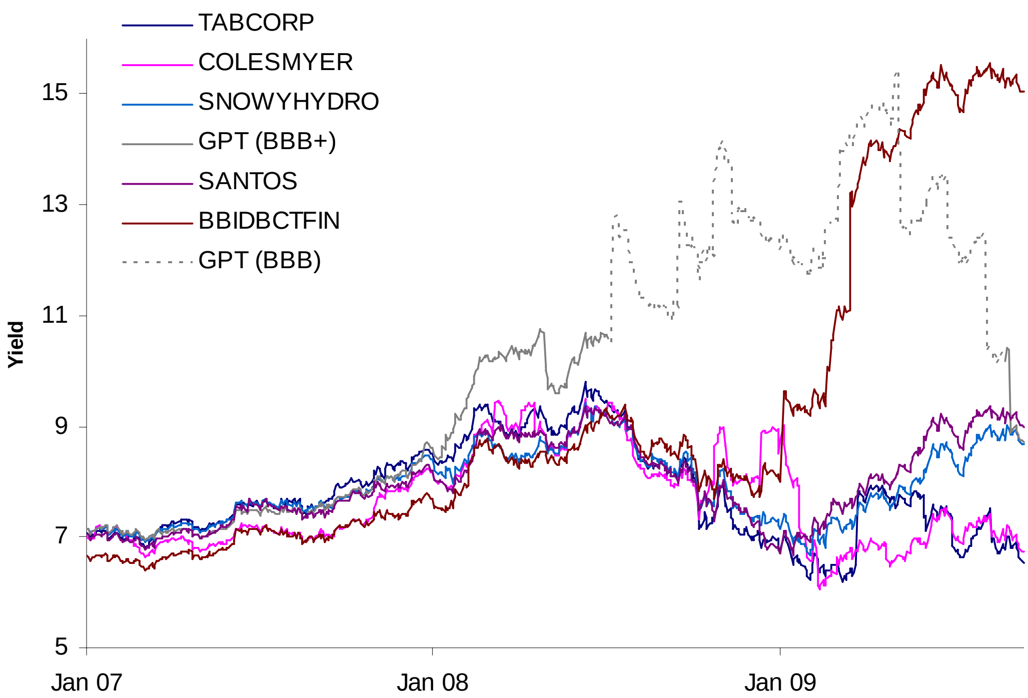
Issuer	Maturity	ISIN
Tabcorp	13 October 2011	AU300TPP0010
Coles Myer	25 July 2012	AU300CML1014
Snowy Hydro	25 February 2013	AU000SHL0034
GPT Group	22 August 2013	AU300GPTM218
Santos	23 September 2015	AU300ST50076
Babcock & Brown Infrastructure	9 June 2016	AU300BBIF018

Note: These bonds meet the following criteria: BBB+ rated corporate bonds issued in Australia by Australian companies with observations available from Bloomberg, CBASpectrum and UBS rate sheets over the averaging period. The maturities range from around two years to just under 7 years.

The AER considers that the observed yields on these bonds also reflect the credit rating perceived by market participants, not necessarily the credit rating assigned by ratings agencies. As set out in the SORI, these bonds are required to have a credit rating of BBB+. However, if the AER notes strong evidence to suggest a divergence between the market perceived credit ratings and assigned credit ratings then the bond will be excluded from the sample. This is done because where a bond is considered an outlier even though it has the assigned credit rating, its inclusion contaminates the sample and therefore is detrimental to the outcome of the process of analysis for 'true' BBB+ bonds. As companies do not seek continual review of their bonds' credit ratings, the 're-labelling' of the credit ratings is not always signalled to the market place.

Further, to the extent that a structural break in respect of the yield of a particular bond can be identified then this is strong support for a divergence between the market perceived and assigned credit rating. In such a case the yield on the bond would represent an outlier in the data set and would not represent the yield on bonds issued by an efficient benchmark firm. Figure 11.6 shows the observed yields from a population of the BBB+ bonds.

Figure 11.6: Observed yields for a population of BBB+ bonds (per cent)



Source: UBS rate sheets.

The identification of a structural break must, initially, be made on the basis of an inspection of the data. By removing the data on the GPT Group bond during the period it was re-rated to BBB, the AER considers evidence that the these periods present some indication of a structural break. This is the period leading up to the downgrade of the GPT bond in mid 2008 and the period beginning in early 2009 for the Babcock and Brown Infrastructure bond. The period leading up to the downgrade of the GPT Group bond will not be considered in the averaging period and therefore does not affect the AER analysis for this draft decision. However, the period identified as a possible structural break for the Babcock and Brown Infrastructure bond is included in the averaging period.

In the period from June 2006 to December 2008 the average observed yield on the Babcock and Brown Infrastructure bond was 7.5 per cent while in the period since January 2009 the average observed yield has been 13.3 per cent. The Chow test is commonly used to determine the existence of a structural break—it compares two time periods to determine if they have the same explanatory factors.[811] Based on a comparison of the average yields in these two periods, the Chow test supports the conclusion that these averages are not statistically the same.[812] This statistical analysis is further supported by market events occurring in late 2008 and early 2009 with the voluntary suspension of trading in Babcock and Brown shares and attempts to restructure the Babcock and Brown group. The entire group was therefore operating under abnormal conditions.[813] The analysis supports the conclusion of a structural break in the observed yields on the Babcock and Brown Infrastructure bond in early January 2009. This, combined with observations of market events, supports the conclusion of a divergence between market perceived credit rating and assigned credit rating.

As a result of this analysis, the AER considers that the Babcock and Brown Infrastructure bond should be excluded from the sample of BBB+ rated bonds that is used in the comparison of fair value curves to observed yields.

Yields were observed for the bonds listed in table 11.5 and table 11.6 over both 15 and 40 days to 13 October 2009. These yields were observed from Bloomberg, CBASpectrum and UBS.

Table 11.5: Sample of BBB+ corporate bonds—observed yields and fair values over 15 days to 13 October 2009 (per cent)

Issuer	Average observed yield			Average fair value	
	Bloomberg	CBASpectrum	UBS	Bloomberg	CBASpectrum
Tabcorp	6.8	6.8	6.6	7.6	7.1
Coles Myer	6.9	6.8	6.8	7.8	7.8
Snowy Hydro	8.9	10.4	8.9	8.1	8.1
GPT	9.0	8.8	8.9	8.3	8.4
Santos	8.8	9.0	9.1	8.9	9.0

Source: Bloomberg, CBASpectrum, UBS rate sheets and AER analysis.

811 Chow, G. C., *Tests of Equality Between Sets of Coefficients in Two Linear Regressions*, Econometrica 28(3), July 1960.

812 More specifically, the Chow test statistic is distributed according to the F distribution and the null hypothesis is that the two averages are the same. Given this data set, the observed F is 2141—this is a p–value much smaller than 0.001. This leads to the rejection of the null hypothesis, at any reasonable level of significance, and the conclusion that the averages are statistically different.

813 Babcock and Brown, *Suspension from official quotation*, 12 January 2009.

Table 11.6: Sample of BBB+ corporate bonds—observed yields and fair values over 40 days to 13 October 2009 (per cent)

Issuer	Average observed yield			Average fair value	
	Bloomberg	CBASpectrum	UBS	Bloomberg	CBASpectrum
Tabcorp	6.9	6.9	6.7	7.4	7.1
Coles Myer	7.0	6.9	6.9	7.6	7.8
Snowy Hydro	8.8	10.4	8.9	7.8	8.2
GPT	9.3	9.3	9.2	8.0	8.4
Santos	8.8	9.0	9.1	8.6	9.0

Source: Bloomberg, CBASpectrum, UBS rate sheets and AER analysis.

The AER notes that these bonds mature within six years. Ideally, the sample would also include BBB+ bonds with longer maturity dates but there are no such bonds currently available in the market that satisfy this benchmark process of analysis for setting the DRP under the NER. The AER considers that this sample of bonds is the best possible in the current circumstances, where there are no BBB+ bonds with a maturity close to ten years, but that if circumstances change then the sample of bonds should also be changed.

The observed yields were compared to the Bloomberg BBB fair value curve, the CBASpectrum BBB+ fair value curve and a simple average of the two curves using the weighted sum of squared errors. This comparison provided the results shown in table 11.7 and table 11.8.

Table 11.7: Fair value and observed yield analysis using weighted sum of squared errors over 15 days to 13 October 2009

		Observed yield source		
		Bloomberg	CBASpectrum	UBS
Fair Value Source	Bloomberg	0.6	1.5	0.7
	CBASpectrum	0.4	1.3	0.4
	Simple average of Bloomberg and CBASpectrum	0.5	1.4	0.5

Source: Bloomberg, CBASpectrum, UBS rate sheets and AER analysis.

Table11.8: Fair value and observed yield analysis using weighted sum of squared errors over 40 days to 13 October 2009

		Observed yield source		
		Bloomberg	CBASpectrum	UBS
Fair Value Source	Bloomberg	0.9	2.0	0.9
	CBASpectrum	0.5	1.4	0.5
	Simple average of Bloomberg and CBASpectrum	0.6	1.6	0.6

Source: Bloomberg, CBASpectrum, UBS rate sheets and AER analysis.

The AER considers that over both the 40 day and the 15 day period to 13 October 2009, CBASpectrum's BBB+ fair value curve has performed best at matching observed yields for the sample of bonds considered when performance is measured using the weighted sum of squared errors. This is true whether the source of the observed bond yields was Bloomberg, CBASpectrum or UBS.

The AER notes that this result should not be interpreted as endorsing or criticising the methodologies used by CBASpectrum and Bloomberg to develop their fair value curves. The AER also highlights that its approach to testing the reliability of Bloomberg and CBASpectrum has been and continues to be refined in light of the arguments presented during consultation and changing market circumstances. In recognising the imperfections in this approach and the reliance on methods which are not fully transparent, the potential for an alternative, custom-built estimation approach is being considered by the AER, ACCC and other regulators and may be developed for consultation in the near future.

AER conclusion

The credit rating level of BBB+ proposed by the Qld DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

Regarding the measurement of the DRP for clause 6.5.2(e) of the NER, the AER considers that the use of CBASpectrum's BBB+ fair value curve provides the best available prediction of observed yields for the purposes of determining the yield on the benchmark BBB+ 10 year corporate bond. This is based on a comparative analysis of the fair yield estimates of both data service providers against market data relevant to the benchmark corporate bond.

For this draft decision, the AER determines a DRP of 4.24 per cent.

11.5.6 Expected inflation

The expected inflation rate is not an explicit parameter within the WACC calculation. However, it is used in the PTRM to forecast nominal allowed revenues and to index the RAB.

The AER has previously specified a method to estimate of inflation over a 10-year period is to apply the RBA's short-term inflation forecasts—currently extending out to two years—and adopt the mid-point of its target inflation band beyond that period (2.5 per cent) for the remaining eight years.[814] An implied 10-year forecast is derived by a geometric average of these individual forecasts.[815]

The RBA's statement on monetary policy examines a wide variety of objective data influencing inflation in both the domestic and international financial markets to develop its inflation forecast. The forecast is produced on a regular basis and is publicly available, including supporting analysis and reasoning. This provides consistency and transparency in the AER method for deriving an inflation forecast.

Regulatory requirements

Clause 6.4.2(b)(1) of the NER states that the PTRM must specify:

> … a method that the AER determines is likely to result in the best estimates of expected inflation.

Qld DNSP regulatory proposals

The Qld DNSPs have used the AER's general approach for forecast inflation but using a simple average rather than a geometric average.

Issues and AER's considerations

In estimating forecast inflation, the AER is guided by the NER requirement that the appropriate approach to forecasting inflation should be a methodology that the AER determines is likely to result in the best estimate of expected inflation.[816] Historically, the AER has used an objective market-based (Fisher equation) approach to forecast the expected inflation rate—calculated as the difference between the CGS (nominal) and the indexed linked CGS yields. However, since late 2006, the limited supply of index linked CGS has resulted in trades in the market being decreased, which has increased the likelihood that the market for these securities is a poorly functioning market. Therefore, any analysis which uses the Fisher equation technique to derive the break even inflation forecast is likely to be unreliable at this point in time.

There have still not been any new issues of indexed linked CGS by the Australian government since the NSW and ACT distribution determinations in April 2009. The Australian Office of Financial Management (AOFM) has, however, announced it will be issuing index linked CGS around late September/early October 2009.[817] This has been confirmed with announcement that an indexed-linked treasury bond has been issued by the AOFM on 8 October 2009.[818] The AER considers that, while the yields

814 AER, *Final decision, ACT DNSP*, April 2009, p. 107; and AER, *Final decision, NSW DNSPs*, April 2009, p. 236.

815 A geometric average is used to account for compounding inflation between years. It is calculated by taking the n^{th} root of the product of the n numbers in the data set.

816 NER, clause 6.4.2(b)(1).

817 AOFM, Treasury indexed bonds – resumption of issuance and participation in syndicate, Operational notice, <http://www.aofm.gov.au/content/notices/15_2009.asp>, Accessed on: 27 August 2009.

818 AOFM, Pricing of new 2025 treasury indexed bond, Operational notice, < http://www.aofm.gov.au/content/notices/23_2009.asp>, Accessed on: 6 October 2009.

from indexed CGS are likely to be unreliable for the purposes of this draft decision due to the limited supply of these securities, it will re-examine this issue for the final decision.

In the absence of a credible market–based inflation forecasting methodology, the AER considers that the methodology adopted in the ACT and NSW distribution determinations remains appropriate for the purpose of determining the best estimate of expected inflation. That is, adopting an average inflation forecast based on the RBA's short–term inflation forecasts and the mid–point of its target inflation band.

The AER observes that the Qld DNSPs have used a simple average rather than a geometric average to estimate forecast inflation. Neither DNSP has justified this approach in their regulatory proposals. The AER considers that a geometric average is more appropriate than a simple average since it is consistent with the calculations in the PTRM, namely that forecast inflation has a compounding effect on revenues and prices. Therefore, the AER considers that the Qld DNSPs' inflation forecasting methodology should reflect this approach.

The AER also considers it is likely the approach taken to forecast inflation is likely to be an oversight rather than a deliberate departure from the approach outlined by the AER in its previous decisions. However, if the Energex and Ergon Energy have deliberately departed from the AER's preferred approach at this point in time, the AER requires supporting information to justify this position. The AER observes that there has been no supporting information in their regulatory proposals to justify such a departure.

The AER also considers that the estimate of expected inflation should be updated to incorporate the latest available data closer to the time of the final determination. Inflation forecasts can change in line with market sensitive data and regulatory practice in Australia has been to update these forecast values at the time of making a decision.

For this draft 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.[819] Based on this approach and using the latest RBA forecasts as shown in table 11.9, an inflation forecast of 2.45 per cent produces the best estimate for a 10 year period.[820]

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819 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, 6 December 2007; available at http://www.rba.gov.au/MonetaryPolicy/statement_conduct_mp_4_06122007.html [accessed 26 June 2009].

820 The AER notes that this will be updated to incorporate the latest available data at the time of the final decision.

Table 11.9: AER's conclusion on inflation forecast (per cent)

	June 2011	June 2012	June 2013	June 2014	June 2015	June 2016	June 2017	June 2018	June 2019	June 2020	Geometric average
Forecast inflation	2.00	2.50[a]	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.45

Source: RBA, *Statement on monetary policy*, 7 August 09, p. 75.

(a) The RBA has not yet released a forecast for the year ending June 2012. This forecast will be available and adopted by the AER (including any update forecasts) at the time of the final decision. The mid-point of its target inflation band has been assumed for the purposes of this draft decision.

AER conclusion

The Qld DNSPs' proposed method of estimating inflation is consistent with that recently adopted by the AER in its NSW electricity distribution determinations, with the exception of the use of a simple average. The AER considers that the use of a geometric average would likely result in a best estimate of expecting inflation, given that forecast inflation has a compounding affect in the PTRM. Therefore, the AER considers that Energex and Ergon Energy's inflation forecasting methodology should reflect this approach.

The AER considers, at this point in time, the yields from indexed CGS are likely to be unreliable due to the limited supply of these securities. However, given the AOFM's announcement, the AER will re-examine the liquidity of the index linked CGS market for the final decision.

The AER recognises that inflation forecasts will change in line with market sensitive data. Regulatory practice in Australia has been to update these forecast values at a time closer to the making of the final determination to take account of most recent information.

11.6 AER conclusion

The SORI defines a number of the WACC parameter values to be adopted by the Qld DNSPs for the purposes of setting a rate of return unless there has been a material change in circumstances. For the parameters where the values are calculated based upon a method—nominal risk–free rate and the debt risk premium—the SORI sets out the method to be used by the AER for determining the values.

For this draft decision, the AER has calculated an indicative nominal vanilla WACC of 10.06 per cent for the Qld DNSPs. The indicative WACC provided for in the draft decision is higher than that proposed by the Qld DNSPs because the risk–free rate and the DRP have increased since the Qld DNSPs prepared their regulatory proposals. The WACC determined by the AER does not include a proposed convenience yield.

Table 11.10 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk–free rate and DRP, based on the agreed averaging period, and the expected inflation rate at a time closer to the final Qld DNSPs' distribution determinations.

Table 11.10: AER conclusion on WACC parameters

Parameter	Energex	Ergon Energy
Nominal risk–free rate	5.44%	5.44%
Real risk–free rate	2.92%	2.92%
Expected inflation rate	2.45%	2.45%
Gearing level (Debt/Equity)	60:40	60:40
Market risk premium	6.5%	6.5%
Equity beta	0.80	0.80
Debt risk premium	4.24%	4.24%
Nominal pre–tax return on debt	9.68%	9.68%
Nominal post–tax return on equity	10.64%	10.64%
Nominal vanilla WACC	10.06%	10.06%

11.7 AER draft decision

In accordance with clause 6.12.1(5) of the NER, the rate of return to apply to Energex is 10.06 per cent.

In accordance with clause 6.12.1(5) of the NER, the rate of return to apply to Ergon Energy is 10.06 per cent.

12 Service target performance incentive scheme

12.1 Introduction

This chapter discusses the AER's application of the service target performance incentive scheme (STPIS) to the Qld DNSPs in the next regulatory control period.[821]

The STPIS establishes targets based on historical levels of performance, and provides incentives to DNSPs in the form of financial rewards for meeting targets and financial penalties for a failure to meet targets. The STPIS provides incentives for DNSPs to maintain and improve service performance. The regulatory framework provides DNSPs with an incentive to reduce costs where practical. In a situation where service performance is maintained or improved, cost reductions are beneficial to both DNSPs and their customers. However, cost efficiencies achieved at the expense of service levels experienced by customers are not desirable.

The STPIS has two broad components, the s–factor and the Guaranteed Service Levels (GSL) scheme. The s–factor is comprised of three components, namely reliability of supply, quality of supply and customer service.

12.2 Regulatory requirements

Clause 6.6.2(a) of the NER requires that the AER must publish an incentive scheme to provide incentives for DNSPs to maintain and improve performance.

Under clause 6.6.2(b) of the NER the AER must consult with authorities responsible for the administration of jurisdictional legislation. The AER is also required to ensure that service standards and targets do not put at risk the DNSP's ability to comply with jurisdictional service standards and targets.

Under clause 6.6.2(b)(3) of the NER, in developing and implementing a 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
>
> (ii) any regulatory obligation or requirement to which the DNSP is subject; and
>
> (iii) the past performance of the distribution network; and

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[821] 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 addressed amongst other things how the Major Event Day (MED) boundary is calculated. See AER, *Final decision, Electricity distribution network service providers, Service target performance incentive scheme*, November 2009, appendix C.

(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 schemes that apply to the DNSP under jurisdictional electricity legislation.[822]

The AER is required to publish a framework and approach paper prior to every distribution determination which amongst other things requires the AER to set out its likely approach to the application of the STPIS. Subject to clause 6.12.3 of the NER however, the AER's framework and approach paper is not binding on the AER or the DNSP.

Under clause 2.1(d) of the STPIS the AER is required to determine the following in accordance with the implementation of this scheme:

(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 MED 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

[822] NER, clause 6.6.2(b), note.

(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.

Transitional arrangements

Clause 11.16.5 of the NER states:

> In formulating a service target performance incentive scheme to apply to Energex and Ergon Energy for the regulatory control period, the AER, in addition to the requirements in clause 6.6.2(b), must also:
>
> (1) take into account the continuing obligations on Energex and Ergon Energy throughout the regulatory control period to implement the recommendations from the EDSD Review adopted by the Queensland Government;
>
> (2) take into account the impact of severe weather events on service performance; and
>
> (3) consider whether the scheme should be applied by way of a paper trial or whether a lower powered incentive is appropriate.

12.3 AER framework and approach

The AER published its framework and approach paper for the Qld DNSPs in November 2008. In its framework and approach paper, the AER stated that it would apply its STPIS to the Qld DNSPs for the next regulatory control period. The AER stated that its STPIS would operate in conjunction with the Minimum Service Standards (MSS) and GSL schemes that apply to the Qld DNSPs under the Electricity Industry Code.[823]

The AER also stated that it would apply the reliability of supply and customer service components of the STPIS to the Qld DNSPs in the next regulatory control period as set out in table 12.1 and table 12.2.

[823] AER, *Final framework and approach paper: Application of schemes – Energex and Ergon Energy 2010–15,* November 2008, pp. 24–26.

Table 12.1: Energex – applicable parameters for the STPIS

Component	Network segment
Reliability of supply	
SAIDI	CBD feeders
	Urban feeders
	Short rural feeders
SAIFI	CBD feeders
	Urban feeders
	Short rural feeders
Customer service	
Telephone answering	All of network

Source: AER, *Final framework and approach paper: Application of schemes*, November 2008, p. 76.

Table 12.2: Ergon Energy – applicable parameters for the STPIS

Component	Network segment
Reliability of supply	
SAIDI	Urban feeders
	Short rural feeders
	Long rural feeders
SAIFI	Urban feeders
	Short rural feeders
	Long rural feeders
Customer service	
Telephone answering	All of network

Source: AER, *Final framework and approach paper: Application of schemes*, November 2008, p. 76.

Under the reliability of supply component, the AER's position in the framework and approach paper was that the unplanned system average interruption frequency index (SAIFI) and unplanned system average interruption duration index (SAIDI) parameters would apply to Energex and Ergon Energy. The STPIS performance targets would be established at or above the current MSS levels established by the QCA. The momentary average interruption frequency index (MAIFI) parameter would not be applied to the Qld DNSPs as they do not currently have the capacity to measure momentary interruptions.

In relation to the customer service component, the AER's position in the framework and approach paper was to apply the telephone answering parameter in the next regulatory control period to the Qld DNSPs.

The STPIS does not include any quality of supply parameters. The AER stated in its framework and approach paper that the Qld DNSPs will be required to measure and report quality of supply data in the next regulatory control period.

Consistent with the STPIS, the AER's position set out in the framework and approach paper was that the GSL component of the scheme would not apply to the Qld DNSPs in the next regulatory control period as the Qld DNSPs are currently subject to a jurisdictional GSL scheme.[824]

12.4 Qld DNSP regulatory proposals

Although the STPIS is mandatory, its application may be varied by the AER. DNSPs may also propose to vary the application of the scheme, although only to the extent that such variation is allowed for by the STPIS, and provided that it demonstrates that such variation is consistent with clause 6.6.2(b)(3) of the NER.

Energex

Energex proposed that the AER vary the application of the STPIS set out in the framework and approach paper as follows:

- For the first year of the next regulatory control period, Energex proposed that the STPIS should take the form of a paper trial, that is, no financial reward or penalty should apply. Energex proposed a revenue at risk of ±1 per cent in the second year of the next regulatory control period. Energex proposed that the scheme would only be fully implemented, that is ±2 per cent revenue at risk, from the third year of the next regulatory control period onwards until the end of the next regulatory control period.[825]

- Energex proposed that for the first two years of the next regulatory control period, the STPIS should exclude the telephone answering parameter because there was insufficient data. Under its proposal the telephone answering parameter would only be included in the STPIS for the final three years of the next regulatory control period.[826]

- Energex proposed that the AER apply a telephone answering parameter based on a measure of the Average Speed of Answer (ASA) rather than Grade of Service (GOS) as set out in the STPIS.[827]

- Energex proposed to adopt value of customer reliability (VCR) values based on the AER's original STPIS Guideline (version 01.0) with the same value for each of the reliability network segments.[828]

Ergon Energy

Ergon Energy did not propose any variations to the application of the STPIS to that set out in the framework and approach paper.[829]

824 AER, *Final framework and approach paper: Application of schemes*, November 2008, pp. 24–26.
825 Energex, *Regulatory proposal*, July 2009, pp. 256–258.
826 Energex, *Regulatory proposal*, July 2009, pp. 258–259.
827 Energex, *Regulatory proposal*, July 2009, p. 256.
828 Energex, *Regulatory proposal*, July 2009, pp. 259–260.
829 Ergon Energy, *Regulatory proposal*, July 2009, p. 398.

12.5 Submissions

The Energy Users Association of Australia (EUAA) commented that it considered the STPIS a 'welcome development'. It also submitted that quality of supply is an important factor for its customers and was concerned that the STPIS focuses on only a few measures and submitted that the AER consider extending the STPIS into other areas.[830]

12.6 Consultant review

The AER engaged PB to review any changes to the STPIS that the Qld DNSPs proposed, and how these changes would be implemented. PB was required to review historical performance, as well as the impact that the forecast capex and opex programs had on performance. Specifically, PB:[831]

- examined any reliability improvements completed or planned to be completed within the current regulatory control period and any other factors that may affect reliability performance
- advised whether the defined exclusions to the scheme were appropriately removed from the performance data on which targets were based
- assessed the appropriateness of proposed targets, incentive rates and other values proposed for each parameter
- advised whether the overall revenue at risk, and the revenue at risk for each customer service parameter, was limited as required by the scheme.

PB made recommendations on appropriate reliability of supply and customer service performance targets to be applied to the Qld DNSPs in the next regulatory control period.

Energex

In relation to Energex's reliability of supply parameters PB recommended that:[832]

- a paper trial and incremental approach to revenue at risk was not justified by Energex
- the proposed variation to the VCR was not consistent with the objectives of clause 1.5 of the STPIS and that the VCR values set out in clause 3.2.2(b) of version 01.1 of the STPIS should apply to Energex
- the SAIDI and SAIFI 2007–08 baseline performance and performance targets for the next regulatory control period were reasonable

[830] EUAA, *Submission to the AER*, 28 August 2009, section 4.1.
[831] PB, *Report – Energex*, October 2009; and PB, *Report – Ergon Energy*, October 2009, p. 7.
[832] PB, *Report – Energex*, October 2009, p. 139.

- a revenue at risk cap of ±2 per cent should apply for the entire duration of the next regulatory control period.

In relation to Energex's customer service parameter PB recommended that:[833]

- the proposed variation to the telephone answering parameter based on a measure of the ASA is not appropriate to include in the STPIS
- the structural break in call centre data is significant such that historical data before the change to the business structure would not reflect future performance. No targets should apply for 2010–11. Targets for 2011–12 to 2014–15 should be set at the average performance of the three years of data from 2008–09 to 2010–11
- a revenue at risk cap of ±0.2 per cent should apply for the telephone answering parameter.

Ergon Energy

In relation to Ergon Energy's reliability of supply parameter PB considered that the targets for SAIDI and SAIFI should be set at Ergon Energy's internal business targets to reflect the likely future performance after taking account of the proposed capex and opex likely to impact on future service levels.

PB's recommendations in relation to Ergon Energy's customer service parameter were as follows:[834]

- the target for the telephone answering parameter should be set at 77.3 per cent for each year of the next regulatory control period
- the maximum revenue increment or decrement for the telephone answering parameter be set at 0.2 per cent.

12.7 Issues and AER consideration

12.7.1 Relationship between forecast expenditure and the STPIS

The AER notes that there is a relationship between the capex and opex allowances provided to fund (amongst other things) reliability of supply and the STPIS. The STPIS provides financial incentives for the DNSPs to improve reliability of supply service performance. Clause 3.2.1(a)(1A) of the STPIS requires the AER to consider historical and forecast expenditure in setting targets for the STPIS to ensure that DNSPs do not receive a benefit under the STPIS for improving service where this improvement has been funded through the capex or opex allowances.

For the purpose of forecasting expenditures both Qld DNSPs proposed to improve the level of reliability of supply service performance to meet the MSS targets set out in the Electricity Industry Code.

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[833] PB, *Report – Energex*, October 2009, p. 139.
[834] PB, *Report – Ergon Energy*, October 2009, p. 159.

PB considered that Energex's proposed expenditure to meet these levels of performance was appropriate.[835] Energex did not propose any other expenditure to fund changes or improvements in service performance. PB noted that performance targets over the next regulatory control period have been set by Energex to match improvements expected from reliability improvement projects proposed in the forecast expenditures.[836]

The AER notes that in recommending performance targets for Energex, PB has taken into account increased expenditure to improve reliability. The AER is therefore satisfied that Energex will not receive any benefit under the STPIS for improving service performance where this performance has otherwise been funded through either the capex or the opex allowances.

In relation to Ergon Energy, PB considered Ergon Energy's proposed expenditure would result in improvements to reliability performance. PB considered that not all of this expenditure was efficient and recommended reductions (see chapter 7 of this draft decision).[837] After the reduction to expenditure PB considered that Ergon Energy would still meet the internal targets on which forecasts of expenditure were based.

PB recommended amendments to the performance targets proposed by Ergon Energy for the STPIS. PB noted that forecast expenditure was based on internal targets rather than the MSS (Ergon Energy's internal targets require better service performance than the MSS). Therefore, performance targets for the STPIS have been set at the internal targets rather than the MSS as proposed by Ergon Energy.

After amending SAIDI and SAIFI targets and amending forecast expenditure, the AER is satisfied that Ergon Energy will not receive any benefit under the STPIS for improving service performance where this performance has otherwise been funded through either the capex or the opex allowances.

12.7.2 Applicable components and parameters

The AER stated in its framework and approach paper that under the reliability of supply component, targets would be set for both SAIDI and SAIFI, with financial incentives attached to each. The AER stated that Energex's network would be segmented according to network type (CBD, urban and short rural feeder categories).[838] The AER stated that Ergon Energy's network would also be segmented according to network type (urban, short rural and long rural feeder categories).[839]

The AER's framework and approach paper also stated that the telephone answering customer service parameter (as defined in appendix A of the STPIS) would apply to the Qld DNSPs in the next regulatory control period.[840]

835 PB, *Report – Energex*, October 2009, p. 127.
836 PB, *Report – Energex*, October 2009, p. 133.
837 PB, *Report – Ergon Energy*, October 2009, p. 157.
838 AER, *Final framework and approach paper: Application of schemes*, November 2008, pp. 24–25.
839 AER, *Final framework and approach paper: Application of schemes*, November 2008, pp. 25–26.
840 AER, *Final framework and approach paper: Application of schemes*, November 2008, pp. 24–26.

The AER also stated it would not apply the GSL component of the STPIS in the next regulatory control period as the Qld DNSPs will be subject to a jurisdictional GSL scheme administered by the QCA.[841]

Regulatory proposals

Energex stated that the historical trends associated with the previous retail and network contact centre are not representative of performance for the smaller network contact centre only. It considered that any STPIS targets based on historical performance data prior to 2008–09 would pose an unreasonable financial risk on it. Energex stated it has less than one financial year of telephone answering data for its network only contact centre and considered it had an insufficient basis on which to forecast STPIS targets for telephone answering for the network contact centre.[842]

Energex therefore proposed that for the first two years of the next regulatory control period, the STPIS should exclude the telephone answering parameter, that is a paper trial should apply for years 2010–11 to 2011–12. Under this proposal the telephone answering parameter would only be included in the STPIS for the final three years of the next regulatory control period. It proposed that targets for 2012–13, 2013–14 and 2014–15 would be derived from the three years of data from 2008–09 to 2010–11.[843]

Energex did not propose any adjustments to the reliability of supply components and parameters.

Ergon Energy did not propose any adjustments to the applicable components and parameters to that set out in the framework and approach paper.[844]

Submissions

The EUAA stated that quality of supply is an important factor for its customers. The EUAA also noted a concern that the STPIS focuses on only a few measures and requested the AER to consider extending the STPIS into other areas.[845]

Consultant review

PB agreed with Energex that there was a lack of available data on which to set targets and therefore considered that the telephone answering parameter should not apply in years 2010–11 and 2011–12.[846]

PB advised in relation to Ergon Energy that it found no issues that might affect the use of the telephone answering data in the STPIS.[847]

AER considerations

In relation to the EUAA's submission regarding quality of supply and the possibility of extending the STPIS into other areas, the AER considered the quality of supply

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841 AER, *Final framework and approach paper: Application of schemes*, November 2008, pp. 24–25.
842 Energex, *Regulatory proposal*, July 2009, p. 258.
843 Energex, *Regulatory proposal*, July 2009, p. 259.
844 Ergon Energy, *Regulatory proposal*, July 2009, p. 399.
845 EUAA, *Submission to the AER*, 28 August 2009, section 4.1
846 PB, *Report – Energex*, October 2009, p. 138.
847 PB, *Report – Ergon Energy*, October 2009, p. 158.

component in developing its framework and approach for the Qld DNSPs.[848] The AER stated it will continue to require the Qld DNSPs to collect and report on quality of supply parameters in the next regulatory control period. There is currently no quality of supply component included in the STPIS. At this stage no targets will be assigned to these parameters and no revenue will be placed at risk. The AER considers that there is value in the Qld DNSPs continuing to collect and report on this data to enable application of quality of supply parameters should the STPIS be amended in the future to include quality of supply.

Based on the advice of PB, the AER agrees with Energex that there is insufficient data on which to set targets for the telephone answering parameter at the start of the next regulatory control period.

The AER notes that the data for setting targets for the telephone answering parameters for years 3 to 5 of the next regulatory control period is also not currently available.[849] As this data is yet to become available the AER is unable to assess the data prior to implementing this parameter of the scheme. The AER is wary of implementing a component of the STPIS on the basis of data which it has not seen or had the opportunity to review. Therefore, the AER does not consider it appropriate to apply the telephone answering parameter of the STPIS to Energex in the next regulatory control period.

The AER will apply the SAIDI and SAIFI reliability of supply parameters but not the telephone answering customer service parameter to Energex. The components and parameters of the STPIS applicable to Energex are set out in table 12.3.

Table 12.3: Energex – applicable parameters for the STPIS

Component	Network segment
Reliability of supply	
SAIDI	CBD feeders
	Urban feeders
	Short rural feeders
SAIFI	CBD feeders
	Urban feeders
	Short rural feeders

The AER notes that Ergon Energy did not propose any variation to the applicable components and parameters of the STPIS as set out in the AER's framework and approach paper. Based on the advice of PB, the AER is satisfied that there is sufficient data available for the purpose of setting targets for the telephone answering component of the STPIS for Ergon Energy.

848 AER, *Preliminary positions for the framework and approach paper: Application of schemes Energex and Ergon Energy 2010–15*, June 2008 p. 17.

849 The AER notes that some data will become available during the next regulatory control period.

The AER will therefore apply the SAIDI and SAIFI reliability of supply parameters and the telephone answering customer service parameter to Ergon Energy. The components and parameters of the STPIS applicable to Ergon Energy are set out in table 12.2.

12.7.3 Revenue at risk

Framework and approach

In its framework and approach paper, the AER stated it would apply the STPIS to the Qld DNSPs with a lower powered incentive of ±2 per cent of revenue at risk.[850]

Regulatory proposals

Energex proposed to adopt the overall revenue at risk of ±2 per cent subject to a staged introduction. Energex proposed to:[851]

- apply a paper trial with no revenue at risk in year 1 (2010–11)
- apply ±1 per cent revenue at risk in year 2 (2011–12)
- apply ±2 per cent revenue at risk in years 3 to 5 (2012–13 to 2014–15).

In support of a staged introduction approach, Energex submitted that:

- This approach would allow it to understand and prepare for the financial and operational implications of the scheme prior to application of significant financial penalties or rewards. Energex submitted this approach would also protect the interests of customers.[852]
- Under the MSS, Energex is accountable to the Queensland Government for improving reliability performance. Energex stated that there may be conflicting signals between the MSS which will require Energex to improve the performance of rural feeders (as they are currently underperforming the MSS targets) and the STPIS which provides incentives to improve performance of urban feeders. Energex stated that its MSS obligations must be considered by the AER in introducing the STPIS.[853]
- Its overall reliability performance has improved significantly and therefore submitted that the STPIS is not symmetrical given there is limited opportunity for further improvement.[854]
- It engaged KPMG to undertake a study to understand consumer preferences for electricity distribution service standards.[855] Energex noted the findings of the

[850] AER, *Final framework and approach paper: Application of schemes*, November 2008, pp. 24–25.
[851] Energex, *Regulatory proposal*, July 2009, p. 258.
[852] Energex, *Regulatory proposal*, July 2009, p. 257.
[853] Energex, *Regulatory proposal*, July 2009, p. 257.
[854] Energex, *Regulatory proposal*, July 2009, p. 257.
[855] Energex, *Regulatory proposal*, July 2009, appendix 17.3.

report, in particular, only 25 per cent indicated a willingness to pay 'a little more' for a more reliable electricity supply.[856]

Ergon Energy did not propose any amendment to the cap on revenue at risk of ±2 per cent contained in the AER's framework and approach paper.[857]

Consultant review

PB noted the AER's position in its framework and approach paper that 'the DNSP's inexperience in implementing a scheme that places revenue at risk is not by itself a sufficient reason to apply the STPIS by way of a paper trial'.[858]

PB considered Energex's argument relating to the interplay between the MSS and the STPIS and whether it justified deferring the application of the revenue at risk in the first two years. PB noted that the higher focus for improvement on the rural feeders under MSS against the higher reward or penalty associated with urban feeders under the STPIS is not restricted to the first and second regulatory years of the next regulatory control period. PB therefore concluded that Energex's argument relating to the interplay between MSS and STPIS should not prevent the application of a revenue at risk reward or penalty in the first two years.[859]

PB considered that, based on the KPMG Report, Energex's customers expressed a demand for improved reliability of supply. Further, PB considered that in regard to improved service, the majority of Energex's customers are either willing to pay more or open to paying more.[860] PB noted that the majority of Energex's customers are either willing to pay more or are open to paying more. Therefore, PB considered that Energex did not clearly demonstrate that customers were not willing to pay more.[861]

AER considerations

A DNSP's inexperience in implementing a scheme that places revenue at risk is not a reason to apply the STPIS by way of a paper trial. The AER considers that the benefits to the customers of financial incentives attached to the STPIS from the start of the next regulatory control period outweigh any potential detriment and therefore warrant the potential rewards or penalties that a DNSP may incur under the scheme.

The AER notes that clause 6.6.2(b)(3)(v) of the NER requires the AER to take account of the need to ensure that the incentives under the STPIS are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels.

Implementing the STPIS by way of a paper trial means that, while relevant data is collected and ensuing rewards and penalties are calculated, no revenue is placed at risk. Applying the STPIS without revenue at risk will not offset any financial incentive the Qld DNSPs have to reduce costs at the expense of service levels. To

856 Energex, *Regulatory proposal*, July 2009, p. 257.
857 Ergon Energy, *Regulatory proposal*, July 2009, p. 402.
858 PB, *Report – Energex*, October 2009, p. 134.
859 PB, *Report – Energex*, October 2009, p. 134.
860 PB, *Report – Energex*, October 2009, p. 129.
861 PB, *Report – Energex*, October 2009, p. 134.

ensure the effective operation of the STPIS the AER considers it important that a financial incentive be applied during the next regulatory control period.

The AER notes PB's advice that a conflict between the focus of the MSS and the STPIS does not support the deferral of the STPIS for the first two years. Regarding the broader issue of the potential conflicting signals to Energex's operational staff because of the difference in focus, the AER notes that the STPIS is designed to operate concurrently with jurisdictional MSS schemes and is not intended to affect the MSS focus. The performance targets under the STPIS have been set higher than the MSS and therefore unless the AER's performance targets are met achieving the MSS will not result in a reward. The AER notes that the MSS does not have a financial incentive attached to it and to the extent that Energex decides to focus only on the STPIS it will still be subject to any jurisdictional sanctions. Accordingly, the AER does not consider that the obligations under the MSS and to the Queensland Government prevent the AER from attaching financial incentives to the STPIS for the first two years of the next regulatory control period.

The AER accepts that Energex's overall reliability performance has improved. The AER notes that the purpose of the STPIS is to maintain and improve service performance.[862] PB considered that performance targets over the next regulatory control period have been set to match improvements expected from reliability improvement projects proposed in the forecast expenditures program.[863] The AER considers that on average, any efficiency gains will allow Energex to outperform its targets. As the AER has approved forecast expenditure that will allow it to keep service performance in line with performance targets, the AER does not accept Energex's argument that the risks of the STPIS are not symmetrical.

PB advised that KPMG's study suggests that the majority of Energex's customers are either willing to pay more or could be persuaded to paying more. Therefore, the AER accepts PB's conclusions that this report does not clearly demonstrate that customers were not willing to pay more.

The AER does not consider that this approach will adversely impact the incentives the Qld DNSPs have to implement non-network alternatives.

Overall, the AER considers that Energex's proposal to apply a staged approach to the revenue at risk starting out with a paper trial fails to satisfy the criteria set out at clause 6.6.2(b)(3) of the NER. The AER does not consider it appropriate in this instance to depart from the approach set out in the framework and approach paper and accordingly will apply a cap on revenue at risk of ±2 per cent to both Qld DNSPs in the next regulatory control period.

The AER considers it appropriate to maintain the value of the customer service parameter in the scheme at about 10 per cent of the total incentive. As the cap on overall revenue at risk is ±2 per cent for the Qld DNSPs, the AER proposes to apply a cap to the revenue at risk of ±0.2 per cent for the telephone answering customer service parameter to Ergon Energy.

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[862] Clause 6.6.2(a) of the NER.

[863] PB, *Report – Energex*, October 2009, p. 133.

12.7.4 Incentive rates

Framework and approach

The AER stated that the willingness of customers to pay for improved levels of service is reflected in the VCR that applies to the reliability of supply and telephone answering parameters.

The VCR values contained in the STPIS are based on the findings of a Charles River Associates (CRA) study. The incentive rate for the telephone answering parameter is based on the results of the 2002 survey undertaken in South Australia by KPMG and subsequent analysis by Essential Services Commission of Victoria (ESCV). When developing its STPIS the AER considered that these were the most recent documented and robust work on reliability incentive rates.[864]

Regulatory proposals

Energex proposed to apply the VCRs which were included in the STPIS in version 01.0 rather than the higher VCRs which were included in the STPIS in version 01.1 (the VCR values were updated in version 01.1 to reflect the most recent CRA Report).[865]

To support its proposal to apply alternative VCRs, Energex engaged KPMG to undertake a study to understand consumer preferences for electricity distribution service standards.[866] Energex noted the findings of the report, in particular, only 25 per cent indicated a willingness to pay 'a little more' for a more reliable electricity supply while approximately 47 per cent of respondents were not willing to pay more and 28 per cent were open to persuasion.[867] Energex indicated a concern with increasing energy prices and submitted that a lower incentive rate would keep energy prices down.[868]

Ergon Energy did not propose any variation to the VCR or incentive rates set out in the framework and approach paper.[869]

Consultant review

PB considered that the KPMG Report implies that the majority of Energex's customers are willing to pay more for improved performance or are open to paying more.[870]

PB stated that Energex had not carried out quantitative studies to determine an alternative VCR. Energex instead proposed to apply the VCRs included in STPIS

[864] AER, *Final framework and approach paper: Application of schemes*, November 2008, p. 23.
[865] Energex, *Regulatory proposal*, July 2009, p. 259.
[866] Energex, *Regulatory proposal*, July 2009, appendix 17.3, confidential.
[867] Energex, *Regulatory proposal*, July 2009, p. 259.
[868] Energex, *Regulatory proposal*, July 2009, pp. 259–260.
[869] Ergon Energy, *Regulatory proposal*, July 2009, p. 402.
[870] PB, *Report – Energex*, October 2009, p. 129.

version 01.0. Energex did not explain why it chose to apply the VCR from STPIS version 01.0.[871]

PB considered that Energex asked for a lower incentive rate so that potential price increases are restrained. PB stated that the STPIS uses VCR to establish the efficient level of network investment in reliability.[872]

PB noted that the majority of Energex's customers are either willing to pay more or could be persuaded to paying more. Therefore, PB considered that Energex had not demonstrated that customers are not willing to pay more and therefore recommended that the AER apply the incentive rates set out in version 01.1 of the STPIS.[873]

AER considerations

The AER notes that under clause 3.2.2(d) of the STPIS a DNSP can propose an alternative VCR. However, an alternative VCR under section 2.2 of the STPIS requires that the DNSP provide the calculations or methodology for the alternative VCR. The AER considers that Energex has not carried out quantitative studies or provided calculations to determine an alternative VCR as required by section 2.2 of the STPIS.

PB advised that KPMG's study suggests that the majority of Energex's customers are either willing to pay more or are open to paying more. The AER accepts PB's conclusions that the KPMG report does not clearly demonstrate that customers were not willing to pay more. The AER considers that the Qld DNSPs have not demonstrated that their customers are willing to pay more.

Accordingly, the AER will calculate the incentive rates for the reliability of supply parameters to apply in the next regulatory control period in accordance with clause 3.2.2 and appendix B of version 01.2 of the STPIS. These parameters are set out at tables 12.4 and 12.5. An incentive rate of –0.040 per cent will apply to the Ergon Energy's telephone answering parameters, consistent with clause 5.3.2(a)(1) of the STPIS.

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871 PB, *Report – Energex*, October 2009, p. 130.
872 PB, *Report – Energex*, October 2009, pp. 129–130.
873 PB, *Report – Energex*, October 2009, p. 130.

Table 12.4: AER incentive rates for Energex 2010–15

Parameter	Incentive rate
Reliability of supply component	
SAIDI	
CBD	0.0086
Urban	0.0621
Short-rural	0.0132
SAIFI	
CBD	0.7824
Urban	4.1450
Short-rural	1.0725

Source: AER analysis; and Energex, *Regulatory proposal*, July 2009, p. 261.

Table 12.5: AER incentive rates for Ergon Energy 2010–15

Parameter	Incentive rate
Reliability of supply component	
SAIDI	
Urban	0.0214
Short-rural	0.0185
Long-rural	0.0042
SAIFI	
Urban	1.6933
Short-rural	1.9377
Long-rural	0.5649
Customer service component	
Telephone answering parameter	–0.0400

Source: AER analysis; and Ergon Energy, *Regulatory proposal*, July 2009, p. 404.

12.7.5 Transitional arrangements

Clause 11.16.5 of the NER sets out the transitional issues that the AER must have regard to in applying a STPIS to the Qld DNSPs.

Under clause 11.16.5(1) of the NER the AER is required to take into account the continuing obligations on the Qld DNSPs throughout the next regulatory control period to implement the recommendations from the EDSD Review adopted by the Queensland Government.

The central recommendation from the EDSD Review was that the Queensland Government mandate minimum service standards for the Qld DNSPs. The EDSD

Review also recommended that the QCA introduce a service quality incentive regime for the Qld DNSPs.[874] The AER considers the application of the STPIS will not prevent the Qld DNSPs from seeking to comply with the recommendations of the EDSD Review recommendations.

Under 11.16.5(2) of the NER the AER is required to take into account the impact of severe weather events on service performance. The STPIS takes into account the impact of severe weather events on service performance by excluding events under the major events day boundary. Clauses 3.2.1(a)(2) and 5.3.1(b)(2) of the STPIS provide that performance targets be modified by any other factors, such as severe weather events, that are expected to affect network reliability performance materially.

Clause 11.16.5(3) of the NER requires the AER to consider whether the STPIS should be applied by way of a paper trial or whether a lower powered incentive is appropriate. The AER considered, as discussed in section 12.7.2 of this draft decision, that it is not appropriate to apply the STPIS to the Qld DNSPs by way of a paper trial. However, for the reasons set out in the framework and approach paper the AER considered it reasonable to apply the scheme by way of a lower powered incentive with ±2 per cent of revenue at risk.

12.7.6 GSL

The AER indicated in its framework and approach paper that it would not apply the GSL component of the STPIS to the Qld DNSPs as a GSL scheme administered by the QCA was in place.[875]

In implementing the STPIS the AER is required, under clause 6.6.2(b)(3)(ii) of the NER, to take account of any regulatory obligations or requirements to which a DNSP is subject. The AER notes that a GSL scheme administered by the QCA continues to operate.[876] Accordingly, the AER maintains the position in its framework and approach paper that it will not apply the GSL component of the STPIS to the Qld DNSPs in the next regulatory control period unless the Qld Government ceases to apply the GSL in Qld.

12.7.7 Alternative telephone answering parameter

Regulatory proposals

Energex proposed that the AER apply a telephone answering parameter based on a measure of the ASA rather than GOS measure which is contained in the STPIS.[877]

Ergon Energy did not propose any variation to the application of the telephone answering customer service parameter as set out in the AER's framework and approach paper.[878]

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[874] Queensland Department of Natural Resources, Mines and Energy, *Detailed report of the Independent Panel: Electricity Distribution and Service Delivery for the 21st Century*, Queensland, July 2004, p. 57.

[875] AER, *Final framework and approach paper: Application of schemes*, November 2008, p. 24.

[876] Queensland Department of Mines and Energy, *Electricity Industry Code (Queensland), fourth edition*, 31 July 2008, pp. 16–25 and 125.

[877] Energex, *Regulatory proposal*, July 2009, p. 256.

Consultant review

PB conducted a review of the ASA measure compared to the GOS measure and considered that:[879]

- the ASA measure excludes abandoned calls which PB stated occur during 'overload events'. PB stated that applying the ASA measure would not encourage Energex to maintain or improve this aspect of service performance

- the ASA measure is not more likely to meet customers' willingness to pay for service improvements than a GOS measure

- providing an incentive that ensures that all callers to the fault call line can be answered within a reasonable period of time (the GOS approach) is more consistent with the nature of the service provided by a fault call line than encouraging an improvement in the average speed to answer.

PB generally considered the GOS measure to be more consistent with the objectives of the STPIS and concluded that the ASA is not an appropriate parameter to include in the STPIS.[880]

AER considerations

The AER notes that any amendment to the telephone answering parameter for the STPIS should be consistent with the objectives of the STPIS. The AER notes PB's advice that the GOS measure is more consistent with the objectives of the STPIS than the ASA measure. However, as discussed in section 12.7.2, the AER does not propose to apply the telephone answering customer service parameter to Energex.

12.7.8 Performance targets

Framework and approach

In its framework and approach paper, the AER noted that both Qld DNSPs indicated that they intend to propose capex and opex in the next regulatory control period to achieve the MSS targets. The AER was concerned that if performance targets were set on the basis of average historical data it would be possible for the Qld DNSPs to be rewarded for achieving higher performance standards even though capex and opex allowances have been provided to fund this level of service.[881]

In its framework and approach paper the AER stated that SAIDI and SAIFI performance targets should be determined according to the following principles:[882]

- a DNSP's average historical performance should be modified to reflect the exclusions and definitions contained in the AER's STPIS

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[878] Ergon Energy, *Regulatory proposal*, July 2009, pp. 404–406.
[879] PB, *Report – Energex*, October 2009, pp. 134–137.
[880] PB, *Report – Energex*, October 2009, p. 137.
[881] AER, *Final framework and approach paper: Application of schemes*, November 2008, p 14.
[882] AER, *Final framework and approach paper: Application of schemes*, November 2008, p 13–14.

- a DNSP's average historical performance should be modified according to clause 3.2.1(a) of the scheme to account for completed or planned reliability improvements and any other factor expected to materially affect network reliability performance

- where a DNSP's modified average historical performance is below (that is, less onerous than) the MSS performance targets for that regulatory year, the performance target for that parameter will be set equal to the MSS target for that regulatory year

- where a DNSP's modified average historical performance is better (that is, more onerous) than the MSS performance target for that regulatory year, the performance target for that regulatory year will be set equal to the average historical performance.

Regulatory proposals

Energex engaged Evans & Peck to assist it to develop a methodology for setting targets.[883] Energex stated that under this methodology Evans & Peck:[884]

- conducted a historical analysis which considered the average performance over the previous five regulatory years and the impact of capex and opex programs in the previous regulatory control period

- set baseline performance (2007–08)

- proposed SAIDI and SAIFI targets which reflected the impact of capex and opex programs in the next regulatory control period.

Ergon Energy proposed that the STPIS targets be set at the lower of the annual MSS or the historical average performance. Ergon Energy stated that the MSS reflects the proposed works program in the next regulatory control period.[885]

Consultant review

Energex

PB confirmed that the reliability data did not include any of the events that meet the exclusion criteria set out in clause 3.3 of the STPIS.[886]

PB considered that historical improvement in SAIDI and SAIFI since 2003–04 accorded with funded reliability improvements over the period. PB analysed the forecast reliability improvements from forecast capex and opex and concluded that the expenditure correlated with Energex's proposed SAIDI and SAIFI targets.[887]

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883 Evans & Peck, *Energex service target performance incentive scheme assessment of targets, impacts and risks*, April 2009, confidential.
884 Energex, *Regulatory proposal*, July 2009, pp. 262–263.
885 Ergon Energy, *Regulatory proposal*, July 2009, p. 400.
886 PB, *Report – Energex*, October 2009, p. 130.
887 PB, *Report – Energex*, October 2009, p. 130.

PB considered that the baseline performance determined by Evans & Peck was reasonable and consistent with the STPIS as well as the principles set out in the framework and approach paper. Based on its analysis, PB considered that the targets have been set such that Energex will not receive any benefit under the STPIS for improving service performance where this service performance has otherwise been funded through either the capex or opex allowances.[888]

Ergon Energy

PB considered that Ergon Energy's internal targets reflect the likely service performance consistent with the proposed forecast expenditures.[889]

PB identified that part of Ergon Energy's proposed capex was attributable to reliability improvements and would likely improve aspects of performance. Although recommending a reduction to this proposed expenditure, PB still considered that the expenditure would result in improvements in reliability performance.

PB also noted that the MSS are minimum levels of service performance, whereas the targets under the STPIS are set at the average performance. PB stated that Ergon Energy set its internal targets 10 per cent better than the MSS targets. By setting its internal targets significantly better than the MSS targets, Ergon Energy was ensuring service performance of at least the minimum standard.[890] Further, by proposing that the performance targets be set in line with MSS targets, Ergon Energy was ensuring that it would outperform the STPIS targets.

PB concluded that it was appropriate to set reliability targets at Ergon Energy's internal business targets (which reflect its likely average) rather than the MSS targets as proposed by Ergon Energy. According to PB, this will ensure that where the forecast capex and opex allowances were funding performance improvements, Ergon Energy would not also receive a benefit under the STPIS for these improvements.[891]

PB recommended that Ergon Energy's target for the telephone answering parameter should be set at 77.3 per cent for each year of the next regulatory control period.[892]

AER considerations

In addition to the principles in the framework and approach paper, clause 3.2.1(a) of the STPIS states that performance targets must be established with reference to average historical performance. These targets should then be modified to account for completed or planned reliability improvements and any other factor expected to affect network reliability performance.

The STPIS does not set out an approach for how this modification should be undertaken. However, such a modification must take account of expenditure programs and should be supported by statistical analysis.[893]

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888 PB, *Report – Energex*, October 2009, p. 130.
889 PB, *Report – Ergon Energy*, October 2009, p. 157.
890 PB, *Report – Ergon Energy*, October 2009, pp. 156–157.
891 PB, *Report – Ergon Energy*, October 2009, p. 157.
892 PB, *Report – Ergon Energy*, October 2009, p. 158.
893 AER, *Final framework and approach paper: Application of schemes*, November 2008, p. 15.

Energex

The AER notes that PB was satisfied with the methodology adopted by Energex which was based on the Evans & Peck analysis. Further, the targets proposed are consistent with the STPIS as well as the principles set out in the framework and approach paper. The AER therefore accepted the performance targets proposed by Energex. The AER will apply the performance targets as set out at table 12.6.

Table 12.6: AER performance targets for Energex – 2010–11 to 2014–15

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
CBD	minutes	3.3	3.3	3.3	3.3	3.3
Urban	minutes	69.4	67.7	66.0	64.29	63.0
Short rural	minutes	173.2	164.4	158.0	152.4	147.6
SAIFI						
CBD	per 0.01 interruptions	0.032	0.032	0.032	0.032	0.032
Urban	per 0.01 interruptions	1.044	1.032	1.020	1.008	0.996
Short rural	per 0.01 interruptions	2.285	2.201	2.120	2.041	1.967

Ergon Energy

Ergon Energy stated that its proposed STPIS targets are based on the MSS as it reflects the proposed works program in the next regulatory control period.[894] PB noted that Ergon Energy's internal targets are based on average performance which indicates that network performance is significantly better than the MSS targets in the last two years. The AER agrees with PB that as Ergon Energy has set its internal targets at a level that requires significantly better performance than the STPIS targets, Ergon Energy is ensuring that its service performance will outperform the STPIS targets.

The AER also notes PB's advice that Ergon Energy's internal targets (and the likely service performance) are consistent with its forecast expenditure. Ergon Energy is being funded to provide services at a superior level to the MSS.

As Ergon Energy proposed that its STPIS performance targets be aligned with MSS targets (rather than the internal targets on which its forecast expenditure is based), Ergon Energy would effectively be funded through its expenditure allowances to outperform the STPIS targets. The result being that it would receive a benefit under the STPIS for improving performance where this improved performance has already been funded through its expenditure allowances. This would be contrary to clause

[894] Ergon Energy, *Regulatory proposal*, July 2009, p. 400.

3.2.1(a)(1) of the STPIS which states that performance targets should be modified to account for completed or planned reliability improvements and any other factor expected to affect network reliability performance.

Accordingly, the AER does consider that Ergon Energy’s proposed approach to set targets based on the MSS is inappropriate as it does not satisfy clause 3.2.1(a)(1) of the STPIS. The AER will set performance targets for Ergon Energy for the next regulatory control period based on Ergon Energy’s internal targets and are as set out at table 12.7.

Consistent with the recommendations by PB, the AER will set the target for the telephone answering parameter for Ergon Energy at 77.3 per cent for each year of the next regulatory control period.

Table 12.7: AER performance targets for Ergon Energy – 2010–11 to 2014–15

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
Urban	minutes	129	128	127	127	126
Short rural	minutes	296	291	287	283	279
Long rural	minutes	699	687	675	664	652
SAIFI						
Urban	per 0.01 interruptions	169	1.68	1.66	1.64	1.63
Short rural	per 0.01 interruptions	3.06	3.02	2.98	2.94	2.91
Long rural	per 0.01 interruptions	5.59	5.52	5.44	5.37	5.29
Customer service						
Telephone answering	percentage	77.3	77.3	77.3	77.3	77.3

12.8 AER conclusion

The AER has determined that it will apply a STPIS to the Qld DNSPs for the next regulatory control period in accordance with clause 6.6.2(a) of the NER. In determining the STPIS to apply, the AER has reviewed the Qld DNSPs’ regulatory proposals, PB’s advice, relevant submissions and has had regard to clause 6.6.2(b) and the transitional provisions of the NER. The AER concludes that:

- it will apply the SAIDI and SAIFI reliability of supply parameters to the Qld DNSPs

- it will apply the telephone answering customer service parameter to Ergon Energy but will not apply it to Energex due to concerns about its available data

- there are no quality of supply parameters to apply under the STPIS but the Qld DNSPs will be required to collect and report on the quality of supply

- the components and parameters of the STPIS applicable to Energex are as set out at table 12.3

- the components and parameters of the STPIS applicable to Ergon Energy are as set out at table 12.2

- a cap on overall revenue at risk of ±2 per cent is consistent with the objectives of the STPIS and satisfies the criteria set out at clause 6.6.2(b)(3) of the NER and the transitional requirements under the NER

- a cap on revenue at risk of ±0.2 per cent to Ergon Energy for the telephone answering customer service parameter will apply in accordance with clause 5.2(b) of the STPIS

- it will apply incentive rates for the next regulatory control period in accordance with clause 3.2.2 and appendix B of version 01.2 the STPIS, for the reliability of supply component, as set out in table 12.4 (Energex) and table 12.5 (Ergon Energy)

- an incentive rate of –0.040 per cent will apply to Ergon Energy's telephone answering parameter as set out at 5.3.2(a)(1) of the STPIS

- it will not apply the GSL component of the STPIS to the Qld DNSPs while the GSL scheme administered by the QCA remains in place. If at any time in the next regulatory control period the QCA ceases to apply a GSL scheme, the AER will apply the GSL component of the STPIS (set out at section 6 of the STPIS) from the date the jurisdictional scheme is withdrawn

- the approach proposed by Energex to set performance targets satisfies the criteria that the AER must consider in setting performance under clause 3.2.1(a)(1) of the STPIS. The performance targets to apply to Energex are as set out at table 12.6

- the approach proposed by Ergon Energy to set performance targets based on the MSS targets does not satisfy the criteria set out at clause 3.2.1(a)(1) of the STPIS. The AER instead has set performance targets based on Ergon Energy's internal targets. The performance targets to apply to Ergon Energy are as set out at table 12.7.

12.9 AER draft decision

In accordance with clause 6.12.1(9) of the NER, the AER has determined that the national distribution STPIS will apply to Energex in the next regulatory control period in the following form:

1. the applicable component and parameters are the SAIDI and SAIFI reliability of supply parameters. The AER will not apply the telephone answering customer service parameter to Energex
2. overall revenue at risk is ±2 per cent
3. the incentive rates to apply to each applicable parameter were calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of version 01.2 of the STPIS, as set out in table 12.4 of this draft decision
4. that the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period as set out at table 12.6 of this draft decision
5. the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn the AER will implement such a scheme from the day the jurisdictional scheme is withdrawn.

In accordance with clause 6.12.1(9) of the NER, the AER has determined that the national distribution STPIS will apply to Ergon Energy in the next regulatory control period in the following form:

1. the applicable component and parameters are the SAIDI and SAIFI reliability of supply parameters. The AER will apply the telephone answering customer service parameter to Ergon Energy
2. overall revenue at risk is ±2 per cent and ±0.2 per cent for the telephone answering parameter
3. the incentive rates to apply to each applicable parameter were calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of version 01.2 of the STPIS, as set out in table 12.5 of this draft decision
4. that the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period as set out at table 12.7 of this draft decision
5. the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn the AER will implement such a scheme from the day the jurisdictional scheme is withdrawn.

13 Efficiency benefit sharing scheme

13.1 Introduction

This chapter sets out how the AER intends to apply its efficiency benefit sharing scheme (EBSS) to the Qld DNSPs. The EBSS shares between DNSPs and distribution network users the efficiency gains or losses derived from the difference between a DNSP's actual opex and the forecast opex allowance for a regulatory control period.

In accordance with clause 6.5.8(a) of the NER, the AER has published an EBSS which establishes a scheme that will apply to the Qld DNSPs from 1 July 2010.[895]

In its framework and approach paper, the AER decided that its likely approach for the Qld DNSPs' distribution determinations would be to apply the national EBSS during the next regulatory control period.[896] However, the scheme will not have a direct financial impact until the 2015–20 regulatory control period when the Qld DNSPs will receive carryover benefits/penalties for efficiency gains or losses realised during the next regulatory control period.

13.2 Regulatory requirements

Under clause 6.5.8(c) of the NER, the AER must have regard to the following factors when implementing the EBSS:

> (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.

Transitional arrangements

The transitional provisions in the NER preclude the use of a capex component in the EBSS for the Qld DNSPs during the next regulatory control period. Clause 11.16.4 of the NER states:

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[895] AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008.

[896] AER, *F*inal f*ramework and approach paper: Application of schemes*, November 2008.

(a) An efficiency benefit sharing scheme for ENERGEX and Ergon Energy for the regulatory control period must not cover efficiency gains and losses relating to capital expenditure.

(b) For the purposes of clause 6.5.8(c) the AER must also have regard to the continuing obligations on ENERGEX and Ergon Energy throughout the regulatory control period to implement the recommendations from the EDSD Review adopted by the Queensland Government.[897]

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.

[897] Queensland Department of Natural Resources, Mines and Energy, *Detailed Report of the Independent Panel, Electricity Distribution and Service Delivery for the 21st Century*, July 2004. The EDSD Review assessed the performance of Queensland's electricity distribution networks, identifying a number of shortcomings in regard to the DNSPs' service standards and expenditure programmes. The EDSD Review set out a number of recommendations to alleviate these problems and ensure the future reliability of electricity supply to Queensland customers in an environment of high growth in maximum energy demand. In doing so, it foreshadowed the need for levels of capex and opex significantly above previous regulatory allowances.

Final year formula

As the distribution determination for the 2015–20 regulatory control period will be made prior to the completion of the next regulatory control period, the AER will estimate the actual opex required to calculate gains or losses for the final year of the next regulatory control period 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 2015–20 regulatory control period (E_6) will be adjusted as follows:

$$E_6 = (F_6 - A_6) - (F_5 - A_5) + (F_4 - A_4)$$

Other provisions

The EBSS also provides for:

- adjustments to forecast opex allowances for the purpose of calculating carryover amounts to account for variations between forecast and outturn demand growth and changes to a DNSP’s capitalisation policies
- DNSPs to propose cost categories to be excluded from the operation of the EBSS
- the AER, in accordance with the distribution consultation procedures, to amend or replace an EBSS (clause 6.5.8(d) of the NER).

13.3 Qld DNSP regulatory proposals

For the purposes of calculating EBSS carryover amounts, the forecast opex must be adjusted for the cost consequences of changes in a DNSPs’ capitalisation policy and differences between forecast and actual demand growth over the next regulatory control period. Energex and Ergon Energy did not propose any specific adjustment mechanisms for changes to capitalisation policies or differences between forecast and actual demand growth for the next regulatory control period.

The EBSS also allows DNSPs to propose additional cost categories to be excluded from the operation of the EBSS. The Qld DNSPs proposed a range of costs to be excluded from the EBSS, including:[898]

- debt and equity raising costs
- insurance and self insurance costs
- the demand management innovation allowance (DMIA).

The Qld DNSPs did not propose to exclude any specific costs associated with the continuing obligations to implement the recommendations of the Electricity

[898] Energex, *Regulatory proposal*, July 2009, p. 249; and Ergon Energy, *Regulatory proposal*, July 2009, p. 395.

Distribution and Service Delivery Review (EDSD Review).[899] Ergon Energy, however, proposed that the AER should have regard to a number of elements of the EDSD Review in assessing its proposals in relation to the EBSS.

13.4 Submissions

No submissions were received on this matter.

13.5 Issues and AER considerations

13.5.1 Demand growth adjustment and capitalisation policy

In developing the EBSS, the AER recognised that a DNSP's opex may be affected by the level of demand growth experienced in a network and changes in a DNSP's capitalisation policy.[900] The EBSS provides that forecast opex is to be adjusted for variances between actual and forecast demand growth over the regulatory control period and changes in capitalisation policy, for the purposes of calculating carryover amounts. However, as the AER may make a decision about how to apply the EBSS to a particular DNSP, it may decide not to make such adjustments.[901]

Qld DNSP proposals

The Qld DNSPs did not propose any forecast opex adjustment mechanisms to account for changes to capitalisation policies or differences between forecast and actual demand growth for the next regulatory control period.

Ergon Energy submitted that if its capitalisation policy changes prior to, or during, the next regulatory control period, it will:[902]

- adjust the forecast opex used to calculate the carryover amounts so that the forecast opex is consistent with the capitalisation changes
- provide the AER with a detailed description of any changes to the capitalisation policy and a calculation of the impact of those changes on forecast and actual opex.

Ergon Energy also submitted that it will advise the AER at the end of the next regulatory control period if it considers that, for the purposes of calculating the carryover amounts for the 2015–2020 regulatory control period, any adjustments are required to its forecast opex for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period.[903]

Energex submitted that, should there be any changes to its capitalisation policy during the next regulatory control period, those changes will be taken into account in the

899 Queensland Department of Natural Resources, Mines and Energy, *EDSD Review*, July 2004.
900 AER, *Final decision, Electricity DNSPs EBSS*, June 2008, p. 6.
901 NER, clause 6.12.1(9).
902 Ergon Energy, *Regulatory proposal*, July 2009, p. 394.
903 Ergon Energy, *Regulatory proposal*, July 2009, p. 394.

assessment of carryover gains and losses to be applied in the 2015–20 regulatory control period.[904]

AER considerations

The AER does not consider that a demand growth adjustment is necessary for the EBSS to provide DNSPs with a continuous incentive to pursue efficiency gains. The demand growth adjustment was incorporated into the EBSS to prevent DNSPs from being penalised or rewarded by the EBSS for changes in demand growth over which the DNSP has no control.[905] As the risk to DNSPs of being rewarded or penalised by the EBSS for changes in demand growth is symmetrical, the AER considers that efficiency carryovers need not be adjusted for changes in outturn demand growth.

Given that the Qld DNSPs did not propose demand growth adjustment mechanisms, the AER will not adjust the EBSS carryover for the consequences of changes in demand growth during the next regulatory control period.

In their regulatory proposals, the Qld DNSPs do not anticipate changes to their capitalisation policies during the next regulatory control period. However, prior to the 2015–20 regulatory control period, the AER will consider adjustments to future carryover amounts for the Qld DNSPs if it is advised of any changes to capitalisation policies affecting actual opex during the next regulatory control period.

13.5.2 Excluded cost categories

The EBSS provides for a range of adjustments and cost exclusions in the calculation of efficiency carryover amounts.[906] In addition, the EBSS allows DNSPs to propose additional cost categories to be excluded from the EBSS.[907] The scheme requires that these cost categories must be proposed by a DNSP in its regulatory proposal for the next regulatory control period.[908]

Qld DNSP regulatory proposals

Both Energex and Ergon Energy proposed that recognised pass through events and opex for non–network alternatives should be excluded for the purpose of calculating the EBSS.[909] In addition, Energex proposed that the following costs also be excluded for the purposes of the EBSS:[910]

- debt and equity raising costs
- insurance costs
- self insurance costs.

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904 Energex, *Regulatory proposal*, July 2009, p. 249.
905 AER, *Final decision, Electricity DNSPs EBSS* ,June 2008, p. 5.
906 AER, *Final decision, Electricity DNSPs EBSS*, June 2008, pp. 6–7.
907 AER, *Final decision, Electricity DNSPs EBSS*, June 2008, p. 5.
908 AER, *Final decision, Electricity DNSPs EBSS*, June 2008, p. 5.
909 Energex, *Regulatory proposal*, July 2009, p. 249; and Ergon Energy, *Regulatory proposal*, July 2009, p. 395.
910 Energex, *Regulatory proposal*, July 2009, p. 250.

Ergon Energy proposed that the following costs also be excluded for the purposes of the EBSS:[911]

- the DMIA
- self insurance costs.

Ergon Energy did not explicitly identify debt and equity raising costs as a category to be excluded from the EBSS, however, it did exclude these costs from its opex forecast for the next regulatory control period, for EBSS purposes.[912]

AER considerations

The AER considers two key factors when assessing whether an opex category should be excluded from the EBSS. The first factor is whether or not the opex is controllable. The AER does not consider it appropriate for DNSPs to receive benefits or penalties through the EBSS for variances in its opex for cost categories over which it has no control.[913]

The second factor is how actual expenditure for that cost category is used in setting opex forecasts for the following regulatory control period. The EBSS assumes that actual opex is used as a basis for setting future opex allowances. If this is not the case, for instance if opex forecasts for a given cost category were based on an external benchmark, the EBSS would not provide a continuous incentive to reduce opex.

Applying these factors, the AER considers it appropriate to exclude the following additional forecast opex costs, to the extent approved by the AER in its distribution determination, from the operation of the EBSS for Energex and Ergon Energy for the next regulatory control period:

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

These excluded costs will be recognised in addition to the adjustments set out in section 2.3.2 of the EBSS, which include non–network alternatives and recognised cost pass through events.

The AER considers it appropriate that approved forecast debt raising costs be excluded from the operation of the EBSS, on the basis that forecast costs are based on a benchmark efficient firm rather than the historical costs of the DNSP, and are

911 Ergon Energy, *Regulatory proposal*, July 2009, p. 396.
912 Ergon Energy, *Regulatory proposal*, July 2009, p. 396.
913 This approach is consistent with clause 6.5.8(c)(2) of the NER which requires the EBSS to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex. There is no incentive for DNSPs to reduce opex for cost categories over which they have no control.

therefore beyond the control of the DNSP. Similarly, self insurance and insurance cost forecasts are based on independent expert analysis. Consequently, the AER considers it reasonable that approved forecasts of these costs also be excluded from the EBSS.

The AER also considers that it would be inappropriate to include equity raising costs in the EBSS because, like debt raising costs, forecast equity raising costs are based on a benchmark efficient firm rather than the historical costs of the Qld DNSPs. To the extent that benchmark cash flow analysis, based on the capex allowance, demonstrates that a DNSP should be provided with an allowance for equity raising costs, the AER considers that the allowance should be amortised. In this draft decision the AER maintains that any equity raising allowance determined for the Qld DNSPs will be added to the DNSP's RAB and depreciated over the weighted average standard life of its assets. Consequently, equity raising costs are already excluded from the operation of the EBSS as they are not a component of the Qld DNSPs' forecast opex allowances.

The DMIA developed by the AER, in accordance with clause 6.6.3 of the NER, provides a DNSP an annual, ex–ante allowance in the form of a fixed amount of additional revenue at the commencement of each year of the next regulatory control period. As such, the DMIA is not a controllable cost. On this basis, the AER considers it reasonable that the DMIA be excluded from the operation of the EBSS.

The AER notes that many DNSP employees are members of defined benefit superannuation schemes. Consequently, a DNSP's superannuation liabilities relating to these employees are affected by, among other things, the number of employees that retire in a given year, and the performance of the superannuation fund. Given that both of these factors are beyond the control of the DNSP, the AER considers it reasonable that the approved amount of superannuation costs be excluded from the EBSS.

13.5.3 Transitional arrangements

The Qld DNSPs acknowledged that, consistent with clause 11.16.4(a) of the NER, the EBSS will not recognise capex efficiencies for the next regulatory control period.

The transitional provisions of the NER preclude the use of a capex component in the EBSS for the Qld DNSPs. They also require the AER to have regard to the continuing obligations on Energex and Ergon Energy to implement the recommendations from the EDSD Review.[914]

Qld DNSP regulatory proposals

The Qld DNSPs did not propose to exclude specific costs associated with the continuing obligations to implement the recommendations of the EDSD Review from the EBSS.

Ergon Energy submitted that while it generally accepts the AER's application of an EBSS to the Qld DNSPs, it stated the AER should have regard to the EDSD Review

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914 NER, clauses 11.16.4(a) and (b).

outcomes. Specifically, Ergon Energy submitted that it was the intention of the EDSD Review that:[915]

- Ergon Energy's actual expenditure during a regulatory control period should not be artificially constrained by the building blocks approved by the regulator;
- Ergon Energy should be free to spend what is necessary to meet its service obligations to its customers; and
- Ergon Energy should not be unreasonably penalised for exceeding the 'building block' allowances.

AER considerations

The Qld DNSPs acknowledged that the EBSS will not recognise capex efficiencies for the next regulatory control period, consistent with clause 11.16.4(a) of the NER. This approach is also consistent with the national EBSS.

As the Qld DNSPs did not propose any specific opex cost exclusions relating to the outcomes of the EDSD Review, the AER will not exclude these costs from the EBSS. The recommendations of the EDSD Review do not represent binding legal or regulatory obligations for the Qld DNSPs although they have been considered by the AER as part of this draft determination in accordance with clause 11.16.4 of the NER. As such, any opex incurred by Energex or Ergon Energy in responding to these recommendations is considered discretionary and controllable, and should be included in the calculation of future EBSS carryovers.

The AER considers that its approach to assessing the expenditure matters raised by Ergon Energy in relation to the EDSD Review is consistent with that proposed by Ergon Energy. In particular, the forecast opex for each regulatory year in the EBSS is based on the AER's determination of efficient opex levels for the next regulatory control period to meet the opex objectives, which include service level obligations. The AER has considered the recommendations of the EDSD Review in its determination of efficient forecast opex allowances for both Qld DNSPs for the next regulatory control period.

13.6 AER conclusion

The AER will apply the EBSS in accordance with its framework and approach paper for Energex and Ergon Energy published in November 2008. As Energex and Ergon Energy did not propose an ex–post demand growth adjustment method, the AER will not adjust the EBSS for the consequences of changes in demand growth for Energex or Ergon Energy for the next regulatory control period.

The following opex cost categories, to the extent approved by the AER in the distribution determination, will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs

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915 Ergon Energy, *Regulatory proposal*, July 2009, p. 94.

- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the DMIA.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS.

The AER's controllable opex forecasts for the Qld DNSPs are outlined in tables 13.1 and 13.2 and will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[916] The derivations of the AER's controllable opex forecasts for the Qld DNSPs are outlined in chapter 8 of this draft decision. The opex forecasts will be adjusted for approved pass throughs during the next regulatory control period.

Table 13.1: AER conclusion on Energex's controllable opex for EBSS purposes ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Total opex	313.2	312.2	318.0	324.4	318.7
Adjustment for debt raising costs	4.2	4.6	5.1	5.5	6.0
Adjustment for insurance costs	3.8	3.8	3.8	3.8	3.7
Adjustment for self insurance costs	0.008	0.008	0.008	0.008	0.008
Adjustment for non–network alternatives	3.4	3.5	3.5	3.5	3.4
Adjustment for superannuation	n/a	n/a	n/a	n/a	n/a
Adjustment for DMIA	1.0	1.0	1.0	1.0	1.0
Opex for EBSS purposes	300.8	299.3	304.6	310.6	304.6

916 AER, *Final decision*, *Electricity DNSPs EBSS*, June 2008, pp. 5–7.

Table 13.2: AER conclusion on Ergon Energy's controllable opex for EBSS purposes ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Total opex	320.5	319.2	304.8	293.6	276.1
Adjustment for debt raising costs	3.8	4.0	4.4	4.7	5.1
Adjustment for self insurance costs	0.003	0.003	0.003	0.003	0.003
Adjustment for non–network alternatives	11.2	11.8	12.3	11.9	11.9
Adjustments for insurance	n/a	n/a	n/a	n/a	n/a
Adjustments for superannuation	n/a	n/a	n/a	n/a	n/a
Adjustment for DMIA	1.0	1.0	1.0	1.0	1.0
Opex for EBSS purposes	304.5	302.4	287.1	276.0	258.1

13.7 AER draft decision

In accordance with clause 6.12.1(9) of the NER, the EBSS to apply to Energex is as set out in the AER's *Final Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15*, published in November 2008.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the demand management innovation allowance.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS, which include non–network alternatives and recognised pass through events.

In accordance with clause 6.12.1(9) of the NER, the EBSS to apply to Ergon Energy is as set out in the AER's *Final Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15*, published in November 2008.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the demand management innovation allowance.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS, which include non–network alternatives and recognised pass through events.

In accordance with clause 6.3.2(a)(3) of the NER, the EBSS to apply to the Qld DNSPs is as specified in section 13.6 of this draft decision.

14 Demand management incentive scheme

14.1 Introduction

This chapter sets out the AER's demand management incentive scheme (DMIS) to apply to the Qld DNSPs for the next regulatory control period. The objective of the DMIS is to provide incentives for DNSPs to pursue and implement efficient and innovative non-network solutions to address growing demand and constraints on distribution networks. The DMIS operates in conjunction with existing incentives in the regulatory framework in pursuit of these objectives. Demand management refers to measures undertaken by a DNSP to meet consumer demand by shifting or reducing demand rather than increasing supply.

On 17 October 2008, the AER published its DMIS to apply to the Qld DNSPs for the next regulatory control period.[917] In its November 2008 framework and approach paper, the AER set out its likely approach to applying its DMIS to the Qld DNSPs.[918] The approach was to apply Part A of the scheme, the demand management innovation allowance (DMIA) to the Qld DNSPs.[919] The DMIA was capped at $5 million for each of the Qld DNSPs over the next regulatory control period, to be allocated in five equal annual instalments of $1 million.

This chapter reviews the issues raised by the Qld DNSPs and sets out the AER's considerations and conclusions on how the DMIS will apply to the Qld DNSPs during the next regulatory control period.

14.2 Regulatory requirements

Clause 6.6.3 (a) of the NER provides 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.

The AER published the DMIS to apply to Qld DNSPs for the next regulatory control period.[920] A decision on how the DMIS will apply to a DNSP is a constituent decision of the 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.

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[917] AER, *Demand management incentive scheme – Energex, Ergon Energy and ETSA Utilites 2010–15*, October 2008.
[918] AER, *Final framework and approach paper: Application of schemes*, November 2008.
[919] AER, *Final framework and approach paper: Application of schemes*, November 2008.
[920] AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008.

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.

14.3 Queensland DNSP regulatory proposals

14.3.1 Application of the DMIS

Energex

Energex stated that it accepts the AER's position, as set out in the relevant framework and approach paper, to apply the DMIS in the form of a DMIA capped at $5 million for the next regulatory control period. However, it stated that this acceptance was subject to the AER accepting Energex's proposed demand management strategy and programs outlined in chapter 5 of its regulatory proposal.[921]

Energex stated that it had included an amount of $1 million as an annual increment for each regulatory year of the next regulatory control period within its building block revenue requirement.[922]

Ergon Energy

Ergon Energy stated that it supports the AER's position as set out in the relevant framework and approach paper to apply the DMIS in the form of a DMIA capped at $5 million for the next regulatory control period. Ergon Energy stated it has included a revenue increment of $1 million for the DMIS in its calculation of its annual revenue requirement for each regulatory year of the next regulatory control period.[923]

14.4 Submissions

The AER received submissions from the Energy Users Association of Australia (EUAA)[924] and the Queensland Council of Social Service (QCOSS).[925] The matters raised in these submissions relate to the AER's assessment of demand management projects proposed by the Qld DNSPs as part of their forecast capex and opex. As such the submissions are considered in chapters 7 and 8 of this distribution determination, respectively.

14.5 Issues and AER considerations

14.5.1 Application of the DMIS

Energex

The AER notes that Energex has indicated its acceptance of the DMIS as set out in the framework and approach.

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921 Energex, *Regulatory proposal*, July 2009, p. 252.
922 Energex, *Regulatory proposal*, July 2009, p. 269.
923 Ergon Energy, *Regulatory proposal*, July 2009, p. 410.
924 EUAA, *Submission to the AER*, 28 August 2009.
925 QCOSS, *Response to Queensland DNSPs*, August 2009.

The AER also notes Energex's comments that its acceptance of the AER's approach to the DMIS was subject to the proposed demand management strategy and programs outlined in chapter 5 of its proposal being accepted. The AER sought clarification from Energex on this statement.[926] In its response to the AER, Energex stated that in the event that the AER decides on opex forecasts and allowances different from those proposed by Energex, there would be flow on effects to the progression of demand management initiatives.[927]

The AER considers that any matter concerning Energex's forecast opex, including any demand management projects therein, is not a consideration under the DMIS. These matters are assessed by the AER under clause 6.5.6 of the NER.[928]

Any flow on effects from the AER's opex assessment on the selection of demand management projects that Energex submit for funding approval under the DMIA, is a matter for Energex to consider. The DMIA is provided to DNSPs in the form of an ex–ante allowance, with no ex–ante approval of particular projects by the AER.[929] At the end of each regulatory year of the next regulatory control period, the AER will conduct a review of expenditure incurred by Energex in the preceding regulatory year to assess for compliance with the DMIA criteria, as set out in the scheme.[930]

The AER is not required to assess the eligibility of demand management projects for the DMIA as part of this distribution determination. The DMIS allows Energex to select an expenditure profile over the regulatory control period that it prefers, and DMIA approval is not dependent upon the probability of a project's success.[931]

Finally, the AER confirms that Energex has included annual increments of $1 million to their annual revenue requirement for each year of the next regulatory control period. Consistent with a capped allowance, only CPI escalation will be permitted on the allowance to maintain it in real terms.

Ergon Energy

Ergon Energy has not proposed any alteration to the DMIS applying to it, as set out in the framework and approach paper.

The AER confirms that Ergon Energy has included annual increments of $1 million to the calculation of their annual revenue requirement for the next regulatory control period. Consistent with a capped allowance, only CPI escalation will be permitted on the allowance to maintain it in real terms.

14.6 AER conclusion

The AER maintains its decision to apply Part A (that is, the DMIA) to the Qld DNSPs, as outlined in the framework and approach paper. The DMIA will be capped

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926 AER, email request, issue number: AER.EGX.06, 20 August 2009.

927 Energex, email response, issue number: AER.EGX.06, 24 August 2009.

928 See also clause 6.4.3(a)(7) of the NER which clearly differentiates between the DMIS and forecast opex.

929 AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, p. 3.

930 AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, p. 8.

931 AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, pp. 5–8.

at $5 million for each business over the next regulatory control period. The capped amount will be allocated to each business as an ex–ante annual allowance of $1 million, for each year of the next regulatory control period as part of this draft decision.

The ex–post review and operation of the DMIA will be as set out in the DMIS.

14.7 AER draft decision

In accordance with clause 6.12.1(9) of the NER, the DMIS to apply to Energex is the DMIS set out in the AER's document, *Demand management incentive scheme - Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

The AER decides that Part A of the DMIS (that is, the DMIA) will apply to Energex. The DMIA is capped at $5 million for the next regulatory control period and allocated to Energex in equal annual instalments of $1 million for each year of the next regulatory control period, as specified in section 14.6 of this draft decision.

In accordance with clause 6.12.1(9) of the NER, the DMIS to apply to Ergon Energy is the DMIS set out in the AER's document, *Demand management incentive scheme - Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

The AER decides that Part A of the DMIS (that is, the DMIA) will apply to Ergon Energy. The DMIA is capped at $5 million for the next regulatory control period and allocated to Ergon Energy in equal annual instalments of $1 million for each year of the next regulatory control period, as specified in section 14.6 of this draft decision.

15 Pass through arrangements

15.1 Introduction

This chapter sets out the AER's assessment of the Qld DNSPs' proposed pass through events to apply during the next regulatory control period.

An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks properly and incurs additional costs it would be expected to bear those costs. However, the NER recognises that a DNSP can be exposed to risks beyond its control and which may have a material impact on its costs.

One means of dealing with such outcomes is the pass through provisions contained in the NER. These provisions allow uncontrollable material changes (both increases and decreases) in the costs of providing direct control services to be passed through to distribution network users during a regulatory control period. This pass through of costs is achieved through an amendment to the price or revenue determination.

15.2 Regulatory requirements

The definition of a pass through event is set out in chapter 10 of the NER:

> Any of the following is a pass through event:
>
> (a) a regulatory change event;
>
> (b) a service standard event;
>
> (c) a tax change event;
>
> (d) a terrorism event.
>
> …
>
> An event nominated in a distribution determination as a pass through event is a pass through event for the determination (in addition to those listed above).

Pass through events can be both positive and negative. A positive change event is a pass through event that materially increases the costs of providing direct control services. If this occurs a DNSP may seek the approval of the AER to pass through to distribution network users a positive pass through amount under clause 6.6.1(a) of the NER.

A negative change event is a pass through event that materially reduces the costs of providing direct control services. If this occurs a DNSP must notify the AER of the matters set out in clause 6.6.1(f) of the NER, including the details of the event and the negative pass through amount. After becoming aware that a negative change event has occurred and the AER imposes a requirement on the DNSP in relation to the negative change event, the AER must determine a negative pass through amount under clause 6.6.1(g) of the NER.

Pass through adjustments within the regulatory control period

Clause 6.6.1 of the NER outlines the procedure for making pass through adjustments after the making of a distribution determination.

If it is determined that a pass through event has occurred the AER must determine the pass through amount and how that amount is to be recovered over the remainder of the regulatory control period. The factors that the AER is required to take into account in determining the pass through amount are contained in clause 6.6.1(j) of the NER.

Transitional arrangements

The NER provides for a transitional arrangement for Qld DNSPs with respect to events that the 2005 QCA determination defined as pass through events. Clause 11.16.9 of the NER states:

> (a) If an event or circumstance occurs before 1 July 2010 which would constitute a pass through under the 2005 determination and no application for a pass through has been made in relation to that event or circumstance, ENERGEX or Ergon Energy may apply to the AER within a year of the event or circumstance occurring to accommodate the impact of the event in the regulatory control period.
>
> (b) The AER must allow a pass through of such amounts if the event or circumstance would have constituted a pass through under the 2005 determination as if the amounts were approved pass through amounts under clause 6.6.1.

15.3 Queensland DNSP regulatory proposals

15.3.1 Energex

Energex proposed nominated pass through events in accordance with the AER's classification of such events in the ACT and NSW distribution determinations as:

- specific nominated events
- a general nominated pass through event.

Specific nominated events

Energex proposed the following ten events and definitions:[932]

> **Feed–in tariff event**: the payment by Energex of a feed-in tariff for electricity produced by photovoltaic generators where such payment is made in the 2010–15 regulatory control period and has not been included in capital or operating expenditure forecasts included in this Regulatory Proposal.
>
> **Smart meter event:** the imposition of an obligation on Energex to install smart meters for some or all of its customers, or to conduct large scale metering trials, during the course of the 2010–2015 regulatory control period, regardless of whether the requirement takes the form of a statutory obligation or not or is imposed before or after the commencement of the 2010–2015 regulatory control period, where that requirement:

[932] Energex, *Regulatory proposal*, July 2009, appendix 20.2.

(a) falls within no other category of pass through event; and

(b) materially increases the costs of providing direct control services.

CPRS event: the imposition of an obligation on Energex to acquit carbon permits which arises from the introduction of, or change to a carbon emissions trading scheme during the course of the 2010–15 regulatory control period, where that scheme is imposed by the Commonwealth or the State of Queensland and the relevant obligation:

(a) falls within no other category of pass through event; and

(b) increases the costs of providing direct control services.

OH&S event: the imposition of obligations on Energex which arise from the introduction of or a change to the OH&S Model Act, regardless of whether the obligations are imposed before or after the commencement of the 2010–15 regulatory control period, where those obligations:

(a) fall within no other category of pass through event; and

(b) materially increase or materially decrease the costs of providing direct control services.

Henry Review event: the imposition of tax changes on Energex arising from the implementation of recommendations of the Henry Review, regardless of whether the tax changes are imposed before or after the commencement of the 2010–15 regulatory control period, where those tax changes:

(a) fall within no other category of pass through event; and

(b) materially increase or materially decrease the costs of providing direct control services.

RIO reporting event: the incurring of costs by Energex, during the course of the 2010–15 regulatory control period, to implement the systems and processes that are required to enable Energex to comply with the AER's regulatory reporting requirements under a Regulatory Information Order (RIO), where those requirements:

(a) are imposed before or after the commencement of that regulatory contol period; and

(b) fall within no other category of pass through event

and the costs so incurred by Energex are material.

NECF event: The incurring of costs by Energex, during the course of the 2010–15 regulatory control period, as a result of the implementation in Queensland of a national framework for regulating the sale and supply of electricity to retail customers, where the requirements under that framework:

(a) are imposed before or after the commencement of that regulatory control period; and

(b) fall within no other category of pass through event,

and the costs so incurred by Energex are material.

> **National Broadband Network (NBN) event**: The imposition of requirements on Energex, regardless of whether the requirements are imposed before or after the commencement of the 2010–15 regulatory control period and whether they are imposed under statute, contract or otherwise, to install or maintain a broadband network as part of Energex's distribution system in order to facilitate the Commonwealth Government's proposed national broadband network, where the requirements:
>
> (a) fall within no other category of pass through event; and
>
> (b) materially increase or materially decrease the costs of providing direct control services.
>
> **GSL event**: the incurring of costs by Energex, during the course of the 2010–15 regulatory control period, to implement the changes to systems and processes that are required to enable Energex to pay GSLs under the EIC where the requirements relating to the payment of those GSLs:
>
> (a) are changed before or after the commencement of that regulatory control period; and
>
> (b) fall within no other category of pass through event.
>
> and the costs so incurred by Energex are material.
>
> **Storm disaster event**: The incurring of costs by Energex as a result of a storm during the course of the 2010-2015 regulatory control period to the extent those costs exceed $10 million.

Events to be treated as general nominated pass through events

Energex stated that the following events should be treated as general nominated events for the purposes of Energex's regulatory proposal:[933]

- force majeure
- earthquakes above the magnitude of five
- compliance event/functional change/changes in reporting requirements
- distribution loss event
- electric magnetic fields event
- insurance event
- retailer of last resort
- joint planning event
- events for which self insurance allowances were rejected.

[933] Energex, *Regulatory proposal*, July 2009, p. 294.

Energex noted that the AER had indicated in its distribution determination for NSW DNSPs that these events may constitute a general nominated event.[934] Energex also proposed that a customer connection event, which was considered by the AER in the distribution determination for NSW DNSPs, should be treated as a general nominated event for the purposes of Energex's regulatory proposal.[935]

In addition to the events noted above, Energex submitted that the AER should consider that the following events may constitute general nominated pass through events:[936]

- *Interim change events*: Energex proposed that events could occur in the current regulatory control period, the cost impact of which would occur in the next regulatory control period and that these events could cause a material change in the cost of providing distribution services. Energex submitted that the AER should consider that interim change events may constitute general nominated pass through events.

- *Retailer credit risk event*: Energex submitted that as a distribution–only business, it is now more exposed to retailer credit risk under contractual arrangements in Queensland, which provide for retailers to bill customers for DUOS charges on behalf of distributors. Energex's self insurance for retailer credit risk is limited to amounts up to $5 million and Energex submitted that the AER should consider that retailer credit risk events for amounts greater than $5 million may constitute general nominated pass through events.

Materiality

In respect of specific nominated events, Energex submitted that a materiality threshold commensurate with the cost of assessing the pass through application was appropriate and proposed a threshold of $200 000 for some of the specific nominated events outlined in the Energex proposal.[937]

Energex also noted the AER's previous decision that the appropriate materiality threshold for the general pass through event was 1 per cent of the smoothed revenue allowance specified in the final decision in the years of the regulatory control period that the costs are incurred. Energex argued that the exclusive use of this threshold was unreasonable and unfair to DNSPs that have high revenues. Energex proposed that for general nominated pass through events, the materiality threshold should be defined as 1 per cent of average annual revenue or a fixed amount of $5 million, whichever is lower.[938]

Energex disagreed with the application of the materiality threshold to the smoothed revenue allowance in the year in which the costs of the pass through event are incurred. Energex argued that pass through events generally do not occur in one year, but are spread across a period of time and that the application of the materiality

934 Energex, *Regulatory proposal*, July 2009, p. 67.
935 Energex, *Regulatory proposal*, July 2009, p. 294.
936 Energex, *Regulatory proposal*, July 2009, p. 295.
937 Energex, *Regulatory proposal*, July 2009, pp. 285–295.
938 Energex, *Regulatory proposal*, July 2009, p. 296.

threshold to annual revenue was arbitrary. Energex proposed that the materiality threshold be applied to the total cost of the pass through event, rather than annual revenue.[939]

Alternative control services

Energex proposed that the pass through provisions for the defined events and nominated events should be applied to both standard control and alternative control services.[940]

Pass through clause

Energex included a clause setting out the process to be followed upon occurrence of a pass through event, including the manner in which the AER will assess an application for a cost pass through. The clause was very similar to the requirements of clause 6.6.1 of the NER, with the exception that the clause contained a definition of materiality not contained in the NER.[941]

15.3.2 Ergon Energy

Events proposed as regulatory change events

Ergon Energy proposed eight events to be considered as regulatory change events.

Change to minimalist transitioning approach

Under the current Queensland regulatory framework, Ergon Energy is permitted to operate under a 'minimalist transitioning approach' regarding providing National Metering Identifier (NMI) information and populating Market Settlement and Transfer Solution for the purposes of full retail competition in Queensland. Under this approach, Ergon Energy is permitted to respond manually to retailer requests for NMI information, rather than implementing an automated process. The use of the minimalist transitioning approach is reviewed annually by the QCA and if Ergon Energy was no longer permitted to use the approach, it would be required to install an automated system for providing NMI information, which would result in additional costs. Ergon Energy sought AER approval that the removal or significant amendment of the approach would constitute a regulatory change event.[942]

Introduction of smart meters

Ergon Energy defined a smart metering event as:[943]

> an event which results in Ergon Energy being required to install smart meters for some or all of its customers or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation, and which:
>
> - is not included in another category of pass through event; and

[939] Energex, *Regulatory proposal*, July 2009, pp. 296–297.
[940] Energex, *Regulatory proposal*, July 2009, p. 297.
[941] Energex, *Regulatory proposal,* July 2009, p. 298; and appendix 20.3.
[942] Ergon Energy, *Regulatory proposal*, July 2009, p. 414.
[943] Ergon Energy, *Regulatory proposal*, July 2009, p. 414.

- materially increases the cost to Ergon Energy of providing Direct Control Services.

Transfer of regulatory functions to a national regulatory framework

Ergon Energy defined this event as:[944]

> the transfer of the current regulation of retail and distribution activities to a national framework …. where the event:
>
> - is not included in another category of pass through event; and
> - materially increases the cost to Ergon Energy of providing Direct Control Services.

Introduction of an emissions trading scheme

Ergon Energy defined this event as:[945]

> an event which results in the imposition of legal obligations on Ergon Energy arising from the introduction or operation of a carbon emissions trading scheme by the Federal or Queensland Governments during the course of the regulatory control period and which:
>
> - is not included in another category of pass through event; and
> - materially increases the cost to Ergon Energy of providing Direct Control Services.

Distribution losses

Ergon Energy defined this event as:[946]

> an event which results in it facing additional costs or legal obligations in relation to distribution losses from the operation of its distribution system. This includes a situation where financial responsibility for distribution losses is transferred to DNSPs or an emissions charge is imposed in relation to distribution losses as part of the Federal Government's greenhouse policy, which:
>
> - is not included in another category of pass through event; and
> - materially increases the cost to Ergon Energy of providing Direct Control Services.

Network obligation in relation to electric and magnetic fields

Ergon Energy sought AER approval that potential obligations imposed by an Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) draft standard would constitute a regulatory change event.[947]

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[944] Ergon Energy, *Regulatory proposal*, July 2009, p. 414.
[945] Ergon Energy, *Regulatory proposal*, July 2009, pp. 414–415.
[946] Ergon Energy, *Regulatory proposal*, July 2009, p. 415.
[947] Ergon Energy, *Regulatory proposal*, July 2009, p. 415.

Changes in reporting requirements

Ergon Energy sought AER approval that a change in reporting requirements from the AER or another government or regulatory body would constitute a regulatory change event.[948]

Changes in taxes or other levies

Ergon Energy sought AER approval that changes in taxes and levies which fall outside the scope of the tax change event in the NER will instead constitute a regulatory change event. Ergon Energy provided two examples of taxes that it proposed should fall under this category: the increase of the corporate income tax rate from the current 30 per cent to 40 per cent, and the release of an interpretive decision by the Australian Tax Office that a benchmark efficient entity (and therefore Ergon Energy) could not claim certain tax deductions which it currently does deduct.[949]

Proposed nominated events

Ergon Energy proposed that the following two events be nominated as pass through events:[950]

> **Force majeure**: Ergon Energy considers that a force majeure event relates to any fire, flood, earthquake, storm or other weather-related event or natural disaster, act of nature, riot, civil disorder or rebellion or other similar cause that occurs during a regulatory control period and:
>
> - is not included in another category of pass through event;
> - is beyond the reasonable control of Ergon Energy;
> - is not covered under Ergon Energy's self insurance allowance; and
> - materially increases the cost to Ergon Energy of providing its Direct Control Services.
>
> **Change of business structure event (that is externally imposed)**: Ergon Energy proposes that any change in the structure of its distribution business that is mandated by the Government should be classified as a pass through event where the event:
>
> - is not included in another category of pass through event; and
> - materially increases or decreases the cost of providing its Direct Control Services.

Alternative control services

Ergon Energy proposed that the pass through provisions for the defined events and nominated events should be applied to both standard control and alternative control services.[951]

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948 Ergon Energy, *Regulatory proposal*, July 2009, p. 415.
949 Ergon Energy, *Regulatory proposal*, July 2009, pp. 415–416.
950 Ergon Energy, *Regulatory proposal*, July 2009, p. 416.
951 Ergon Energy, *Regulatory proposal*, July 2009, p. 412.

15.4 Submissions

The Energy Users Association of Australia (EUAA) stated that the list of pass throughs proposed by Energex was unreasonable. It also considered that the pass throughs proposed by Ergon Energy were inconsistent with the NER, and none of the categories proposed should be allowed. The EUAA noted it does not support cost pass through as a matter of principle, and stated that it believed that information asymmetry meant that cost reductions would never be passed through in a regulatory control period.[952]

15.5 Issues and AER consideration

15.5.1 Criteria for assessing proposed pass through events

Provisions of the NEL and NER

The NER provides that the AER may nominate events in its determination that will constitute pass through events for the next regulatory control period.[953] Neither the NEL nor the NER provide any direct guidance to the AER on the matters it should take into account in deciding which events should be accepted as nominated pass through events. Guiding principles in the NEL and the general structure of the incentive regime, however, provide indirect guidance to the AER.

Ergon Energy referred to the revenue and pricing principles in section 7A(2) of the NEL which provides:[954]

> (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.

The requirement to provide a reasonable opportunity for DNSPs to recover at least the efficient costs of providing direct control network services and complying with regulatory obligations must be balanced against the need to provide effective incentives required under section 7A(3) in the NEL:

> (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

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952 EUAA, *Submission to the AER*, 28 August 2009, pp. 20–21, para 4.4(9) and para 4.5(9).
953 NER, chapter 10, definition of pass through event.
954 Ergon Energy, *Regulatory proposal*, July 2009, p. 412.

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

A pass through provides an opportunity to recover efficient costs that could not reasonably be provided for in the distribution determination. It is limited in its application as it has the potential to undermine the incentive to effectively manage risk in a least cost manner.[955]

The NER requires a distribution determination to specify allowances for a DNSP's total capex and opex programs for the next regulatory control period.[956] As such the AER does not approve allowances for individual projects or individual cost items; DNSPs have discretion to manage the total expenditure allowances as they see fit. If costs associated with a particular activity increase, a DNSP may spend more of its allowance on that activity than was contemplated at the time of its regulatory proposal. Similarly, a DNSP may spend less of its allowance on a particular activity if the costs associated with that activity turn out to be less than the forecast provided at the time of the regulatory proposal. This flexibility allows DNSPs to revise their expenditure priorities as circumstances change.

Where an unexpected cost arises during the regulatory control period a number of options may be available to the DNSP. These include:

- adjusting expenditure priorities to accommodate the unexpected cost by deferring other expenditure
- deferring expenditure associated with the unexpected cost until the next regulatory control period, at which time the costs will be assessed as part of the next distribution determination
- seeking to pass through the costs of the event to customers during the regulatory control period under the cost pass through provisions of the NER.

Only costs that cannot be accommodated by the DNSP during the regulatory control period without significantly impacting its financial position should be passed through to customers during a regulatory control period.[957] Therefore, costs should generally only be passed through once the first two options have been fully exhausted. The AER considers its approach adequately ensures that pass through costs would have to be materially higher than those allowed for in the regulatory determination. Furthermore, while noting the EUAA's in principle opposition to cost pass throughs, the AER considers that its approach to cost pass through achieves an appropriate balance between ensuring that DNSPs have the opportunity to recover efficient costs, while maintaining the incentive for efficient investment, efficient provision of services, and efficient use of the distribution system.

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[955] See for example, AEMC, *Rule determination, National Electricity Amendment (Economic regulation of transmission services) Rule 2006 No. 18*, 16 November 2006, pp. 104–106. While this rule determination was in respect of the regulation of transmission services, the principles discussed apply equally to the regulation distribution services.

[956] NER, clauses 6.12.1(3) and 6.12.1(4).

[957] NER, chapter 10, definition of positive change event.

Relevant factors for nominating events as pass through events

The AER's distribution determinations for the ACT and NSW DNSPs listed eight assessment criteria as factors to which the AER had regard in determining whether an event should be nominated as a pass through event:[958]

- the event is already captured by the defined event definitions
- the event is clearly identified
- the event is uncontrollable, that is, a prudent service provider through its actions could not have reasonably prevented or substantially mitigated the event
- despite the event being foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by the DNSP at the time of submitting its regulatory proposal
- the event is not already insured against (either external or self insured)
- 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 undermine the incentive arrangements within the regulatory regime.

In the distribution determinations for the NSW DNSPs, the AER considered an event to be foreseeable if it was expected to occur.[959] The AER has considered this further and is of the view that the general meaning of foreseeability may capture a broader range of events than those expected to occur, including events that are possible but not expected. The AER considers that only events that are highly likely to occur should be nominated as specific pass through events. Therefore, the AER has decided to amend this factor as follows:

- despite the event being highly likely to occur, the timing and/or cost impact of the event could not be reasonably forecast by the DNSP at the time of submitting its regulatory proposal.

Of these factors, the AER considers that the likelihood of the occurrence of an event and the DNSP's degree of control over the event are the most significant factors. If the cost impacts of an event that is highly likely to occur can be forecast on a reasonable basis and/or the event is within the control of the DNSP, a specific nominated pass through will generally not be appropriate and it will not be necessary to consider the other factors. Where these two factors are satisfied, the other factors may also be considered.

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[958] AER, *Final decision, ACT DNSP*, 28 April 2009, p. 127; and AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 277.

[959] AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 278.

Where possible, costs that a DNSP expects will be incurred during a regulatory control period should be included in its forecasts of capex and opex. Pass throughs should generally only be considered for cost impacts that were unexpected at the time of submitting the regulatory proposal, or could not be forecast reliably. The nature of unexpected costs, however, is that the circumstances in which they will arise will often be difficult to define in advance of their occurrence, and accordingly it will be difficult to specifically nominate an event to cover these costs. However, an unexpected event that materially impacts on a DNSP's ability to provide direct control services should not be precluded from pass through solely on the basis that it is not possible to specifically define the event in advance of its occurrence.

The AER therefore considers that nominated pass through events should be divided into two categories:

1. **specific nominated pass through events –** these are events that are highly likely to occur and can be clearly defined. An event is only a specific nominated pass through event if the AER nominates the event in this distribution determination.[960] The AER has considered the above eight criteria, with emphasis on likelihood and controllability, in deciding which events should be specific nominated pass through events.
2. **general nominated pass through event –** this will apply to unexpected events. This event is a set of broadly defined circumstances, the occurrence of which will constitute a general nominated pass through event. The AER will determine during the next regulatory control period whether an event constitutes a general nominated pass through event, should the event occur.

Specific nominated pass through events

A specific nominated event must be highly likely to occur in terms of its occurrence during the regulatory control period, despite the timing and/or cost impact being unpredictable at the time the DNSP lodges its regulatory proposal. In such circumstances, the AER considers it preferable that these costs be recovered when they are able to be forecast on a reasonable basis and when the timing of the event is known with certainty.

An example of such an event is the Carbon Pollution Reduction Scheme (CPRS) event. The Commonwealth Department of Climate Change has published a timetable indicating that a CPRS will commence by 2010.[961] Therefore, the event is considered by the AER to be highly likely to occur, although the potential costs of compliance for DNSPs will be uncertain until the details of the scheme have been finalised. Conversely, an event such as a natural disaster, while a possibility, is not highly likely to occur during the next regulatory control period.

General nominated pass through events

The AER recognises the possibility of events occurring during a regulatory control period that are uncontrollable, unexpected, and have a material impact on costs.

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960 NER, chapter 10, definition of pass through event.

961 Department of Climate Change, *Carbon Pollution Reduction Scheme, Timetable,* July 2009, at http://www.climatechange.gov.au/emissionstrading/timetable.html.

Examples of such an event include a major natural disaster such as an earthquake, and liability for claims relating to asbestos or electric and magnetic fields. In these situations, although the occurrence of the event may be a possibility, it is not expected to occur during the next regulatory control period.

If an unexpected and uncontrollable event would have a material impact on a DNSP's costs such that it would jeopardise the DNSP's ability to provide direct control services in accordance with the requirements of the NEL and the NER, it is appropriate that the costs should be passed through to consumers. Where an event is of such an unusual and unexpected nature, and the associated costs are likely to have such an impact on the returns of the business that services would be jeopardised, it may be appropriate that the costs associated with the event should be passed through to customers immediately rather than deferring expenditure until the next regulatory period and including the costs in the next regulatory proposal.

Unexpected events are not easily defined. Therefore, rather than attempting to specifically define all unexpected events that could possibly occur during a regulatory control period, the AER considers it is appropriate to define a general set of circumstances, the occurrence of which will constitute a general pass through event.

The AER considers that an event should be classified as a general pass through event in the following circumstances:

- an uncontrollable and unexpected event occurs during the next regulatory control period, the effect of which could not have been prevented or mitigated by prudent operational risk management
- the change in costs of providing distribution services as a result of the event is material
- the event does not fall within any of the following definitions:
  - 'regulatory change event' in the NER (read as if paragraph (a) of the definition were not a part of the definition)
  - 'service standard event' in the NER
  - 'tax change event' in the NER
  - 'terrorism event' in the NER
  - 'smart meter event' in this draft decision
  - 'CPRS event' in this draft decision
  - 'feed-in tariff event' in this draft decision.

In the distribution determinations for NSW DNSPs, the AER defined a general nominated pass through event to include an unforeseeable, rather than unexpected, event. The AER noted that it would consider an event unforeseeable for the purposes of the definition if, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely than not to occur during the next regulatory control period.[962] The AER has considered this further and considers that this definition may not represent the generally accepted meaning of unforeseeable. The AER considers that the term ‘unexpected’ is preferable, and has therefore amended the definition of a general pass through event to include reference to an event being ‘unexpected’ rather than ‘unforeseeable’.

If a general pass through event occurs, a DNSP may apply to the AER for a pass through of the costs associated with the event under clause 6.6.1 of the NER. The AER will determine upon application by the DNSP during the regulatory control period and once the particular circumstances of an event are known, whether a general nominated event has occurred.[963]

In assessing whether a pass through event has occurred (whether the event is a specific nominated event, a general nominated event, or an event defined in the NER), the AER will take into account the matters listed in clause 6.6.1(j) of the NER. These matters include the need to ensure the DNSP recovers only incremental costs, and the efficiency of the DNSP’s decisions and actions in relation to the risk of the event, including whether the DNSP has failed to take reasonable action to reduce the magnitude of the event. The AER will also consider the materiality of the costs proposed for pass through.

15.5.2 Materiality

In the absence of a significant materiality threshold, DNSPs may seek to pass through immaterial costs that could be accommodated by the DNSP in the normal course of its operational activities and budget management. To maintain the DNSPs’ incentives to manage expenditure efficiently, the AER considers that a significant materiality threshold should generally apply to pass through events.

Materiality threshold for general nominated events

In the distribution determinations for ACT and NSW DNSPs, the AER stated that it will generally consider that a pass through event will have a material impact if the costs associated with the event would exceed 1 per cent of the smoothed revenue allowance specified in the final decision in the years of the regulatory control period that the costs are incurred.[964]

Energex stated that it is unreasonable to apply a materiality threshold based solely on annual revenue, suggesting that is unfair to DNSPs that have high revenues due to the relative size of the business.[965] Energex instead proposed that the threshold for general nominated events should be the lower of 1 per cent of average annual revenue or $5 million.[966]

The AER does not agree that a 1 per cent of revenue threshold is unfair to DNSPs that have high revenues. A 1 per cent threshold will have proportionately the same impact

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962 AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 296.
963 NER, clause 6.6.1(d).
964 AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 280; and AER, *Final Decision, ACT DNSP*, 28 April 2009, p. 130.
965 Energex, *Regulatory proposal*, July 2009, p. 296.
966 Energex, *Regulatory proposal*, July 2009, p. 296.

on a DNSP with smaller revenues as a DNSP with higher revenues. That is, all else being equal, a business with larger annual revenue requirements will have a greater capacity to respond to an unexpected event without compromising service delivery. While Energex accepted this notion, it proposed that the 1 per cent threshold be capped at $5 million. However, no reasons were provided by Energex to explain why the scope for a DNSP to accommodate unexpected costs should be capped at a fixed amount.

Capping the threshold at a fixed amount would have the effect of requiring events to have proportionately different impacts on DNSPs according to their revenues. For a smaller DNSP with average revenues of less than $500 million, the lower of the two proposed thresholds would be 1 per cent of average annual revenue. However, for a business with average revenues higher than $500 million, the lower of the two thresholds would be $5 million, which would be less than 1 per cent of average annual revenue. The result is that a smaller DNSP would face a higher threshold in terms of the overall impact on its revenues, comparative to a larger DNSP.

The difference in sizes of the businesses of DNSPs across the NEM is the reason for selecting a threshold based on a percentage, rather than capping the threshold at a fixed amount. The AER does not accept that a percentage threshold should be capped by a fixed amount.

Energex also submitted that the materiality threshold should be applied to the total of the costs of the event rather than just to the costs that are incurred in a specific year. It noted that events may have cost impacts over a number of years and referred to a QCA decision which rejected cost pass through amounts in years that the costs incurred did not meet the annual materiality threshold.[967]

The AER does not agree that the threshold should be applied to the total of the costs of the event rather than the costs incurred in a specific year. A cost pass through is only appropriate where the DNSP cannot defer the pass through of costs until the next regulatory control period without significantly affecting its ability to provide distribution services. If the costs in a particular year associated with an unexpected event can be managed by the DNSP without significantly affecting its ability to provide distribution services in that year, then a cost pass through is not appropriate. That is, if the costs incurred in a specific year are below the materiality threshold, those costs will not have a significant impact on the DNSP such that its provision of distribution services is jeopardised and therefore do not qualify for pass through. Only in those years where the costs associated with an eligible pass through event are material does the AER consider that a pass through in those years should be accepted.

The AER has considered the submissions of Energex, but will adopt the same threshold for general nominated events as that adopted in the distribution determinations for ACT and NSW DNSPs, and will apply the threshold to the costs of the event incurred in a specific year. This threshold is 1 per cent of the smoothed revenue allowance specified in the AER’s final distribution determination for each of the years of the regulatory control period in which the costs are incurred. The AER notes that in order to qualify for a general nominated event the materiality threshold

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967 Energex, *Regulatory proposal*, July 2009, pp. 296–297.

must be satisfied for each year of the regulatory control period. The materiality threshold for a general nominated event will not be satisfied on the basis of the DNSP's total costs that it seeks to recover for the entire regulatory control period. Furthermore, for the avoidance of doubt, for capex incurred in relation to an eligible pass through event, the incurred costs are the return on and depreciation of capital until the end of the regulatory control period.

The AER considers that the costs of a pass through event must meet this materiality threshold in order to warrant immediate pass through to customers, rather than waiting for costs to be re–assessed at the following regulatory control period. Therefore, this materiality threshold must be satisfied in order for an event to constitute a general nominated pass through event.

Materiality threshold for specific nominated events

In some circumstances the AER may determine that a lower materiality threshold is appropriate. Costs associated with a specific nominated event are generally not included in the forecast costs at the time of the distribution determination because, at the time the regulatory proposals were submitted, the precise timing of the event and/or the cost impact of the event could not be forecast on a reasonable basis. In these circumstances, it is appropriate that a lower materiality threshold be adopted that represents the administrative costs of assessing such an application. The costs associated with these events would generally have been included, without regard to the materiality of the financial impact of the event on the DNSP, had the necessary information been available at the time of the final decision.

The costs of assessing a cost pass through may, in certain circumstances, be very low. As specific nominated pass through events are narrowly defined, the AER considers that a low materiality threshold will not undermine incentives to manage expenditure efficiently. Therefore the AER will apply a materiality threshold of the administrative costs of assessing an application relating to specific nominated events.

15.5.3 Proposed nominated pass through events that the AER accepts

Smart meter event

In July 2009 the MCE released a second exposure draft of amendments to the NEL to facilitate and support the accelerated roll out and trials of smart meters in participating jurisdictions.[968] It is therefore reasonable to suggest that a smart meter event is highly likely to occur in the next regulatory control period.

At this time, the exact form, timing and scope of a smart meter roll out or trial is unknown and so while the event is highly likely to occur, the timing and cost impact are not known. As a result, the costs associated with the event are very difficult to forecast and include in the building blocks. The event therefore satisfies the requirement of being highly likely to occur with uncertain cost impacts. The event is uncontrollable, because if the event occurs, the Qld DNSPs will be legally obliged to undertake trials and/or roll outs.

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968 MCE, Standing Committee of Officials, *National Electricity (South Australia) (Smart Meters) Amendment Bill 2009, Exposure Draft 3/7/2009*, available: www.mce.gov.au.

The MCE Standing Committee of Officials (MCE SCO) policy response on the *National Electricity Amendment* Bill for smart meters indicates that any mandated requirement to roll out smart meters is intended to be imposed so that it constitutes a 'regulatory obligation or requirement' and hence the definition of a regulatory change event will be satisfied.[969] Therefore, if the obligation has a material impact on a DNSP's costs and substantially affects the manner in which it provides direct control services, it is likely that it will constitute a regulatory change event. However, the AER would need to determine whether these requirements are satisfied when the impact on the DNSP is known.

The other criteria listed in section 15.5.1 of this decision support the nomination of a smart meter event. Therefore, the AER has nominated a smart meter event as a nominated pass through event.

Although Ergon Energy proposed that this event be treated as a regulatory change event, the AER is unable to state whether or not the event would satisfy the definition in the NER of a regulatory change event, and accordingly this specific nominated event will apply to both Energex and Ergon Energy.

The AER notes that clause 6.6.1(j)(2) requires the AER to determine a pass through amount and the amount that should be passed through to distribution network users in each regulatory year of the regulatory control period. In its determination of the pass through amount the AER must take into account the increase in costs in the provision of standard control services that the DNSP has incurred and is likely to incur until the end of the regulatory control period. In taking this into account, the AER will consider the net cost impact of a smart meter event, including any expected reductions in opex associated with the event.

Should detail of a smart meter roll out in Queensland become clearer prior to the AER's final determination, the AER will consider whether any costs associated with the roll out could be included as part of the determination rather than making provision for a nominated pass through event. The AER would have to be satisfied that any such costs were consistent with the requirements of the NER.

Carbon Pollution Reduction Scheme (CPRS) event

The Commonwealth Department of Climate Change has published a timetable indicating that a CPRS will commence by 2010.[970] It is therefore reasonable to suggest that a CPRS event is highly likely to occur in the next regulatory control period. At this time, the exact form, timing and scope of the CPRS is unknown and so while the event is highly likely to occur, the timing and cost impact of the event are uncertain. The event is uncontrollable, because if the event occurs, the Qld DNSPs will be legally obliged to take part in the scheme.

The AER is unable to state whether the event is likely or unlikely to fall within the definition of a regulatory change event because at the time of this draft decision it is

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969 MCE, *Standing Committee of Officials Policy Response, National Electricity Amendment Bill - Smart Meters*, June 2009, p. 8.

970 Department of Climate Change, *Carbon Pollution Reduction Scheme, Timetable*, 2 July 2009, accessible at http://www.climatechange.gov.au/emissionstrading/timetable.html.

unclear how a CPRS scheme will be implemented. Therefore, it is not clear whether or not such an obligation would be already captured by the defined event definitions. The AER would need to determine whether these requirements are satisfied when the impact on the DNSP is known.

The other criteria listed in section 15.5.1 support the nomination of a CPRS event. The AER has therefore nominated a CPRS event as a nominated pass through event.

In its regulatory proposal, Energex submitted that no materiality threshold should apply to a CPRS event.[971] Under clause 6.6.1 of the NER, the process by which an application is made for a cost pass through requires the occurrence of either a positive change event or a negative change event. As defined in chapter 10 of the NER, both a positive and negative change event require a material effect on the cost of providing direct control services. A materiality threshold is therefore a necessary element of all pass through events, and accordingly the AER does not accept Energex's submission that no materiality threshold should apply to this event. The materiality threshold that will apply to the CPRS event will be equal to the administrative costs of assessing the pass through application.

Feed–in tariff event

Energex proposed a nominated pass through event to cover payments it is required to make under the Queensland feed–in tariff scheme.

As of March 2008, the Queensland government has operated a feed-in tariff scheme under which DNSPs are obliged to make payments for electricity generated by solar power systems and fed into the grid.[972] The AER acknowledges that Qld DNSPs may have insufficient historical data to reliably forecast the payments that they will be required to make under the scheme during the next regulatory control period. Therefore, although the event itself is highly likely to occur, the cost impact is difficult to forecast. The AER considers it appropriate that Qld DNSPs be permitted to recover or return to users any discrepancy between forecast and actual direct tariff payments through a nominated pass through event during the next regulatory control period. The AER expects that in subsequent regulatory control periods, Qld DNSPs will have sufficient data to be able to develop reliable forecasts and a pass through may not be appropriate at that time.

The other factors listed in section 15.5.1 also support the nomination of a feed–in tariff event because:

- the event is not already captured by the defined event definitions
- the event does not undermine incentives for the Qld DNSPs to pursue productivity improvements, because they cannot influence the parameters which impact the direct payments under the feed–in tariff scheme, and they will only recover incremental amounts.

[971] Energex, *Regulatory proposal*, July 2009, p. 287.
[972] Energex, *Regulatory proposal*, July 2009, p. 284.

Energex proposed that the event should apply to total payments made to retailers, rather than Energex providing a forecast and the event applying to forecast errors. The AER notes that ActewAGL, which proposed a similar event to cover the ACT feed–in tariff scheme, was able to provide a forecast of payments, and a specific nominated pass through was allowed for forecast errors.[973] The AER considers that the Qld DNSPs should similarly include forecasts of total payments associated with the feed–in tariff as part of their proposed opex allowance, with forecast errors, rather than total payments, being subject to cost pass through.

Therefore, the AER has nominated a feed–in tariff event as a nominated pass through event. The AER substitutes the following definition for that proposed by Energex:

> A **feed–in tariff event** occurs if, at the end of a regulatory year of a regulatory control period, the amount of feed-in tariff payments made by a Qld DNSP for that regulatory year is higher or lower than the amount of feed-in tariff payments (if any) that is provided for in that Qld DNSP's annual revenue requirement for that regulatory year.
>
> Relevant feed–in tariff payments under this pass through mechanism are those paid through the operation of the *Electricity Act 1994 (Qld)*, and any amendments to this Act.

The AER notes that the feed-in tariff scheme also applies to Ergon Energy. Ergon Energy did not propose a cost pass through to deal with uncertainties surrounding the amount of feed-in tariff payments; rather, it proposed an annual revenue adjustment. As noted in section 4.3 of this draft decision, the AER has decided not to include an annual revenue adjustment for the feed-in tariff scheme. The AER considers that a specific nominated pass through event is an appropriate way to deal with uncertainties surrounding feed-in tariff payments, and accordingly this event will apply to both Energex and Ergon Energy.

15.5.4 Nominated pass through events that the AER does not accept

Specific events proposed by Energex

For each of the events proposed, Energex's definitions excluded circumstances where an event falls into another category of pass through event. For example, a Regulatory Information Order (RIO) reporting event was defined as a change in the AER's regulatory reporting requirements under a RIO *where the event does not fall within any other category of pass through event*.[974] As drafted, the event cannot constitute a regulatory change event because it falls within another category of pass through event (the proposed RIO reporting event). This is despite the event being a change in regulatory obligations and hence closely resembling the circumstances that a regulatory change event was intended to capture.[975].

The effect of this drafting is that the RIO reporting event proposed by Energex is not captured by the defined event conditions (despite the general circumstances described by the RIO reporting event being similar to the circumstances described by the

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[973] AER, *Final decision, ACT DNSP*, 28 April 2009, pp. 130–132.
[974] Energex, *Regulatory proposal*, July 2009, appendix 20.2, p. 2.
[975] NER, chapter 10, definition of regulatory change event.

definition of a regulatory change event). Whether or not an event is captured by the defined event conditions is one of the factors the AER will consider in deciding whether an event should be a specific nominated pass through event.

In considering this factor, it is relevant to consider whether the general circumstances described by a proposed event would be captured by a defined event. For example, with respect to a RIO reporting event, it is relevant to look beyond the drafting and to consider whether a change in regulatory reporting requirements under a RIO would be likely to constitute a regulatory change event (despite the drafting of the proposed event explicitly excluding these circumstances). If the general circumstances described by a RIO reporting event would be likely to satisfy the definition of a regulatory change event, it is not necessary to nominate a specific event as a regulatory change event.

In considering whether proposed events are already captured by defined event conditions, the AER has therefore considered Energex's proposed events as if they did not exclude events falling into other categories of pass through events.

Regulatory Information Order (RIO) reporting event/NECF event/OH&S event/GSL event

The AER considers that these types of events are the types of events that the NER defined 'regulatory change event' is designed to capture.

In order to constitute a regulatory change event, the event must substantially affect the manner in which a DNSP provides direct control services.[976] It is unclear at this time whether or not these events will have that effect, however to the extent that they do have that effect, there would be scope to consider whether they constitute regulatory change events. Therefore specific nominated events are not necessary.

Henry Review tax event

This event relates to the imposition of tax changes arising from the adoption by government of the recommendations of the Henry Review.[977] While the AER accepts that it is highly likely that the review will make recommendations, which may be implemented by government, it does not accept that it is highly likley that the review will result in legal changes that will have a material impact on Energex's costs. No indications have been made of what recommendations the review will make to government when the process is concluded. Therefore it is not highly likely that any specific changes to tax which affect Energex's costs will be adopted as a result of the Henry Review. For this reason, the AER considers that the event should not be nominated as a specific nominated pass through event.

Changes to tax obligations arising from the implementation of the Henry Review may fall into the defined events included in the NER, such as the tax change event or regulatory change event. Should such an event fall outside these categories and have a material impact on a DNSP's costs, the event may constitute a general pass through event. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

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976 NER, chapter 10, definition of regulatory change event, paragraph (c).

977 The Henry Review is a Commonwealth government directed review of the Australian tax system being undertaken by a review panel chaired by Dr Ken Henry, see www.taxreview.treasury.gov.au.

National Broadband Network event

Energex proposed an event relating to costs arising from the requirement to install or maintain a broadband network as part of Energex's distribution network. While it appears likely that the government may pass legislation to implement a national broadband network, it is not highly likely that this legislation will impose obligations on DNSPs. Decisions about the involvement of DNSPs have not yet been articulated and other options are under consideration for the implementation of elements of the national broadband network.[978] Therefore, the AER considers that this event should not be a specific nominated event, because it is not highly likely to occur.

Depending on the manner in which any obligations are imposed and the impact they will have on DNSPs, it is possible that this event may constitute a regulatory change event. However, if the event occurs in the next regulatory control period and does not satisfy the definition of a regulatory change event but has a material impact on a Qld DNSP's costs, then the event may constitute a general pass through event. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

Storm disaster event

Energex stated that it faces a foreseeable catastrophic storm risk and proposed that a specific event should be nominated for catastrophic storm damage, the costs of which exceed Energex's proposed self insurance allowance of $10 million.[979]

The AER acknowledges that storms are highly likely to occur in the area of Queensland that Energex operates. Energex indicated in its regulatory proposal that 29 severe weather events occurred in 2005–06.[980] In November 2008 severe storms in parts of Brisbane resulted in loss of life and extensive damage to property including that of Energex and would likely be described by many as catastrophic. However, the storms in both these years did not exceed the cost threshold of 1 per cent of actual annual regulated revenue (around $6 million) applied by the QCA for cost pass through applications.[981] Instead, the cost impact of these storms has been managed within existing opex and capex allowances.

The AER considers that a specific nominated event is not appropriate for a catastrophic storm event because such an event, as defined by Energex, is not highly likely based on the history of these events. Furthermore, the definition of such an event is unclear (as noted above) other than the numerical threshold proposed by Energex. Nevertheless, a catastrophic storm exceeding $10 million in costs, or any other storm for that matter, that causes damage to Energex's network may be eligible for pass through under the general nominated pass through event, subject to meeting the materiality threshold. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

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[978] Australian Government, *National broadband network: regulation reform for 21st century broadband, discussion paper*, April 2009.

[979] Energex, *Regulatory proposal*, July 2009, p. 293.

[980] Energex, *Regulatory proposal*, July 2009, p. 111.

[981] QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 50.

Events which Energex proposed as general nominated events

Energex proposed as general nominated events a number of events that the AER identified in its decision for NSW DNSPs as events that may constitute general nominated pass through events.[982] In relation to these events, the AER position remains the same: the event in question may be a general nominated pass through event, but this question would be decided by the AER upon application by a DNSP for a cost pass through, when the details of and costs associated with the event are known.

Energex also proposed two additional events as general nominated pass through events, interim change events and retailer credit risk events.

Interim change events

Energex submitted that the AER should consider that interim change events may constitute general nominated pass through events.[983] These events cover events that occur during the current regulatory control period but have a cost impact in the next regulatory control period.

The AER considers that these events cannot constitute general nominated pass through events because the definition of the general nominated pass through event specifies that the event must occur during the next regulatory control period.

The AER notes, however, that clause 11.16.9 of the NER appears to cover a similar circumstance to that contemplated by the proposed interim change event. The clause permits an application to be made to the AER by a Qld DNSP for a cost pass through in relation to an event which occurs before 1 July 2010 and which would constitute a pass through under the 2005 determination made by the QCA. Therefore, while an interim change event as proposed by Energex will not constitute a general nominated pass through event, a cost pass through may be available under clause 11.16.9 of the NER if the event would constitute a pass through under the 2005 QCA determination.

Retailer credit risk event

Energex proposed a self insurance allowance to cover retailer credit risk up to $5 million, and proposed that any costs over $5 million relating to a failure by a retailer to pass on DUOS charges recovered from customers to Energex should be treated as a general nominated event.

As discussed in chapter 8 of this draft decision, the AER does not accept a self insurance allowance for retailer credit risk. Therefore, the AER considers this event as if Energex had not proposed a minimum cost impact of $5 million for this event.

The AER notes that Energex has not provided any information on retailer default in Queensland and considers that a retailer credit risk event, while possible, is not highly likely to occur. The AER considers that should it occur a retailer credit risk event may constitute a general nominated pass through event. Whether or not an event of this sort falls into the category of the general nominated pass through event would be assessed at the time of an application for cost pass through being made to the AER.

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[982] Energex, *Regulatory proposal*, July 2009, p. 294.
[983] Energex, *Regulatory proposal*, July 2009, p. 295.

The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

Events proposed by Ergon Energy as regulatory change events

Ergon Energy listed a number of events it considered to be regulatory change events for which it sought confirmation from the AER that they would be treated as regulatory change events.[984]

While the AER may comment on whether a certain event is likely or unlikely to fall within one of the categories of pass through event defined in the NER, it cannot confirm that certain events will, if they occur, be considered regulatory change events, as part of its distribution determination. This is because it is not possible to conclude that the definition of a regulatory change event is satisfied before the details and impact of the event are known. The AER will consider whether an event falls within a certain category when an application for cost pass through is made, at which time the details of the event will be known.

The AER has also considered whether the events for which Ergon Energy sought this approval should instead be nominated as specific pass through events.

Change to minimalist transitioning approach event

Ergon Energy sought AER approval that a change to the minimalist transitioning approach that set less onerous time limits for gathering NMI information would constitute a regulatory change event. The Queensland Electricity Industry Code (EIC) requires that the QCA assess each year whether the provisions of the minimalist transitioning approach should be retained. On 13 June 2009, the QCA decided to retain the provisions. With respect to both the QCA decision and Ergon Energy's regulatory proposal, no information suggests that the QCA would adopt a different position in the future even though a change to the approach is possible[985]. The AER considers that to the extent that this event would substantially affect the manner in which a DNSP provides direct control services, it is likely to constitute a regulatory change event.[986]

Given that this event may constitute a regulatory change event, the AER considers that this event should not be nominated as a specific nominated event.

Transfer of regulatory functions to a national regulatory framework event / changes in reporting requirements event

Ergon Energy sought AER approval that the transfer of retail and distribution activities to a national framework, and/or any change to regulatory reporting requirements would constitute regulatory change events. The AER considers that to the extent that these events would substantially affect the manner in which a DNSP

[984] Ergon Energy, *Regulatory proposal*, July 2009, p. 415.

[985] QCA, Letter to Ergon Energy, 23 June 2009, <http://www.qca.org.au/files/E-MinsTransApp-QCA-LTRErgon09Rev-0609.pdf>.

[986] NER, chapter, definition of regulatory change event: 'a change in regulatory obligation or requirement that …(d) materially increases or materially decreases the costs of providing those services.'.

provides direct control services, it is likely that they would constitute regulatory change events.[987]

Therefore the AER considers that these events should not be nominated as specific pass through events.

Distribution loss event

Ergon Energy sought AER approval that additional costs or legal obligations in relation to distribution losses would constitute a regulatory change event.

The AER is unable to state whether such an event is likely or unlikely to satisfy the definition of a regulatory change event because the definition provided by Ergon Energy provides insufficient information about the form that additional costs or legal obligations in relation to distribution losses may take.

The AER considers that the distribution loss event should not be nominated as a specific pass through event. While a distribution loss event may occur in the next regulatory control period, there is no evidence to suggest that it is highly likely to occur. However, if the event occurs in the next regulatory control period and has a material impact on a Qld DNSP's costs, then the event may constitute a general pass through event. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

Network obligations in relation to electric and magnetic fields event

Ergon Energy sought AER approval that the imposition of an ARPANSA Draft Standard would constitute a regulatory change event.

This event does not appear highly likely to occur in the next regulatory control period. Ergon Energy has not provided any indications that the ARPANSA standard is highly likely to be imposed on DNSPs in the next regulatory control period.

To the extent that this event would substantially affect the manner in which a DNSP provides direct control services, it is likely to constitute a regulatory change event. Given that this event is not highly likely to occur and may constitute a regulatory change event, the AER considers that this event should not be nominated as a specific nominated event.

Changes in taxes and other levies event

Ergon Energy sought AER approval that certain tax changes falling outside the scope of the tax change event will constitute a regulatory change event. The AER agrees that the definition of 'regulatory obligation or requirement' in the NEL captures some taxes or other levies payable by a DNSP. However, whether the definition is satisfied will depend, among other things, on the exact nature of the tax change. In order to constitute a regulatory change event, the event must also substantially affect the manner in which a DNSP provides direct control services. To the extent that this

[987] NER, chapter, definition of regulatory change event: 'a change in regulatory obligation or requirement that: ...(d) materially increases or materially decreases the costs of providing those services.'.

event is likely to have this effect, this event may constitute a regulatory change event.[988]

The AER considers that this event should not be nominated as a specific pass through event because there is no evidence that the event is highly likely to occur and, additionally, it may also constitute a regulatory change event.

Specific events proposed by Ergon Energy

Force majeure event

The AER considers that the force majeure event that will have a material impact on Ergon Energy is not highly likely to occur and should not be nominated as a specific event.[989] While it is possible that a force majeure event will occur in the next regulatory control period, Ergon Energy has not provided any information to suggest that the event is highly likely to occur. To the extent that this event would substantially affect the manner in which a DNSP provides direct control services, it is also likely to constitute a general nominated pass through event. For this reason, the AER decides that the event should not be nominated as a specific pass through event. Should the event occur in the next regulatory control period and have a material impact on Ergon Energy's costs, the event is likely to constitute a general pass through event. The AER would assess any application for cost pass through with reference to this decision and the requirements of the NER.

Change of business structure (that is externally imposed)

The AER does not accept that any changes in the structure of Ergon Energy's distribution business that are mandated by government should be nominated as a pass through event. Ergon Energy has not provided any information to indicate that such an event is highly likely to occur. Should the event occur in the next regulatory control period and have a material impact on a DNSP's costs, the event may constitute a general pass through event. The AER would assess any application for cost pass through with reference to this decision and the requirements of the NER.

15.6 Other matters

15.6.1 Pass through clause

The AER notes that clause S6.1.3(2) of the NER requires a DNSP to provide the following information in its building block proposal:

> A proposed pass through clause with a proposal as to the events that should be defined as pass through events.

The AER considers that the detail of the pass through proposals in a DNSP's regulatory proposal will generally be sufficient to meet the requirements of clause S6.1.3(2).

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[988] NER, chapter, definition of regulatory change event: 'a change in regulatory obligation or requirement that …(d) materially increases or materially decreases the costs of providing those services'.

[989] AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 287.

However, Energex has included a specific pass through clause in its regulatory proposal.[990] The AER notes Energex's pass through clause reflects the relevant pass through provisions of the NER, and incorporates other elements of Energex's regulatory proposal, such as the definition of materiality.

The AER considers that where any inconsistencies between the NER and Energex's pass through clause arise, the NER prevails. Similarly, where any inconsistencies between the AER's distribution determination and Energex's pass through clause arise, the AER's distribution determination prevails.

15.6.2 Application to alternative control services

The AER considers that it is appropriate to apply the pass through provisions of the NER to alternative control services, as all direct control services are subject to the distribution determination. Therefore, the events that are nominated in this determination will apply to all direct control services.

15.7 AER conclusion

15.7.1 Specific nominated pass through events

The AER accepts the following pass through events as nominated pass through events for Ergon Energy and Energex:

> A **smart meter event** is an event which results in an obligation being externally imposed on a DNSP to install smart meters for some or all of its customers, or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of a statutory obligation or not, and which:
>
> (a) does not fall within the following:
>
> (1) the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)
>
> (2) any other category of pass through event
>
> (b) materially increases the cost of the DNSP providing direct control services.
>
> A **CPRS event** is an event which results in the imposition of legal obligations on a DNSP arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or Queensland government during the course of the next regulatory control period and which:
>
> (a) does not fall within the following:
>
> i) the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)
>
> ii) any other category of pass through event

[990] Energex, *Regulatory proposal*, July 2009, appendix 20.3.

(b) materially increases the cost of the DNSP providing direct control services.

Feed-in tariff event means a change in the total amount of direct feed-in tariff payments paid by a Qld DNSP in respect of the Qld feed-in tariff scheme. For the purposes of this definition, the change in the amount of the direct tariff payments paid by the DNSP must be calculated as the difference between:

(a) the amount of direct tariff payments paid by the DNSP in each regulatory year of the next regulatory control period, derived from the metered output of generators subject to the scheme and the applicable feed in tariff rate applying to the metered output; and
(b) the amount of scheme direct tariff payments which were forecast for the purpose of and included in the Qld distribution determination for each regulatory year of the regulatory control period

Relevant direct tariff payments under this pass through mechanism are those paid through the operation of the *Electricity Act 1994 (Qld)*, and any amendments to this act.

15.7.2 General nominated pass through event

The AER nominates the following general pass through event for Energex and Ergon Energy:

A general nominated pass through event occurs in the following circumstances:

1: An uncontrollable and unexpected event occurs during the next regulatory control period, the effect of which could not have been prevented or mitigated by prudent operation risk management.

2: The change in costs of providing distribution services as a result of the event is material.

3: The event does not fall into any of the following definitions:

‘regulatory change event’ in the NER (read as if paragraph (a) of the definition was not part of the definition)

‘service standard event’ in the NER

‘tax change event’ in the NER

‘terrorism event’ in the NER

‘smart meter event’ in this draft decision

‘CPRS event’ in this draft decision

‘feed-in tariff event’ in this draft decision.

For the purposes of this definition,

‘material’ means the costs associated with the event would exceed 1 per cent of the smoothed revenue allowance specified in the final decision in each of the years of the regulatory control period that the costs are incurred.

For the reasons set out above, the AER considers that the other events proposed by the Qld DNSPs should not be nominated as specific nominated pass through events. However, the AER notes that a Qld DNSP may apply to the AER during the next regulatory control period for a pass through where a general nominated pass through event occurs. The AER will determine throughout the next regulatory control period, upon application by a DNSP, whether such event has occurred.

In assessing a Qld DNSP's application for a cost pass through (whether in relation to a specific nominated event, a general nominated event or an event defined in the NER), the AER will take into account all of the matters listed in clause 6.6.1(j)(1)–(8) of the NER. These matters include the need to ensure that a Qld DNSP recovers only incremental costs, and the efficiency of a Qld DNSP's decisions and actions in relation to the event, including whether the Qld DNSP has failed to take action to reduce the magnitude of the event.

15.8 AER draft decision

In accordance with clause 6.12.1(14) of the NER, the additional pass through events that apply to the Qld DNSPs for the next regulatory control period are the:

- smart meter event
- CPRS event
- feed-in tariff event
- general nominated pass through event

as defined in section 15.7 of this draft decision.

16 Building block revenue requirements

16.1 Introduction

This chapter sets out the AER's calculation of annual revenue requirements for the Qld DNSPs, for the provision of standard control services for each year of the next regulatory control period. This chapter also sets out X factor values to be applied as part of the revenue caps to apply to the standard control services provided by the Qld DNSPs.

16.2 Regulatory requirements

Clause 6.3.2(a) of the 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;

(3) how any applicable efficiency benefit sharing scheme, service target performance incentive scheme or demand management incentive scheme 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 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 for the entire regulatory control period. The X factor must also minimise difference 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 NER. The building block proposal must also comply with the requirements of any relevant regulatory information instrument, such as a regulatory information notice (RIN) or regulatory information order (RIO).[991]

Under clause 6.12.3(d) of the NER, the AER must approve annual revenue requirements if it is satisfied that they have been calculated using the PTRM on the basis of amounts proposed by the DNSP and accepted by the AER, or otherwise determined by the AER under part C of the NER.

[991] NER, clause 6.3.1.

16.2.1 Annual building block revenue requirement

Clause 6.4.3(a) of the NER sets out the following building blocks that form the annual revenue requirement:

- indexation of the RAB
- return on capital
- depreciation
- forecast operating expenditure (opex)
- estimated cost of corporate income tax
- revenue increments or decrements arising from the application of any efficiency benefit sharing scheme, service target performance incentive scheme and demand management incentive scheme
- other revenue increments or decrements (if any) arising from the application of a control mechanism in the previous regulatory control period that are to be carried forward and are apportioned to the relevant year under the distribution determination for the current regulatory control period.

16.2.2 Post–tax revenue model

On 26 June 2008, in accordance with clause 6.4.1(c) of the NER, the AER published a PTRM[992] and associated handbook[993]. The PTRM sets out how the annual revenue requirement is to be calculated and includes:

- 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 estimate of corporate income tax is to be calculated.

16.3 Queensland DNSP regulatory proposals

16.3.1 Energex

Energex's calculation of annual revenue requirements and X factors is contained in its PTRM, and are summarised in table 16.1.

Energex has chosen to use the transitional provisions of the NER for Queensland to include capital contributions in its RAB.[994] Energex receives capital contributions (in

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[992] AER, *Final Decision, Electricity DNSPs PTRM*, June 2008.

[993] AER, *Electricity distribution network service providers: Post–tax revenue model handbook,* June 2008.

cash or kind) from customers. If these capital contributions are included in the RAB, Energex will also receive a return of, and on, these amounts. To prevent Energex being doubly rewarded, a revenue adjustment was required in its PTRM to reflect the capital contributions it is forecast to receive over the next regulatory control period.[995] Such a revenue adjustment for capital contributions has been made by Energex, as shown in table 16.1.

Table 16.1: Energex proposed annual revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation		87.1	96.4	108.0	119.6	120.6
Return on capital		748.5	863.5	983.8	1109.4	1234.7
Operating expenditure [a]		364.8	379.8	400.2	420.0	424.9
Tax allowance		83.05	92.10	101.95	112.44	120.76
Capital contributions		–64.6	–68.9	–70.9	–73.6	–75.7
Capital contributions under recovery 2008–09		1.2				
DUOS over recovery 2008–09		–48.6				
Tax over recovery 2008–09		–26.9				
Revenue from shared assets		–4.5	–5.3	–6.0	–6.5	–6.0
Annual revenue requirements		1140.1	1357.5	1517.1	1681.3	1819.3
Expected revenues	936.7	1202.7	1336.2	1484.5	1649.2	1831.5
Forecast CPI (%)		2.45	2.45	2.45	2.45	2.45
X factors [b] (%)		–25.34	–8.44	–8.44	–8.44	–8.40

Source: Energex, PTRM.
(a) Includes demand management innovation allowance, self insurance, and equity and debt raising costs.
(b) Negative values for X indicate real revenue increases under the CPI–X formula.

Energex has also chosen to use the transitional provisions of the NER for Queensland to include the proportion of shared assets used in the provision of alternative control services in its RAB for standard control services.[996] Therefore Energex will receive a return of, and on, the total value of these shared assets. However, Energex also receives payments from customers separately for alternative control services. To prevent Energex being doubly compensated, a revenue adjustment was required to reflect the use of shared assets for alternative control services over the next regulatory

[994] NER, clause 11.16.3.
[995] The alternative approach is to exclude capital contributions from the RAB.
[996] NER, clause 11.16.3.

control period.[997] An adjustment for revenue from shared assets has been made by Energex, as shown in table 16.1.

Energex proposed an X factor of –25.34 per cent (that is, a real increase) for the first year of the next regulatory control period to account for the increase in revenue requirements between 2009–10 and 2010–11. It proposed an X factor of –8.44 per cent for years 2011–12 to 2013–14 and an X factor of –8.40 per cent for the year 2014–15. These values result in the net present values (NPVs) of the annual revenue requirements and expected revenues[998] being equal over the next regulatory control period as shown in table 16.2.

Table 16.2: Energex proposed annual revenue requirements and expected revenue ($m, nominal)

	NPV	2010–11	2011–12	2012–13	2013–14	2014-15
Annual revenue requirements	5655.7	1140.1	1357.5	1517.1	1681.3	1819.3
Expected revenues	5655.7	1202.7	1336.2	1484.5	1649.2	1831.5
Difference (%)		5.5	–1.6	–2.1	–1.9	0.7

Source: Energex, PTRM.

16.3.2 Ergon Energy

Ergon Energy’s calculation of annual revenue requirements and X factors is contained in its PTRM submitted as part of its regulatory proposal, and are summarised in table 16.3.

Ergon Energy has used the transitional provisions of the NER for Queensland to include capital contributions and shared assets (used in the provision of unregulated and alternative control services) in its RAB. Accordingly, for the reasons discussed above with regard to Energex, revenue adjustments were required in relation to these amounts. These adjustments have been made by Ergon Energy, as shown in table 16.3.

997 The alternative approach is to exclude the portion of shared assets used for alternative control services from the RAB.

998 Expected revenues for the next regulatory control period are calculated by the PTRM and are a function of the expected revenues in 2009–10 (as determined by the Qld DNSPs) and the X factors required to achieve NPV neutrality between the expected revenues and the annual revenue requirements. The annual revenue requirements are determined by the building blocks assessment.

Table 16.3: Ergon Energy proposed annual revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation		103.4	116.8	113.7	130.5	134.3
Return on capital		664.1	763.0	874.9	987.74	1107.5
Operating expenditure [a]		391.3	417.6	438.2	451.1	446.7
Tax allowance		0.0	17.3	61.8	75.7	80.4
Capital contributions		–112.0	–121.2	–107.9	–117.5	–135.2
Revenue from shared assets		–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation		11.3				
Annual revenue requirements		1054.9	1190.1	1377.3	1524.0	1630.2
Expected revenues	845.2	1100.2	1213.9	1339.3	1477.6	1630.2
Forecast CPI (%)		2.45	2.45	2.45	2.45	2.45
X factors [b] (%)		–27.05	–7.69	–7.69	–7.69	–7.69

Source: Ergon Energy, PTRM
(a) Includes demand management innovation allowance, self insurance, and equity and debt raising costs.
(b) Negative values for X indicate real revenue increases under the CPI–X formula.

Ergon Energy proposed an X factor of –27.05 per cent (that is, a real increase) for the first year of the next regulatory control period to account for the increase in revenue requirements between 2009–10 and 2010–11. It proposed an X factor of –7.69 per cent for years 2011–12 to 2014–15. These values result in the NPVs of the annual revenue requirements and expected revenues being equal over the next regulatory control period as shown in table 16.4.

Table 16.4: Ergon Energy proposed annual revenue requirements and expected revenue ($m, nominal)

	NPV	2010–11	2011–12	2012–13	2013–14	2014–15
Annual revenue requirements	5102.2	1054.9	1190.1	1377.3	1524.0	1630.2
Expected revenues	5102.2	1100.2	1213.9	1339.3	1477.6	1630.2
Difference (%)		4.3	2.0	–2.8	–3.0	0.0

Source: Ergon Energy, PTRM.

16.4 Submissions

Submissions by the Energy Users Association of Australia (EUAA) and the Queensland Council of Social Service (QCOSS) expressed concern about the significant increases in prices resulting from the Qld DNSPs' regulatory proposals.[999] Their concerns included the detrimental social impacts on the elderly and low income families and the negative economic impacts on business activity.[1000] The QCOSS stated that 'tariffs should be designed so as to reflect the cost of efficient and reliable provision, while ensuring that electricity supply remains affordable for domestic (particularly disadvantaged domestic) customers'.[1001]

The EUAA argued that, while the Qld DNSPs' proposals gave some indicative pricing impacts for end users, these figures were very difficult to interpret. The EUAA suggested that the AER develop a standard template for providing such data.[1002] The EUAA considered this pricing information particularly important for the first year of the next regulatory period when the largest tariff increases are proposed by the Qld DNSPs.

The EUAA welcomed comments by the Qld DNSPs at the public forum that they would be willing to work with customers and the EUAA to better inform them about the tariff impacts of their proposals. While the EUAA considered the approach useful and constructive, it also considered that the AER has a broader regulatory responsibility to ensure that customers are more engaged in the regulatory process, have information about regulatory proposals and their tariff impacts and obtain more notice of tariff changes. The EUAA stated that 'the current situation, where the participation of and information available to customers is very limited, is a cause for significant concern'.[1003]

The EUAA also raised a concern over the 'glaring difference' with the relatively lower increase in the first year for ETSA Utilities compared with the heavy front-loading of tariff increases in Queensland. The EUAA recommended that the relative size of adjustments in the first year of a regulatory control period and the X factors in remaining years of the regulatory control period needs to be investigated further.[1004]

Origin observed that Energex's forecasts for consumption volumes in both 2006–07 and 2007–08 were higher than actual energy delivered and has generated revenues in excess of its allowed revenue requirement. Origin argued that this outcome suggests that its pricing levels have been set too high and recommended that careful scrutiny should be applied to the proposed pricing.[1005]

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999 EUAA, *Submission to the AER*, 28 August 2009; and QCOSS, *Response to Queensland DNSPs*, August 2009.
1000 QCOSS, *Response to Queensland DNSPs,* August 2009, p. 2.
1001 QCOSS, *Response to Queensland DNSPs,* August 2009, p. 3.
1002 EUAA, *Submission to the AER*, 28 August 2009, p. 11.
1003 EUAA, *Submission to the AER*, 28 August 2009, p. 12.
1004 EUAA, *Submission to the AER*, 28 August 2009, p. 12.
1005 Origin, *Queensland DNSPs*, August 2009, p. 7.

SPA Consulting Engineers (SPA) claimed that the value of gifted assets reported by Ergon Energy was less than the actual amount of the gifted assets received by Ergon Energy.[1006] SPA noted that for 2007–08 and 2008–09 Ergon Energy said it had received gifted assets of $0.5 million and $11.2 million respectively. However, for both years SPA stated it carried out the design and construction of assets which were gifted to Ergon Energy that exceeded the amount detailed by Ergon Energy. SPA noted that across all participants the amount of gifted assets would greatly exceed the amount detailed by Ergon Energy. SPA requested that the AER investigate the reporting of gifted assets so that an accurate value can be included into the regulatory arrangements for the next regulatory control period.

16.5 Issues and AER considerations

This section begins with a summary of the AER's consideration of issues that are common to the Qld DNSPs' proposals, then addresses each of the building blocks proposed by the Qld DNSPs. Further details on the AER's consideration of the Qld DNSPs' proposed opex, corporate income tax and depreciation are contained in chapters 8, 9 and 10 of this decision. The return on capital (using the weighted average cost of capital (WACC) determined in chapter 11) is also outlined.

16.5.1 Common issues

Proposed price increases and X factors

The X factors proposed by the Qld DNSPs reflect the real revenue changes for each year of the next regulatory control period. Table 16.5 lists the real percentage increases in an end user's annual electricity bill as a result of the Qld DNSPs' proposed X factors, in the first year of the next regulatory control period and the average for the subsequent four years.

Table 16.5: Qld DNSPs proposals – real increases in annual electricity bill (percentage)

	2010–11	Average 2011–12 to 2014–15
Energex	8.3	1.8
Ergon Energy	9.3	1.8

Note: Calculation assumes distribution network charges make up 40 per cent of an end user's bill and demand growth of 3.8 per cent per annum for Energex and 3 per cent per annum for Ergon Energy for the next regulatory control period.

The AER must set X factors subject to the requirements of clause 6.5.9 of the NER. In particular, the X factors must:

- have regard to each DNSPs' total revenue requirement for the next regulatory control period

[1006] SPA, *Submission to the AER*, August 2009, p. 5.

- minimise, as far as possible, the difference between the annual revenue requirement and expected revenue in the final year of the regulatory control period

- equalise, in NPV terms, the total revenue requirement and expected revenues over the next regulatory control period under the applicable form of control.

Clause 6.5.9(c) of the NER also provides for different X factors to be set for each regulatory year.

Within the bounds of these requirements, the AER considers there is some scope for the DNSPs and the AER to explore the possibility of reducing the impact of price shocks in the first year of the next regulatory control period.

The AER's draft decisions on the Qld DNSPs' X factors and the resulting effect on end users' annual electricity bills are presented in section 16.6.

Information on proposed changes to tariffs

The EUAA raised concerns regarding the detail of pricing information contained in the Qld DNSPs' regulatory proposals. The AER notes that the Qld DNSPs have provided some pricing information as part of their pricing proposals, although this information is necessarily at an aggregate level given the nature of the AER's building block assessment. In this chapter, the AER has presented an assessment of the likely effect of the overall expected change in distribution prices on the retail prices customers' face. This analysis is presented in section 16.6.

How the overall prices changes are then converted to specific tariffs and tariff components is a matter the Qld DNSPs must address as part of their pricing proposals that must be submitted each year. The AER is endeavouring to enhance customers' ability to be involved in this process. In particular, the AER has requested that the Qld DNSPs provide an indicative outline of their pricing structures for the coming year well in advance of the deadlines in the NER, which the AER considers are particularly tight for assessing prices.[1007]

The EUAA also noted concern about the differences in the relative size of the P_0 adjustments (that is, the X factor for the first year of the next regulatory control period) between the Qld DNSPs and ETSA Utilities. The AER notes it has no power to direct the DNSPs to adopt a particular profile of prices for a regulatory control period. Under clause 6.5.9(b)(2) of the NER the X factors must be set to minimise as far as possible the difference in the expected revenues for the last year of the regulatory control period in question and the annual revenue requirement for that last year. This required outcome is factored in to the calculation of the X factors contained in the PTRM. In addition, the AER can make decisions on the timing of certain capital and operating expenditures, which can alter the profile of prices that customers ultimately face over the course of the regulatory control period.

[1007] NER, clause 6.18.2(a).

Accuracy of existing prices and forecast sales quantity inputs

The control mechanism for the Qld DNSPs is a revenue cap. For a revenue cap, the PTRM does not require existing prices or forecast demand or customer numbers to determine the X factors.

Origin raised concerns that Energex over recovered its DUOS in previous years and noted the effect this had on prices. The AER notes that (as discussed in chapter 4) Energex will be required to operate a DUOS unders/overs account to ensure that a over recovery in one year, for example, is matched by a reduction in revenues in following year, so customers are no better or worse off over time. The AER will also review the Qld DNSPs pricing proposals to ensure these comply with the requirements of the NER. For example, under a revenue cap it is important that the forecast quantities used to convert the Maximum Allowable Revenue (MAR) each year to prices are reasonable, as required by clause 6.18.8(a)(2) of the NER. If the forecasts are not reasonable, prices will be too high or low relative to the level required for a DNSP to recover its MAR.

Forecast inflation

The AER considers that the forecast inflation rate for the next regulatory control period should be consistent with that used to determine the nominal WACC. For the purposes of this draft decision, the AER has used a forecast inflation rate of 2.45 per cent. The Qld DNSPs have also both used this inflation rate in their PTRMs.

16.5.2 Energex

Asset base roll forward and indexation

As discussed in chapter 5, the AER has determined the opening value of Energex's RAB as at 1 July 2010 to be $7887.4 million. The AER has rolled forward Energex's RAB in the next regulatory control period using the PTRM, as shown in table 16.6.

Table 16.6: AER forecast roll forward of Energex's regulatory asset base ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Opening RAB	7887.4	8956.5	10 090.9	11 260.2	12 440.6
Net capex [a]	1156.3	1231.6	1278.3	1301.0	1386.4
Indexation of the opening RAB	193.2	219.4	247.2	275.9	304.8
Straight–line depreciation	280.4	316.7	356.2	396.5	426.5
Closing RAB	8956.5	10 090.9	11 260.2	12 440.6	13 705.3

Note: The straight–line depreciation less the indexation of 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. Net capex also includes capitalised equity raising costs.

Depreciation

As discussed in chapter 10, the AER has not approved Energex's proposed depreciation allowance.

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 regulatory control period and to determine the depreciation allowance. Table 16.11 shows the resulting figures.

Return on capital

The AER considers that Energex's proposed return on capital has been calculated in accordance with the PTRM. However, the amount is affected by the AER's conclusions regarding other inputs to the PTRM, such as the opening RAB (chapter 5), the forecast capex allowance (chapter 7), and the WACC parameters (chapter 11).

The AER has determined the annual return on capital allowance by applying the WACC to Energex's opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.10 below.

The nominal vanilla WACC of 10.06 per cent is based on a post–tax nominal return on equity of 10.64 per cent and a pre–tax nominal return on debt of 9.68 per cent. These figures are calculated using observed market data as at 13 October 2009, and will be updated closer to the AER's final decision using the averaging period nominated by Energex.

Operating expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Energex of $1707.6 million (nominal) over the next regulatory control period. Table 16.10 shows the annual opex allowance, which equals an average amount of $341.5 million per annum in nominal terms.

Estimated taxes payable

Using the PTRM, the AER has modelled Energex's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this draft decision. Consistent with clause 6.5.3 of the NER, the amount of tax payable is estimated using:

- a 60 per cent gearing, based on the gearing of a benchmark efficient entity, rather than Energex's actual gearing
- a statutory company income tax rate of 30 per cent as determined by the AER, and
- a value of imputation credits (gamma) of 0.65.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 25.96 per cent for this draft decision. Table 16.7 shows the AER's estimate of Energex's tax payments.

Table 16.7: AER modelling of Energex's net tax allowance ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Tax payable	91.9	101.5	111.9	122.7	131.2
Value of imputation credits	59.8	66.0	72.7	79.8	85.3
Net tax allowance	32.2	35.5	39.2	43.0	45.9

Capital contributions

Under clause 11.16.3(b) of the NER, Energex continued with the QCA approach to the treatment of capital contributions and included forecast capital contributions in its RAB for the next regulatory control period. To prevent customers paying twice for contributed assets, Energex has included in its PTRM a forecast revenue adjustment for capital contributions in the next regulatory control period.

To determine the forecast capital contributions, Energex forecast both in-kind and cash contributions for the next regulatory control period. The methodology used by Energex for forecasting each type of contribution was based on:[1008]

- in-kind contributions – the anticipated growth in subdivision lots (based on historical trends) and increased contribution rates following an update to the capital contributions policy

- cash contributions – the historical trends, adjusted for any known material changes.

The AER considers that use of historical trend analysis is an appropriate approach to forecasting capital contributions and accepts the forecast capital contributions proposed by Energex as being consistent with clause 6.21.2(3) of the NER.

As discussed in chapter 4, the AER has rejected Energex's proposal for a capital contribution bank. Instead, the AER will require Energex to continue with the QCA approach of an annual adjustment for any under/over recovery of capital contributions against forecast being made to Energex's MAR each year. This annual adjustment should not form part of the PTRM and is discussed further in a subsection below.

Revenue adjustment for shared assets

Energex has included a revenue adjustment for expected use of shared assets for alternative control services during the next regulatory control period in its PTRM, as discussed in chapter 4. The AER reviewed Energex's assessment of the expected use

[1008] Energex, *Regulatory proposal*, July 2009, p. 270.

of these shared assets for alternative control services.[1009] While Energex identified an error related to street lighting services use of shared assets that it has undertaken to correct in its revised regulatory proposal,[1010] this error is immaterial and the AER therefore considers the revenue adjustment proposed by Energex for use of shared assets for alternative control services to be reasonable for the purposes of this draft decision.

As discussed in chapter 4, no annual adjustment will be made to Energex's MAR for any difference between expected and actual use of shared assets for alternative control services. This position contrasts with that for Ergon Energy, discussed below.

Revenue decrements arising from previous periods control mechanisms

Energex included in its PTRM adjustments associated with 2008–09 for under recovery of capital contributions, over recovery of DUOS and over recovery of tax. The net effect of these adjustments was a reduction of $74.3 million in its proposed revenue requirement for 2010–11 in its PTRM.

The AER does not consider that these adjustments should be included in the PTRM, because by doing so these adjustments affect the size of the X factors and thereby spread the impact of these adjustments over the next regulatory control period. The AER considers that these adjustments relate to the MAR for 2010–11 and should be reflected in the prices for that year. Accordingly, these adjustments have been removed from the PTRM for that year and instead be included as part of Energex's MAR for 2010–11. The calculation of the MAR for each year is detailed in chapter 4.

16.5.3 Ergon Energy

Asset base roll forward and indexation

As discussed in chapter 5, the AER determined the opening value of Ergon Energy's RAB as at 1 July 2010 to be $7105.4 million. The AER rolled forward Ergon Energy's RAB in the next regulatory control period using the PTRM, shown in table 16.8.

[1009] Energex, email to the AER, issue no: AER.ERG.24, 2 October 2009, confidential.
[1010] Energex, email to the AER, issue no: AER.ERG.34, 22 October 2009, confidential.

Table 16.8: AER forecast roll forward of Ergon Energy's regulatory asset base ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Opening RAB	7105.4	7859.4	8702.2	9 649.7	10 705.9
Net capex [a]	905.0	1001.1	1105.4	1227.5	1357.4
Indexation of the opening RAB	174.1	192.6	213.2	236.4	262.3
Straight–line depreciation	325.0	350.9	371.1	407.8	414.5
Closing RAB	7859.4	8702.2	9649.7	10 705.9	11 911.0

Note: The straight–line depreciation less the indexation of 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. Net capex also includes capitalised equity raising costs.

Depreciation

As discussed in chapter 10, the AER has not approved Ergon Energy's proposed depreciation allowance.

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 regulatory control period and to determine the depreciation allowance. Table 16.13 shows the resulting regulatory depreciation allowance.

Return on capital

The AER considers that Ergon Energy's proposed return on capital has been calculated in accordance with the PTRM. However, the amount is affected by the AER's conclusions regarding other inputs to the PTRM, such as the opening RAB (chapter 5), the capex allowance (chapter 7), and the WACC parameters (chapter 11).

The AER has determined the annual return on capital allowance by applying the WACC to Ergon Energy's opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.13 below.

The nominal vanilla WACC of 10.06 per cent is based on a post–tax nominal return on equity of 10.64 per cent and a pre–tax nominal return on debt of 9.68 per cent. These figures are calculated using observed market data as at 13 October 2009, and will be updated closer to the AER's final decision using Ergon Energy's nominated averaging period.

Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Ergon Energy of $1626.2 million (nominal) for the next regulatory control period.

Table 16.13 shows the annual opex allowance, which equates to an average amount of $325.2 million per annum in nominal terms.

Estimated taxes payable

Using the PTRM, the AER has modelled Ergon Energy's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this draft decision. Consistent with clause 6.5.3 of the NER, the amount of tax payable is estimated using:

- a 60 per cent gearing, based on the gearing of a benchmark efficient entity, rather than Ergon Energy's actual gearing
- a statutory company income tax rate of 30 per cent as determined by the AER, and
- a value of imputation credits (gamma) of 0.65.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 22.57 per cent for this draft decision. Table 16.9 shows the AER's estimate of Ergon Energy's tax payments.

Table 16.9: AER modelling of Ergon Energy's net tax allowance ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Tax payable	0.0	57.3	83.7	97.1	94.7
Value of imputation credits	0.0	37.3	54.4	63.1	61.5
Net tax allowance	0.0	20.1	29.3	34.0	33.1

Note: Ergon Energy has no tax allowance for 2010–11 due to the carry forward of tax losses from previous years.

Capital contributions

Under clause 11.16.3(b) of the NER, Ergon Energy has decided to continue with the QCA approach to the treatment of capital contributions and included forecast capital contributions in its RAB for the next regulatory control period. To prevent customers paying twice for contributed assets, Ergon Energy has included a revenue adjustment for forecast of capital contributions for the next regulatory control period in its PTRM, as discussed in chapter 4.

The AER investigated the claim by SPA that Ergon Energy had not presented the correct level of capital contributions it had received in 2007–08 and 2008–09. In response, Ergon Energy informed the AER that it undertook an internal review and reconciliation of gifted assets in late 2008 amid concerns that the reported amounts may not have been fully reflecting the true value.[1011] It further stated that the review and reconciliation substantiated that the values reported are appropriate, and identified a number of contributing factors that reduced the values of gifted assets, including:[1012]

- Ergon Energy does not know the actual costs incurred by third parties to construct new connection assets, so the works completed by third parties are capitalised based on Ergon Energy's internal estimates for the works. These estimates are based only on the direct costs of the gifted assets and exclude internal overheads.

- Ergon Energy identified delays in updating some components of the 'pricebooks' used to estimate the value of gifted assets. The estimated value of contributed assets increased after these components were updated. The updated components are reflected in the capital contributions forecast by Ergon Energy for the next regulatory control period.

- When developers were initially given the option to use third parties for the design and construction of subdivision assets, Ergon Energy stated it acted as an agent between developers and contractors, in that received payment from developers, and paid contractors. Hence these works are reported on the same basis as work managed internally using contractors, and are not classified as gifted assets in Ergon Energy's financial reporting, despite being done by third party providers. Ergon Energy stated the majority of works completed in 2007–08 were done on this basis. (Ergon Energy noted that offers to developers are no longer made under the initial model and that all new contestable works require developers to deal directly with contractors to procure completion, however, there is still a small amount of works outstanding which are offered under the initial model.)

- There is normally work in progress at the end of each financial year that is not able to be fully closed out and capitalised in time for the closing of the financial accounts.

- When a third party is used to deliver new customer connection and subdivision assets, the work is not capitalised until the project is fully completed and supply is available. This can result in developers seeing expenditure being incurred during a given year, yet that expenditure may not appear as gifted assets in Ergon Energy accounts until all final testing of the new assets is completed.

The AER notes that Ergon Energy made adjustments to its regulatory forecasts for gifted assets to account for the factors listed above. On the basis of the internal reconciliation and further information provided by Ergon Energy, the AER accepts the forecast capital contributions proposed by Ergon Energy for the next regulatory control period as being consistent with clause 6.21.2(3) of the NER.

In addition, the AER notes that an annual adjustment for any under/over recovery of capital contributions against forecasts will be made to Ergon Energy's MAR each year, as discussed in chapter 4.

[1011] Ergon Energy, email to the AER, Issue no: AER.ERG.20, 22 September 2009, confidential.
[1012] Ergon Energy, email to the AER, Issue no: AER.ERG.20, 22 September 2009, confidential.

Revenue adjustment for shared assets

Ergon Energy has included a revenue adjustment for expected use of shared assets for unregulated and alternative control services during the next regulatory control period in its PTRM. The AER considers these forecast amounts to be reasonable, being roughly comparable in size to previous adjustments approved by the QCA for this matter.

The AER also notes that any difference between expected and actual use of shared assets for unregulated and alternative control services will be accounted for by an annual adjustment to Ergon Energy's MAR (based on two year lagged data), as discussed in chapter 4.

Accelerated depreciation of destroyed assets

As discussed in chapter 10, the AER has decided to allow Ergon Energy to depreciate the remaining value of the assets destroyed by Cyclone Larry in March 2006 in the first year of the next regulatory control period. However, the AER has adjusted the nominal (end of year) value of this adjustment to $10.4 million in 2010–11 due to the error noted by Ergon Energy regarding the indexed value of these destroyed assets.[1013]

16.6 AER conclusion

The AER has calculated the Qld DNSPs' revenue requirements and X factors based on its decisions regarding the building block components.

16.6.1 Energex

The AER's draft decision results in a total revenue requirement over the next regulatory control period of $7158 million ($2009–10), compared to $7515 million proposed by Energex. The main reasons for this difference reflect the net effect of:

- removal of $748 million from Energex's forecast capex[1014]
- removal of $257 million from Energex's forecast opex[1015]
- a reduced allowance for tax, reflecting in part a higher gamma.
- a reduced allowance for equity raising costs
- a higher WACC than proposed by Energex.

1013 Ergon Energy, email to the AER, 4 September 2009.
1014 This figure excludes equity raising costs, which are to be added to the opening RAB and amortised.
1015 This figure excludes equity raising costs and debt raising costs.

Table 16.10: AER conclusion on Energex's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	87.1	97.2	108.9	120.6	121.7
Return on capital[a]	793.8	901.4	1015.5	1133.2	1252.0
Operating expenditure[b]	320.8	327.8	341.9	357.4	359.7
Tax allowance	32.2	35.5	39.1	43.0	45.9
Capital contributions	–64.6	–68.9	–70.9	–73.6	–75.7
Revenue from shared assets	–4.5	–5.3	–6.0	–6.5	–6.0
Annual revenue requirements	1165.8	1288.7	1429.7	1575.1	1698.7
Expected revenues	1180.6	1294.2	1418.7	1555.2	1704.8
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–23.03	–7.00	–7.00	–7.00	–7.00

Source: AER, PTRM.
(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

In deciding on Energex's X factors, the AER was mindful of clauses 6.5.9(2) of the NER, which requires the divergence between the expected revenues and the annual revenue requirement for the last year of the next regulatory control period to be minimised. On this basis, the AER reduced the X factors for 2012–13 to 2014–15 from –8.44 per cent to – 7.00 per cent, while it reduced the X factor in 2010–11 from –25.34 per cent to –23.03 per cent. The resulting impacts in terms of end use prices of the AER's decision to use these X factors, compared with Energex's proposal, is outlined in table 16.11.

Table 16.11: End user price impacts – Energex's proposal and AER draft decision (per cent)

	2010–11	2011–12	2012–13	2013–14	2014–15
Energex proposal	8.3	1.8	1.8	1.8	1.8
AER draft decision	7.4	1.2	1.2	1.2	1.2

Note: Calculations assume distribution network charges make up 40 per cent of an end user's bill and demand growth of 3.8 per cent per annum for the next regulatory control period.

The price impacts above exclude the effects of any annual revenue adjustments for such matters as under/over recovery of DUOS and any pass through costs. These adjustments will be accounted for as part of the annual price approval process.[1016]

16.6.2 Ergon Energy

The AER's draft decision results in a total revenue requirement over the next regulatory control period of $6364 million ($2009–10), compared to $6776 million proposed by Ergon Energy. The main reasons for this difference reflect the effect of:

- removal of $1020 million from Ergon Energy's forecast capex[1017]
- removal of $478 million from Ergon Energy's forecast opex[1018]
- a reduced allowance for tax, reflecting in part a higher gamma.
- a reduced allowance for equity raising costs
- the addition of $106 million to Ergon Energy's opening RAB as at 1 July 2005[1019]
- the correction of remaining asset lives, which has the effect of increasing the depreciation allowance
- a higher WACC than proposed by Ergon Energy.

[1016] Based on the forecasts included in Energex's regulatory proposal, these adjustments are likely to reduce the size of the price increase for the first year of the next regulatory control period.
[1017] This figure excludes equity raising costs, which are to be added to the opening RAB and amortised.
[1018] This figure excludes equity raising costs and debt raising costs.
[1019] This increase was due to the use of revised CPI data in the roll forward of Ergon Energy's asset base over the current regulatory control period. See chapter 5 for details.

Table 16.12: AER conclusion on Ergon Energy's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	151.0	158.3	157.9	171.4	152.2
Return on capital[a]	715.1	791.0	875.8	971.1	1077.4
Operating expenditure[b]	328.3	335.1	327.7	323.5	311.6
Tax allowance	0.0	20.1	29.3	34.0	33.1
Capital contributions	–112.0	–121.2	–107.9	–117.5	–135.2
Revenue from shared assets	–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation	10.4				
Annual revenue requirements	1089.6	1180.0	1279.4	1379.0	1435.7
Expected revenues	1096.6	1178.5	1266.5	1361.1	1462.8
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors [c] (%)	–26.63	–4.90	–4.90	–4.90	–4.90

Source: AER, PTRM.
(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

In deciding on Ergon Energy's X factors, the AER was (as for Energex) mindful of clauses 6.5.9(2) of the NER. On this basis, the AER reduced the X factors for 2012–13 to 2014–15 from –7.69 per cent to – 4.90 per cent, while it reduced the X factor in 2010–11 from –27.05 per cent to –26.63 per cent. The resulting impacts in terms of end use prices of the AER's decision to use these X factors, compared with Ergon Energy's proposal, is outlined in table 16.13 below.

Table 16.13: End user price impacts – Ergon Energy proposal and AER draft decision (per cent)

	2010–11	2011–12	2012–13	2013–14	2014–15
Ergon Energy proposal	9.3	1.8	1.8	1.8	1.8
AER draft decision	9.2	0.7	0.7	0.7	0.7

Note: Calculations assume distribution network charges make up 40 per cent of an end user's bill and demand growth of 3.0 per cent per annum for the next regulatory control period.

The price impacts above exclude the effects of any annual revenue adjustments for such matters as under/over recovery of DUOS and any pass through costs. These adjustments will be accounted for as part of the annual price approval process.

16.7 AER draft decision

In accordance with clause 6.12.1(2)(i) of the NER, the AER refuses to approve the annual revenue requirement proposed by Energex.

In accordance with clauses 6.12.1(2)(ii) and 6.3.2(a)(4) of the NER, Energex's regulatory control period is from 1 July 2010 to 30 June 2015.

In accordance with clause 6.12.1(11) of the NER, the X factors to apply to Energex are as specified in table 16.10 of this draft decision.

In accordance with clause 6.3.2(a)(1) of the NER, Energex's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.10 of this draft decision.

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of Energex's regulatory asset base is as specified in section 16.5.2 of this draft decision.

In accordance with clause 6.3.2(a)(5) of the NER, any other amounts, values or inputs on which Energex's building block determination is based are as specified in sections 16.5 and 16.6 of this draft decision.

In accordance with clause 6.12.1(2)(i) of the NER, the AER refuses to approve the annual revenue requirement proposed by Ergon Energy.

In accordance with clauses 6.12.1(2)(ii) and 6.3.2(a)(4) of the NER, Ergon Energy's regulatory control period is from 1 July 2010 to 30 June 2015.

In accordance with clause 6.12.1(11) of the NER, the X factors to apply to Ergon Energy are as specified in table 16.12 of this draft decision.

In accordance with clause 6.3.2(a)(1) of the NER, Ergon Energy's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.12 of this draft decision.

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of Ergon Energy's regulatory asset base is as specified in section 16.5.3 of this draft decision.

In accordance with clause 6.3.2(a)(5) of the NER, any other amounts, values or inputs on which Ergon Energy's building block determination is based are as specified in sections 16.5 and 16.6 of this draft decision.

17 Alternative control – street lighting services

17.1 Introduction

Clause 6.2.2(a) of the NER divides direct control services into standard control services and alternative control services.

This chapter sets out the AER's consideration of the Qld DNSPs' street lighting services control mechanism and how compliance with that mechanism is to be demonstrated by the Qld DNSPs in the next regulatory control period.

Classification of the Qld DNSPs' street lighting services is set out in chapter 2 of this draft decision.

17.2 Regulatory requirements

Clause 6.8.1 of the NER requires the AER publish a framework and approach in anticipation of every distribution determination, which amongst other things includes the control mechanisms to apply to direct control services.

Clause 6.2.5(d) outlines the factors the AER must have regard to in deciding on the control mechanism to apply to alternative control services. Clause 6.2.5(b) lists the control mechanisms that the AER may apply to direct control services. One option that the AER may apply is a cap on the prices of individual services, as a control mechanism, under clause 6.2.5(b)(2) of the NER.

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 mechanism to be applied in a distribution determination must be as set out in the framework and approach.

17.3 AER framework and approach

The AER determined that a price cap control mechanism would apply to the Qld DNSPs' street lighting services in the next regulatory control period. The AER stated that a limited building block approach would be used to establish the efficient costs of providing street lighting services in the first regulatory year of the next regulatory control period, and that a price path would be established for the remaining regulatory years of the next regulatory control period.[1020]

[1020] AER, *Final decision, Framework and approach paper: Classification of services and control mechanism*, August 2008, pp. 43–44.

17.4 Queensland DNSP regulatory proposals

Energex

Control mechanism

Energex stated that its street lighting services are categorised into major and minor street lights and is distinguished with reference to the road category where the street light is located. Under both categories the applicable charge depends on whether the street light construction is funded by Energex or the customer.[1021]

Consistent with the framework and approach, Energex proposed a price cap form of control based on a limited building block approach to apply to its street lighting services. Where a non–standard street light asset is requested the incremental cost difference (between the standard and non–standard asset) will be charged as a quoted service and therefore subject to a price cap to be developed using a formula based approach. All customers will receive an ongoing maintenance charge.[1022]

Opening street lighting asset base

Transitional issue

Energex stated that in the current regulatory control period all of its contributed and non–contributed street lighting assets were recognised in the regulatory asset base (RAB) consistent with the QCA approved approach. In relation to contributed assets, the annual regulated revenue allowance was reduced by the value of the contributed asset in the year the asset was received to avoid double counting of the contributed assets.[1023] Energex constructed street lighting assets (non–contributed assets) which were treated like any other prescribed service, that is, the full asset value was added to the RAB to be recovered over the life of the asset.

Energex stated that as street lighting services have been reclassified as alternative control services, under clause 6.5.1(a) of the NER it is required to remove street lighting assets from the RAB.

Energex proposed that the residual non–contributed street light assets be removed from the RAB and form the opening street lighting asset base as at 1 July 2010. It proposed that the residual cost of contributed street lighting assets remain within the RAB as historically benefits from the revenue reduction relating to these assets were applied to all standard asset customers reflecting that they were the ultimate beneficiaries.[1024]

Opening asset base 1 July 2010

Energex proposed that only non–contributed assets should be included in its opening street lighting asset base for 1 July 2010. Energex stated that the full asset value of all of its street lighting assets as at 1 July 2010 is $268 million.

[1021] Energex, *Regulatory proposal*, July 2009, p. 302.
[1022] Energex, *Regulatory proposal*, July 2009, p. 303.
[1023] A contributed asset is an asset constructed by the customer (or its agent) at the customer’s expense and gifted to Energex or could also be a non standard asset constructed by Energex.
[1024] Energex, *Regulatory proposal*, July 2009, p. 304.

For the purpose of determining its opening street lighting asset base for the next regulatory control period, Energex developed a methodology to determine the asset value attributable to non–contributed assets. This methodology is based on an apportionment of assets weighted by replacement costs and the number of lights.[1025]

Of the asset value attributed to street lighting assets, Energex stated that $96 million is comprised of non–contributed assets, which it proposed would form its opening street lighting asset base, and $172 million of contributed assets, which would remain in the RAB. Energex therefore proposed an opening street lighting asset base for the next regulatory control period of $96 million.[1026]

Forecast capex

Energex proposed a forecast capex requirement of $35 million ($2009–10) for the next regulatory control period, as set out below in table 17.1. The forecast capex requirement is net of contributed assets and reflects assets to be constructed and provided by Energex.[1027]

Table 17.1: Energex forecast capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex forecast capex	6.8	6.8	7.0	7.1	6.9	34.6

Source: Energex, *Regulatory proposal*, July 2009, table 21.6, p. 310.

Forecast opex

Energex proposed a forecast opex requirement of $71 million in the next regulatory control period, as set out below in table 17.2.[1028]

Limited building block annual revenue requirement

Energex's calculation of annual revenue requirements and X factors is contained in a completed post–tax revenue model (PTRM) submitted as part of its regulatory proposal, and is summarised in table 17.2.[1029]

Energex proposed an X factor of 20.20 per cent (that is, a real decrease) for the first year of the regulatory control period to account for the decrease in revenue requirements between 2009–10 and 2010–11. It also proposed an X factor of –3.60 per cent for years 2011–12 to 2014–15.[1030]

[1025] Energex, *Regulatory proposal*, July 2009, p. 312.
[1026] Energex, *Regulatory proposal*, July 2009, pp. 311–313.
[1027] Energex, *Regulatory proposal*, July 2009, pp. 309–310.
[1028] Energex, *Regulatory proposal*, July 2009, p. 311.
[1029] Energex, *Regulatory proposal*, July 2009, p. 315.
[1030] Energex, *Regulatory proposal*, July 2009, p. 315.

Table 17.2: Energex revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.7	7.3	7.9	8.6	9.3
Return on capital	9.1	9.2	9.2	9.2	9.1
Tax allowance	6.0	6.1	6.2	6.2	6.2
Operating expenditure	12.6	13.4	14.1	14.9	15.5
Adjustment for non–system revenue allocation	1.9	2.4	2.6	2.9	2.6
Annual revenue requirement[a]	36.4	38.4	40.0	41.7	42.7
X factors[b] (percentage)	20.20	–3.60	–3.60	–3.60	–3.60

Source: Energex, *Regulatory proposal*, July 2009, tables 21.14 and 21.15, p. 315.
Notes: Totals may not add due to rounding.
(a) This is the unsmoothed annual revenue requirement.
(b) Negative values for X indicate real price increases under the CPI–X formula.

Indicative prices

Energex provided the indicative prices set out in table 17.3 for the provision, construction and maintenance of standard street lights for the next regulatory control period.[1031]

Table 17.3: Energex indicative prices for street lighting services (dollars per light per day, GST exclusive)

	First year price path (%)	2010–11	2011–12	2012–13	2013–14	2014–15
Major non–contributed	–9.64	0.86	0.90	0.94	0.98	1.02
Major contributed	49.88	0.25	0.26	0.28	0.29	0.30
Minor non–contributed	–73.30	0.37	0.38	0.40	0.42	0.43
Minor contributed	–32.28	0.11	0.11	0.12	0.12	0.13
Price path (%)		n/a	4.38	4.38	4.38	4.38

Source: Energex, *Regulatory proposal*, July 2009, table 21.16, p. 316; and Energex, response to information request AER.EGX.04.09, 28 August 2009, confidential.
Notes: A positive price path indicates a price increase.

Ergon Energy

Control mechanism

Ergon Energy identified three categories of street lighting services for the next regulatory control period:[1032]

[1031] Energex, *Regulatory proposal*, July 2009, pp. 316–317.

1. the provision of new street lighting assets (category 1)
2. the operation, repair, replacement and maintenance of street lighting assets (category 2)
3. the alteration and relocation of existing street lighting assets (category 3).

Ergon Energy proposed to charge street lighting service categories one and three as a quoted service and therefore subject to a price cap to be developed using a formula based approach. It stated that the defining characteristic of these service categories is that they are requested by an individual customer and therefore the service must be tailored to meet the customer's specific requirements hence a fixed price cannot be determined in advance based on forecast costs and volumes.[1033]

Ergon Energy proposed a price cap form of control based on a limited building block approach to apply to its category 2 street lighting services.[1034]

Opening street lighting asset base

Ergon Energy proposed to establish an alternative control services' street lighting asset base by removing the existing street lighting assets from its opening RAB for standard control services as at 1 July 2005. It removed $47 million of assets from its opening RAB as at 1 July 2005. Ergon Energy rolled forward its street lighting asset base and proposed an opening asset base for the next regulatory control period of $52 million as at 1 July 2010.[1035]

Forecast capex

Ergon Energy proposed a forecast capex requirement of $19 million ($2009–10) for the next regulatory control period, as set out below in table 17.4.[1036]

Table 17.4: Ergon Energy forecast capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Forecast capex	2.8	3.1	3.5	4.3	5.0	18.7

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 148, p. 461.

Forecast opex

Ergon Energy proposed a forecast opex requirement of $79 million in the next regulatory control period, as set out below in table 17.5.[1037]

Limited building block annual revenue requirement

Ergon Energy's calculation of annual revenue requirements and X factors is contained in a completed PTRM submitted as part of its regulatory proposal, and are summarised in table 17.5.[1038]

[1032] Ergon Energy, *Regulatory proposal*, July 2009, p. 456.
[1033] Ergon Energy, *Regulatory proposal*, July 2009, p. 456.
[1034] Ergon Energy, *Regulatory proposal*, July 2009, p. 456.
[1035] Ergon Energy, *Regulatory proposal*, July 2009, PLRFM Submission Model, confidential.
[1036] Ergon Energy, *Regulatory proposal*, July 2009, p. 460.
[1037] Ergon Energy, *Regulatory proposal*, July 2009, p. 479.

Ergon Energy proposed an X factor of –66.04 per cent (that is, a real increase) for the first year of the regulatory control period to account for the increase in revenue requirements between 2009–10 and 2010–11. It proposed an X factor of –1.00 per cent for years 2011–12 to 2014–15.[1039]

Table 17.5: Ergon Energy revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.0	6.3	6.7	7.0	7.5
Return on capital	5.0	4.8	4.6	4.5	4.4
Tax allowance	1.6	1.7	1.7	1.7	1.7
Operating expenditure	15.1	15.0	15.5	16.3	17.0
Annual revenue requirement[a]	26.4	26.6	27.3	28.4	29.5
X factors[b] (%)	–66.04	–1.00	–1.00	–1.00	–1.00

Source: Ergon Energy, *Regulatory proposal*, July 2009, pp. 478–480, and Ergon Energy, *Regulatory proposal*, July 2009, PLPTRM Submission Model, confidential.
Notes: Totals may not add due to rounding.
(a) This is the unsmoothed annual revenue requirement.
(b) Negative values for X indicate real price increases under the CPI–X formula.

Indicative prices

Ergon Energy provided the indicative prices set out in table 17.6 for the provision of its category 2 street light services in the next regulatory control period. However, it stated that the indicative prices are not the basis on which it intends to charge for these services.[1040]

Table 17.6: Ergon Energy indicative prices for category 2 street lighting services (dollars per light per year, $2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Street lighting	198.5	196.9	195.3	193.7	192.1

Source: Ergon Energy, *Regulatory proposal*, July 2009, table 160, p. 482.

17.5 Submissions

The AER received three submissions that addressed street lighting services. The submissions were from the Local Government Association of Queensland (LGAQ), Local Buy Pty Ltd (Local Buy) and SPA Consulting (SPA).

The LGAQ has concerns surrounding Ergon Energy's proposal to supply new street lighting assets as a quoted service rather than a tariff structure. The LGAQ also stated

[1038] Ergon Energy, *Regulatory proposal*, July 2009, PLPTRM Submission Model confidential.
[1039] Ergon Energy, *Regulatory proposal*, July 2009, p. 481.
[1040] Ergon Energy, *Regulatory proposal*, July 2009, p. 482.

that Ergon Energy’s opex proposal on street lighting assets will result in a significant increase in costs to customers.[1041]

Local Buy submitted that there are examples where prices do not reflect maintenance costs, cost allocations or reductions in capex. Local Buy also stated that Energex’s regulatory proposal does not encourage the use of energy efficient lights.[1042]

SPA Consulting submitted that Ergon Energy’s bulk lamp replacement schedule for metal halide lamps is inappropriate.[1043]

17.6 Issues and AER consideration

Clause 6.12.3 of the NER which sets out the extent of the AER’s discretion in making a distribution determination states, at subclause (c), that the control mechanism must be as set out in the relevant framework and approach paper.[1044] Clause 6.12.1(13) of the NER requires the AER to make a decision on how compliance with the relevant control mechanism is to be demonstrated.

The AER’s framework and approach decision required the DNSPs to provide their proposed costs of providing street lighting services using a limited building block approach. The AER stated that it would assess the efficiency of these costs in setting the price for the first regulatory year in the next regulatory control period and, also, in developing a price path for the remaining regulatory years of the next regulatory control period.

17.6.1 Control mechanism

Clause 6.4.3(a) of the NER sets out the building blocks that form the annual revenue requirement. The AER’s limited building block approach for the Qld DNSPs street lighting services does not incorporate all the building blocks set out in chapter 6 of the NER. In particular, the building blocks relating to incentive schemes and adjustments from the current regulatory control period. The framework and approach specified that the Qld DNSPs may propose simplifying assumptions within the limited building block approach.[1045]

Energex

Consistent with the framework and approach, Energex proposed a price cap form of control based on a limited building block approach to apply to its street lighting services.[1046] Energex proposed that where a non–standard street light asset is

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1041 LGAQ, *Submission to Australian Energy Regulator on regulatory proposals for Queensland electricity DNSPs*, 25 August 2009.

1042 Local Buy is a company that is wholly owned by the Local Government Association of Queensland. Its role is to provide procurement services to Queensland local Governments. Local Buy, *Queensland distribution determination for 2010–15*, 27 August 2009.

1043 SPA Consulting, *Submission to the Australian Energy Regulator Queensland distribution determinations for the period 2010 – 2015*, 28 August 2009.

1044 Although clause 6.8.1(h) provides that a framework and approach paper is not binding on the AER (or a DSNP), that clause is subject to clause 6.12.3.

1045 AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008, p. 41.

1046 Energex, *Regulatory proposal*, July 2009, pp. 307–309.

requested the incremental cost difference (between the standard and non–standard asset) will be charged as a quoted service and, therefore, subject to a price cap. Energex explained that a price cap was to be developed using a formula based approach and that customers of these services will still receive an ongoing maintenance charge.[1047]

The AER sought further information from Energex in relation to its non–standard street lighting services. Energex stated that standard equipment is used to design and configure street lighting assets and that each luminaire is classified as either major or minor according to its lamp size. These groups of assets form the basis of the prices for their respective tariff class and are considered to be standard assets.[1048]

Energex stated that a service is regarded as a non–standard installation where it would not fully recover the cost of the service through its annual (major or minor) prices and that the incremental cost therefore represents the uneconomic cost of the service. The incremental cost is calculated as the shortfall between the present value of the expected charges paid by the customer over the life of a standard street lighting asset and the estimated cost of providing the non–standard service. The AER understands this is consistent with Energex's capital contributions policy that was approved by the QCA.

The AER accepts Energex's proposed limited building block to apply to its street lighting services and it considers this approach is consistent with the framework and approach.

Ergon Energy

Consistent with the framework and approach, Ergon Energy proposed a price cap form of control based on a limited building block approach that incorporates costs associated with the operation, repair, replacement and maintenance of street lighting assets (category 2).[1049] The AER considers this approach is consistent with the framework and approach.

Ergon Energy proposed to charge for the provision of new street lighting assets (category 1) as a quoted service, developed on a formula based price cap control mechanism. It considered that the defining characteristic of these services is that they are requested by an individual customer and therefore the service must be tailored to meet the customer's specific requirements. Hence, Ergon Energy considered that a fixed price for new street lighting assets cannot be determined in advance of each service being requested and therefore it could not accurately forecast costs and volumes.[1050]

Ergon Energy considered that its proposed treatment of new street lighting assets also complies with the AER's framework and approach as these services are to be regulated under a building block approach and a price cap control mechanism. It stated that the building block would be the build up of the actual costs of installing

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[1047] Energex, *Regulatory proposal*, July 2009, p. 303, confidential.
[1048] Energex, response to information request AER.EGX.04.09, 14 August 2009, confidential.
[1049] Ergon Energy, *Regulatory proposal*, July 2009, p. 456.
[1050] Ergon Energy, *Regulatory proposal*, July 2009, p. 456.

new street lights on a customer by customer basis rather than as the aggregate of street lighting services.[1051]

The AER notes the LGAQ's concern with Ergon Energy's proposal to supply new street lighting assets as a quoted service. The LGAQ was concerned that limited levels of competition, most notably in more remote regions, could lead to higher prices for the provision of new street lights leading to an increase in cost for the installation of new street lights relative to the current arrangement.[1052]

The QCA's 2005 distribution determination provided Ergon Energy with a capital allowance for new assets, including street lighting assets, as part of the revenue cap.[1053] In the current regulatory control period, Ergon Energy's street lighting prices are separated into either lighting major or lighting minor categories in recognition of the different costs associated with different lamp sizes.[1054]

The framework and approach paper set out the AER's consideration of the factors under clause 6.2.5(d) of the NER in deciding on the control mechanism to apply to street lighting services. Clause 6.2.5(c)(3) requires the AER have regard for the regulatory arrangements applicable to the relevant service immediately before the commencement of the distribution determination. The AER considers that Ergon Energy proposed treatment of the provision of new street lighting assets is not consistent with the AER's framework and approach paper and is an incorrect interpretation of the limited building block price cap control mechanism.

The AER notes that Ergon Energy proposed to continue the same pricing categories (major lighting and minor lighting) in the next regulatory control period. However, it proposed that in developing these two prices in the next regulatory control period, it would only take into account replacement capex and not new capex but combine the opex associated with new street lighting assets and existing street lighting assets.[1055]

This approach is in essence based on capex associated with the provision of new street lighting assets being recovered on a quoted basis whilst opex is recovered via a price cap developed using the limited building block approach. Based on the pricing information provided by Ergon Energy it is unclear whether it intends to have a tariff that separately captures only the cost associated with opex. If such a tariff is not provided, it is likely that new street lighting customers will be subsidising capex costs relating to existing street lighting assets since a single tariff is charged to both new and existing street lighting customers.

The AER considers that the limited building block approach avoids this outcome if the forecast capex associated with new street lighting assets is included in deriving the limited building block revenue requirement in the next regulatory control period. This

1051 Ergon Energy, *Regulatory proposal*, July 2009, p. 456.
1052 LGAQ, *Submission to the AER*, 25 August 2009.
1053 Under the revenue cap the cost of new street lighting assets was not directly attributable to individual customers but was apportioned to all street lighting customers.
1054 Ergon Energy, *Network Use of System Tariff Guide*, 31 May 2009, p. 27.
1055 Ergon Energy, *Regulatory proposal*, July 2009, p. 468; and Ergon Energy, *response to information request*, AER.ERG.06.09, 21 August 2009, confidential.

allows Ergon Energy to continue, as proposed, the same pricing approach (major lighting and minor lighting) as in the current regulatory control period.

The AER therefore requires Ergon Energy to provide a forecast capex allowance for new street lighting assets to be provided in the next regulatory control period as part of its revised regulatory proposal. This allowance is to be incorporated as part of the limited building block approach proposed for its category 2 street lighting services. The AER will assess the appropriate forecast capex allowance as part of its final determination.

Ergon Energy also proposed to charge for the alteration and relocation street lighting service (category 3) as a quoted service.[1056] The AER understands that the service to be provided is the alteration or relocation of an asset, in this case, a street lighting asset. In chapter 2 of this draft decision, the AER classified Ergon Energy's supply enhancement and rearrangement of network asset services as quoted services, consistent with Ergon Energy's regulatory proposal and the framework and approach paper. The AER considers its classification of supply enhancement and rearrangements of network asset services as quoted services accurately captures Ergon Energy proposed treatment of its category 3 street lighting services. The AER does not consider there is a need to further separate the enhancement or rearrangement of street lighting assets from other assets.

Consistent with its classification of services the AER requires Ergon Energy to charge for a supply enhancement or rearrangement of any asset, including street lighting assets, as a quoted service. The AER's assessment of the Qld DNSPs' alternative control (quoted and fee based) services is set out in chapter 18 of the draft decision.

17.6.2 Opening street lighting asset base

Clause 6.5.1(a) of the NER defines a DNSP's RAB as the value of assets used by the DNSP to provide standard control services. Further, clause S6.2.1(7) requires that:

> the previous value of the RAB must be reduced by the value of an asset where the asset was previously used to provide standard control services (or their equivalent under previous regulatory system) but, as a result of a change to the classification of a particular service under Part B, is not to be used for that purpose for the relevant regulatory control period.

During the current regulatory control period, the Qld DNSPs' street lighting assets were classified as prescribed distribution services and have been included in the RAB.

Energex

Transitional street lighting asset base

Under Energex's current approach, contributed street lighting assets received are netted off from the revenue pool used to calculate prices for all standard asset customers (SACs) in the regulatory year the asset was commissioned. The AER notes that the benefit of the reduction in the revenue pool has not been received by street lighting customers alone, rather, all SACs have benefited as a result of the reduction in the revenue pool.

[1056] Ergon Energy, *Regulatory proposal*, July 2009, p. 456.

Energex proposed to separate its contributed and non–contributed street lighting assets and retain the contributed street lighting assets in the RAB to limit pricing distortions.[1057] The AER agrees that this approach results in a more equitable outcome as removing these assets from the RAB and allocating them to the street lighting asset base would mean that the residual asset cost would be funded by street lighting customers alone even though other customers have received some benefit in the past.

The AER notes that clause 11.16.3 of the NER permits the Qld DNSPs to retain in the next regulatory control period the approach allowed in the QCA's 2005 distribution determination regarding the treatment of the RAB.

The AER considers that Energex's proposed approach that the contributed street lighting assets remain in the RAB is appropriate. It reflects the approach applied by the QCA in the 2005 determination and is consistent with the NER.

The AER further notes that Energex's current approach to non–contributed street lighting assets is that these assets are treated like any other prescribed service, that is, there is no capital contribution or reduction of the revenue pool. Accordingly, the AER considers that Energex's proposed approach to remove these assets from the RAB to form the opening street lighting asset base as at 1 July 2010 is consistent with clauses 6.5.1(a) and S6.2.1(e)(7) of the NER.

Opening asset values

The AER notes that Energex's proposed valuation of its street lighting assets was based on the existing asset valuations and has been adjusted for actual capex, depreciation and indexation, during the current regulatory control period.

In chapter 5 of this draft decision the AER reviewed Energex's proposed opening RAB adjustments and the cost inputs to the roll forward model (RFM) for the current regulatory control period and on the basis of its review the AER is satisfied that Energex's opening asset value for street lighting assets has been derived in accordance with the requirements of the RFM. The roll forward of Energex's street lighting asset base is shown in table 17.7.

Table 17.7: Energex's street lighting asset base at 1 July 2010 ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11
Opening RAB (1 July)	236.0	241.7	248.6	258.7	262.0	268.4
Actual capital expenditure/additions	17.4	21.3	21.4	20.8	25.6	
Depreciation	–18.8	–20.3	–21.9	–23.9	–25.6	
Indexation	7.0	5.9	10.5	6.4	6.4	
Closing RAB (30 June)	241.7	248.6	258.7	262.0	268.4	

Source: Energex, *Regulatory proposal*, July 2009, table 21.9, p. 312.
Notes: Totals may not add due to rounding.

[1057] Energex, *Regulatory proposal*, July 2009, p. 304.

The AER also reviewed Energex's methodology for separating non–contributed assets from contributed assets and notes that it is based on an apportionment of assets weighted by replacement costs and the number of lights. The AER is satisfied that there is no double counting of assets and no cross–subsidisation between the two types of services. The AER is therefore satisfied that the proposed opening street lighting asset base for the next regulatory control period of $96 million is appropriate as set out at table 17.8.

Table 17.8: Energex street lighting asset base at 1 July 2010 ($m, nominal)

	2010–11
Closing RAB at 30 June 2010	268.4
Less asset value for contributed assets	–172.3
Opening street light asset base at 1 July 2010	96.1

Source: Energex, *Regulatory proposal*, July 2009, table 21.10, p. 312.

Ergon Energy

The AER notes Ergon Energy's proposed approach to remove all street lighting assets (contributed and non–contributed) from the opening RAB as at 1 July 2005 and then roll forward this asset base to form the opening street lighting asset base as at 1 July 2010. The AER is satisfied that the proposed approach of removing street lighting assets from the RAB is consistent with clauses 6.5.1(a) and S6.2.1(e)(7).

Based on this approach, as indicated at table 17.19, Ergon Energy proposed to remove $47 million from its opening RAB as at 1 July 2005 to account for these street lighting assets which it then rolled forward to form its proposed opening street lighting asset base of $52 million as at 1 July 2010.

The AER reviewed Ergon Energy's proposed opening RAB adjustments and the cost inputs to the RFM for the current regulatory control period. It has also cross checked these against Ergon Energy's regulatory accounts. As discussed in Chapter 5, Ergon Energy did not apply the QCA's method to determine the CPI input into the RFM for the current regulatory control period. The AER amended these inputs to the RFM to reflect the QCA indexation method.

The AER considers that the opening value of Ergon's street lighting assets as at 1 July 2010, after applying the revised CPI figures, should be $53 million. The AER considers that the revised opening street lighting asset base set out in table 17.9 is consistent with the RFM and meets the requirements of the NER.

Table 17.9: Ergon Energy street lighting asset base at 1 July 2010 ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11
Opening RAB (at 1 July)	47.0	46.6	52.9	59.1	55.8	53.3
Actual capital expenditure/additions	2.9	10.2	9.7	1.6	2.6	
Depreciation	–4.7	–5.0	–5.7	–6.4	–6.7	
Indexation	1.4	1.1	2.2	1.5	1.5	
Closing balance 30 June	46.5	52.9	59.1	55.8	53.3	

Source: Ergon Energy, PLRFM Data Model, 24 November 2009, confidential.
Notes: Totals may not add due to rounding.

17.6.3 Limited building block elements

17.6.3.1 Demand forecasts

Energex

Energex forecast demand growth for street lighting services of 0.24 per cent for non–contributed street lights and 2.92 per cent for contributed street lights in each regulatory year of the next regulatory control period.[1058] Energex developed its forecasts by taking the average annual growth for each category (contributed and non–contributed) of street light from 2002–03 to 2007–08 as a proportion of the total street light population and then applied this average proportion to each street lighting category.

The AER conducted a simple linear regression in order to assess the reasonableness of Energex's demand forecasts. The AER considers that Energex's proposed methodology not to be statistically robust, but, the resulting demand forecasts are not unreasonable and are broadly consistent with the AER's linear regression. Therefore, the AER accepts Energex's proposed street lighting demand forecasts.

Ergon Energy

Ergon Energy forecast demand growth for its street lighting services of 2.3 per cent in each regulatory year of the next regulatory control period. It stated this forecast is based on the average growth in customer connections over the four years to 2007–08.[1059] The AER notes that Ergon Energy, like Energex, forecast a continuation of business as usual conditions. The AER considers this is reasonable and accepts Ergon Energy's street lighting demand forecasts.

17.6.3.2 Forecast capex

Energex

Energex stated that its forecast capex, set out in table 17.1, reflected non–contributed assets and was based on historical observations of usage and minimum design

[1058] Energex, *Regulatory proposal*, July 2009, p. 314.
[1059] Ergon Energy, *Regulatory proposal*, July 2009, p. 459.

requirements.[1060] The AER notes that Energex's street lighting capex proposal reflects a continuation of business as usual conditions.

Energex stated that the driver for its capex program is requests from road controlling authorities but the forecast capex is based on historical trends.[1061] It also stated that it has made no allowances for street light specific projects or programs.[1062] The AER understands that Energex expenses (rather than capitalises) all asset replacements and has not identified any replacement capex.[1063] Energex's capex proposal only represents new street lighting assets.

The AER notes that to determine cost reflective capex forecasts it is more appropriate to expand the street light asset base so that forecast costs can be made against a detailed listing of lamp sizes and luminaire types. Energex's proposal is based on a continuation of business as usual conditions consisting of two street light asset categories (major and minor).In the absence of further information or concerns raised in submissions by interested parties the AER considers that it is reasonable to accept Energex's proposed capex.

Energex identified an error in relation to the forecast capex input to its street lighting PTRM that understated its forecast capex and forecast revenues. Energex stated it had deducted capital contributions twice.[1064] The AER's review of Energex's initial and revised PTRM confirms this error. The AER has corrected this error as part of this draft decision and considers the revised forecast capex of $97 million as Energex's proposal.

The AER's assessment of Energex's proposed material cost escalators is set out in appendix H of this draft decision. The AER considers that Energex should apply its respective material cost escalators to its street lighting capex consistent with appendix H, in which the AER made a number of adjustments to the material cost escalators proposed by Energex. Following a request from the AER, Energex modelled its street lighting capex in accordance with the material cost escalators set out in appendix H, which results in a $7.2 million adjustment to its forecast capex.

Following its review of Energex's capex proposal the AER made the following adjustments:

- $7.2 million dollar reduction to total street lighting capex, applied across all components of forecast capex, to account for errors in the application of input cost escalators.

- $0.6 million addition to street lighting capex to account for the reallocation of overheads.

[1060] Energex, *Regulatory proposal*, July 2009, p. 310.
[1061] A road controlling authority is the party responsible for the road carriage way, either the local Government (council) or the Queensland Department of Main Roads.
[1062] Energex, response to information request AER.EGX.04.05, 14 August 2009, confidential.
[1063] Energex, response to information request AER.EGX.04.05, 14 August 2009, confidential.
[1064] Energex, response to information request AER.EGX.04.04, 14 August 2009, confidential.

As a result of its analysis of the information provided by Energex, the AER is not satisfied that the proposed street lighting capex allowance reasonably reflect the capex criteria, including the capex objectives.

The AER considers that making a $6.6 million reduction to Energex's forecast capex is likely to result in street lighting capex that reasonably reflect the capex criteria, including the capex objectives, and are the minimum adjustments necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

Table 17.10: AER conclusion Energex's capex allowance (net of capital contributions) ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed capex[a]	18.2	18.9	19.5	20.0	20.3	96.9
Adjustments to cost escalators	–1.0	–1.2	–1.5	–1.7	–1.9	–7.2
Variance to overhead reallocation	0.3	0.1	0.1	0.0	0.1	0.6
AER capex allowance	17.5	17.8	18.2	18.4	18.4	90.3

Source: Energex, email to AER, 23 November 2009 (confidential).
Notes: Totals may not add due to rounding.
(a) Energex's revised forecast capex after correcting its double counting of capital contributions.

Ergon Energy

Ergon Energy did not propose any forecast capex associated with the provision of new street lighting assets in the next regulatory control period. This approach is inconsistent with the control mechanism set out in the framework and approach. Ergon Energy is required to propose forecast capex for new street lighting assets as part of its revised regulatory proposal.

Ergon Energy proposed replacement capex associated with the:[1065]

- replacement of luminaires
- replacement of brackets
- replacement of poles
- replacement and disposal of asbestos sealed luminaires
- the upgrading to energy efficient luminaires.

Ergon Energy's Network Assets Replacement Maintenance Capex Opex Summary model demonstrates that the estimated incidence of luminaire, bracket and pole replacement and the replacement and disposal of asbestos sealed luminaires accurately reflects historic trends and its forecast demand growth in the total street

[1065] Ergon Energy, *Regulatory proposal*, July 2009, p. 461.

light population.[1066] Ergon Energy has essentially extrapolated business as usual conditions and this is reasonable. The AER also notes that Ergon Energy expenses the replacement of lamps.

Ergon Energy stated that it is a participant in the Queensland Government's energy efficient street lighting trial. The trial is designed to analyse the performance of various lamp technologies under a range of environmental and network conditions and recommend the most appropriate lamp for particular conditions. Ergon Energy anticipated that the Queensland Government's trial would result in a rollout of the chosen luminaire across its network and therefore forecast a rollout of replacement energy efficient luminaires commencing in 2011–12.[1067]

The AER notes that it remains uncertain whether the Queensland Government will mandate an energy efficient street lighting rollout or when the Qld DNSPs would be required to commence any such rollout. At this time, Ergon Energy is not required to replace existing luminaires with energy efficient luminaires. Further, the trial is in part to determine the appropriate luminaire technology for particular environmental conditions. The AER notes that it is not possible to accurately forecast the costs associated with the potential rollout as there is considerable uncertainty regarding the specific luminaire technology to be included in the rollout. Therefore, the AER considers that the cost of the rollout cannot realistically be identified.

Local Buy was concerned with the lack of any incentive mechanism to encourage Queensland street lighting customers to move towards energy efficient lights, apart from the energy charge in cents per kWh.[1068]

The AER recognises the importance of energy efficient initiatives and acknowledges the concerns raised by Local Buy regarding the incentives for the Qld DNSPs to adopt energy efficient lighting as opposed to other luminaire types. However, the AER does not consider it appropriate to approve any capex associated with this rollout given the above mentioned uncertainties. The AER's principal concern is that in the event that the program does not proceed, customers will have paid for a program that does not take place. The AER notes that Energex proposed to utilise the cost pass through arrangements in the event that the energy efficient luminaire rollout is mandated and considers that cost pass through arrangements could also be appropriate for Ergon Energy.

The AER has not approved Ergon Energy's proposed forecast replacement capex associated with the potential rollout of energy efficient luminaires. Ergon Energy advised that no opex had been allocated to the rollout of energy efficient luminaires.[1069]

Ergon Energy proposed that cost escalators should be applied to its street lighting capex without modification.[1070] The AER's assessment of Ergon Energy's proposed material cost escalators is set out in appendix H of this draft decision. The AER

[1066] Ergon Energy, *Regulatory proposal*, July 2009, NARMCOS Data Model, confidential.
[1067] Ergon Energy, *Regulatory proposal*, July 2009, p. 462.
[1068] Local Buy, *Submission to the AER*, 27 August 2009.
[1069] Ergon Energy, response to information request AER.ERG.06.07, 27 August 2009, confidential.
[1070] Ergon Energy, *Regulatory proposal*, July 2009, p. 475.

considers that Ergon Energy should apply its respective material cost escalators to its street lighting capex consistent with appendix H. Following a request from the AER, Ergon Energy modelled its street lighting capex in accordance with the material cost escalators set out in appendix H, which results in a $1.2 million adjustment to its forecast capex.

Following its review of Ergon Energy's capex proposal the AER made the following adjustments:

- $3.3 million reduction to total street lighting capex, to exclude expenditure associated with the energy efficient street lighting rollout

- $1.2 million dollar reduction to total street lighting capex, applied across all components of forecast capex, to account for errors in the application of input cost escalators.

As a result of its analysis of the information provided by Ergon Energy, the AER is not satisfied that the proposed street lighting capex allowances reasonably reflect the capex criteria, including the capex objectives. The AER also notes that Ergon Energy is required to provide a forecast capex associated with the provision of new street lighting assets as part of its revised regulatory proposal.

The AER considers that making a $4.5 million reduction to Ergon Energy's forecast capex is likely to result in street lighting capex that reasonably reflect the capex criteria, including the capex objectives, and are the minimum adjustments necessary for this capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

Table 17.11: AER's conclusion on Ergon Energy's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed capex	2.8	3.1	3.5	4.3	5.0	18.7
Adjustments to energy efficient luminaire upgrade	0.0	–0.3	–0.5	–1.0	–1.5	–3.3
Adjustments to cost escalators	–0.0	–0.1	–0.2	–0.4	–0.5	–1.2
AER capex allowance	2.7	2.8	2.8	2.9	2.9	14.2

Source: Ergon Energy, PL880c, 24 November 2009 (confidential).
Notes: Totals may not add due to rounding.

17.6.3.3 Forecast opex

Energex

Energex stated that its forecast opex (set out in table 17.2) reflects all planned maintenance and corrective repair to street lights including street light patrols. It stated that street light assets are maintained to meet the applicable Australian standards.[1071] Energex noted that forecast opex was based on existing contract arrangements and historical trends in accordance with the mains asset management policy.[1072]

The AER has compared Energex's forecast opex against business as usual estimates extrapolated throughout the next regulatory control period on the basis of the street light asset base growth. The AER's assessment of Energex's proposed opex reflects that the maintenance and repair of street light assets as being below the 10 year trend line. In the absence of further information or concerns raised in submissions by interested parties the AER considers that Energex's proposed opex is not unreasonable, based on a continuation of business as usual conditions.

The AER's assessment of Energex's proposed material cost escalators is set out in appendix H of this draft decision, in which the AER made a number of adjustments to the material cost escalators proposed by Energex. The AER considers that Energex should apply its respective material cost escalators to its street lighting opex consistent with appendix H. Following a request from the AER, Energex modelled its street lighting opex in accordance with the material cost escalators set out in appendix H, which results in a $4.8 million adjustment to its forecast opex.

As a result of its analysis of the information provided by Energex, the AER is not satisfied that the proposed street lighting opex allowances reasonably reflect the opex criteria, including the opex objectives.

The AER considers that making a $4.8 million reduction to Energex's forecast opex is likely to result in street lighting opex that reasonably reflect the opex criteria, including the opex objectives, and are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

Table 17.12: AER's conclusion on Energex's opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed opex	12.2	12.7	13.0	13.4	13.7	65.0
Adjustments to cost escalators	–0.7	–0.9	–1.1	–1.3	–1.5	–5.4
Variance to overhead reallocation	0.2	0.2	0.2	0.1	0.2	0.8
AER opex allowance	11.8	11.9	12.1	12.3	12.4	60.4

Source: Energex, email to AER, 23 November 2009 (confidential).
Notes: Totals may not add due to rounding.
(a) This total opex adjustment includes a $0.2 million reduction relating to debt raising costs.

Ergon Energy

Ergon Energy stated that the driver of its street lighting opex in the next regulatory control period is the bulk lamp replacement program, in particular, the extension of

[1071] Energex, *Regulatory proposal*, July 2009, p. 311.
[1072] Energex, response to information request AER.EGX.04.05, 14 August 2009 confidential.

the program to include major and minor category lights and a move from a four year replacement cycle to a three year replacement cycle.[1073]

Ergon Energy provided a sound business case supporting its proposal to introduce the new bulk lamp replacement program and reduce patrol frequency during the next regulatory control period.[1074] The AER notes the following:

- the bulk lamp replacement program covers more than just lamp replacement: other maintenance issues are be included which allow for a reduced requirement for patrols and spot maintenance
- the program is also a means of replacing obsolete lamps with a standard range which will reduce inventory and subsequent maintenance costs
- the proposed patrol regime to be adopted following the rollout of the bulk lamp replacement program is a minimalistic approach
- the spot maintenance response target is 14 days
- Ergon Energy appear to have sought learning's from the experience of other DNSPs
- Ergon Energy has adopted a considered policy of maintaining a service availability consistent with Australian Standard AS/NZS 1158
- the cost comparison indicates a saving of $1.1 million (some 20 per cent) per annum in preventative and corrective maintenance.

On the basis of this information the AER considers Ergon Energy's proposed bulk lamp replacement program is prudent.

SPA Consulting stated that Ergon Energy's proposed three year bulk lamp replacement schedule for metal halide lamps is not appropriate and that a replacement cycle of between 18 months and two years is necessary since failure to replace metal halide lamps within this timeframe may lead to lamp failures and increased risk of accident and injury.[1075] Following an information request from the AER, Ergon Energy stated that it has 190 metal halide lamps within its network of which about 150 lamps are maintained by other parties and that the remaining lamps are watchman lights (which is an unregulated service). Therefore Ergon Energy did not forecast any expenditure associated with the metal halide lamps.[1076]

Ergon Energy also proposed that cost escalators should be applied to its street lighting opex without modification.[1077] The AER's assessment of Ergon Energy's proposed material cost escalators is set out in appendix H of this draft decision, in which the

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[1073] Ergon Energy, *Regulatory proposal*, July 2009, p. 467.
[1074] Ergon Energy, response to information request AER.ERG.06.08, 14 August 2009 confidential and Ergon Energy, PL789c_EE_Public Lighting Maintenance Strategy_Recommendations Paper.pdf.
[1075] LGAQ, *Submission to the AER*, 25 August 2009.
[1076] Ergon Energy, response to information request AER.ERG.25.01, 8 October 2009 confidential.
[1077] Ergon Energy, *Regulatory proposal*, July 2009, p. 475.

AER made a number of adjustments to the material cost escalators proposed by Ergon Energy. The AER considers that Ergon Energy should apply its respective material cost escalators to its street lighting opex consistent with appendix H. Following a request from the AER, Ergon Energy modelled its street lighting opex in accordance with the material cost escalators set out in appendix H, which results in a $10 million adjustment to its forecast opex.

As a result of its analysis of the information provided by Ergon Energy, the AER is not satisfied that the proposed street lighting opex allowances reasonably reflect the opex criteria, including the opex objectives.

The AER considers that making a $10 million reduction to Ergon Energy's forecast opex is likely to result in street lighting opex that reasonably reflect the opex criteria, including the opex objectives, and are the minimum adjustments necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

Table 17.13: AER's conclusion on Ergon Energy's opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed opex	14.7	14.3	14.4	14.8	15.1	73.3
Adjustments to cost escalators[a]	–1.0	–1.5	–2.2	–2.7	–3.1	–10.4
AER opex allowance	13.7	12.9	12.2	12.2	12.0	63.0

Source: Ergon Energy, PL880c, 24 November 2009 (confidential).
Notes: Totals may not add due to rounding.
(a) This total opex adjustment includes a $0.1 million increase relating to debt raising costs.

The LGAQ stated that Ergon Energy's proposed operation, repair, replacement and maintenance of street lighting assets will result in a significant increase in costs to customers.[1078] The AER's review of Ergon Energy's proposed opex concluded that an opex allowance of $63 million Ergon Energy's was appropriate.

Notwithstanding the above, the AER acknowledges that based on Ergon Energy's regulatory proposal it is not possible to evaluate the implications of this opex allowance on prices for its street lighting services. Ergon Energy noted that their indicative prices, set out in table 17.6, are not the basis on which it intends to charge for street lighting services.[1079] The AER requested that Ergon Energy provide prices for its street lighting services. The AER's consideration of these prices is set out in section 17.6.3.6 of this draft decision.

17.6.3.4 Other building block elements

This section sets out the AER's consideration of the Qld DNSPs' other building block elements: tax, depreciation, cost of capital and pass throughs.

[1078] LGAQ, *Submission to the AER*, 25 August 2009.
[1079] Ergon Energy, *Regulatory proposal*, July 2009, p. 482.

The framework and approach specified that the Qld DNSPs may propose simplifying assumptions within the limited building block approach.[1080] The Qld DNSPs' proposed treatment of tax, depreciation, cost of capital and pass through are consistent with their proposed approach for standard control services.

Estimated cost of corporate income tax

Energex stated that it calculated its tax depreciation allowance for its street lighting services on a straight line basis in accordance with the requirements of the PTRM.[1081] Ergon Energy estimated the cost of corporate income tax for street lighting services consistent with its approach for standard control services.[1082]

In developing their estimated cost of corporate income tax the AER notes that the Qld DNSPs calculated the amounts correctly using the PTRM. Further, the AER reviewed the assumed utilisation of imputation credits (gamma) in chapter 9 of this draft decision. The AER's assessment concluded that the Qld DNSPs had not demonstrated that the gamma of 0.65 set out in the AER's *Statement of Regulatory Intent* (SORI) is inappropriate. The Qld DNSPs' have applied gamma consistent with the SORI for their respective street lighting services. The AER is satisfied that the allowances for corporate income tax for street lighting services, as set out in tables 17.14 and 17.15, have been determined correctly.

Depreciation

The AER assessed the Qld DNSPs' proposed annual allowances for regulatory depreciation and its effect on the opening street lighting asset base as at 1 July 2010 in section 17.6.2 of this draft decision.

The Qld DNSPs' proposed to calculate regulatory depreciation for alternative control (street lighting) services consistent with the approach for standard control services.[1083] The AER notes that this is consistent with the framework and approach and considers this appropriate.[1084]

Chapter 10 of this draft decision sets out the AER's assessment of the Qld DNSPs' proposed asset lives used to calculate their depreciation schedules for the next regulatory control period. In that chapter, the AER concluded that Energex's proposed remaining lives were consistent with the requirements of clause 6.5.5 of the NER. The depreciation allowance for Energex, set out in table 17.14, reflects its proposed remaining life of 10.8 years for its non–contributed street lighting assets.

The AER's review of the remaining lives identified an error in the way Ergon Energy had calculated these lives for all asset classes. Specifically, it had divided real depreciation figures by a nominal closing balance. The AER required Ergon Energy to correct this error in its modelling. The correct remaining life for Ergon Energy's

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[1080] AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008, p. 41.

[1081] Energex, *Regulatory proposal*, July 2009, p. 314.

[1082] Ergon Energy, *Regulatory proposal*, July 2009, p. 479.

[1083] Energex, *Regulatory proposal*, July 2009, pp. 313–314; and Ergon Energy, *Regulatory proposal*, July 2009, p. 478.

[1084] AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008.

street lighting asset class is 7.63 years rather than the 8.9 years proposed. The depreciation allowance for Ergon Energy set out in table 17.15 reflects this corrected remaining life.

Cost of capital

The Qld DNSPs' proposed to apply the post–tax nominal weighted average cost of capital (WACC) 9.49 per cent proposed for standard control services to street lighting services.[1085] The AER's assessment of the Qld DNSPs' proposed WACC is set out in chapter 11 of this draft decision. In accordance with that assessment and the framework and approach the AER has applied a 10.06 per cent WACC to street lighting services. This WACC has been used to calculate each of the Qld DNSPs' return on capital for street lighting services, as set out table 17.14 and 17.15.

Adjustments for non–system revenue allocation

Energex stated that an adjustment to its street lighting revenue is required to recognise revenue associated with non–system assets used in the provision of street lighting services.[1086] Energex determined the revenue attributable to alternative control services for non–system assets based on the forecast expenditure for alternative control services as a proportion of forecast total expenditure (for all services), where total expenditure includes capex and opex.[1087]

Following a request from the AER, Energex modelled its non–system revenue allocation between standard control services and alternative control services in accordance with its stated approach and determined a $10 million adjustment to its limited building block revenue requirement, as set out in table 17.14.[1088]

The AER notes that Energex's non–system asset revenue adjustment results in a reduction to the standard control services revenue requirements and that, consequently, there is no over recovery of revenues. The AER considers that the inclusion of revenue associated with the use of non–system assets used in the provision of street lighting services is reasonable since Energex's street lighting asset base does not include any non–system assets. On that basis, the AER accepts the inclusion of an adjustment to Energex's street lighting revenue for the non–system assets used in the provision of street lighting services.

Pass through arrangements

The Qld DNSPs' proposed that the pass through provisions for the defined events and nominated events should be applied to both standard control services and alternative control services (including street lighting).[1089] The AER's assessment of the Qld DNSPs' proposed pass through events is set out in chapter 15 of this draft decision. The AER considers it is appropriate to apply pass through provisions to alternative

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[1085] Energex, *Regulatory proposal*, July 2009, p. 313; Ergon Energy, *Regulatory proposal*, July 2009, p. 478.
[1086] Energex, *Regulatory proposal*, July 2009, p. 315.
[1087] Energex, *Regulatory proposal*, July 2009, p. 270.
[1088] Energex, response to information request AER.EGX.36, 23 November 2009 confidential.
[1089] Energex, *Regulatory proposal*, July 2009, p. 318; and Ergon Energy, *Regulatory proposal*, July 2009, pp. 475–476.

control services.[1090] Therefore, the events accepted in chapter 15 of this draft decision will apply to all direct control services, including street lighting services.

17.6.3.5 Limited building block revenue requirement

Clause 6.4.3(a) of the NER sets out the building blocks that form the annual revenue requirement. The AER's limited building block approach for street lighting services incorporates the following building blocks:[1091]

- an indexed street light asset base
- return on capital
- depreciation
- forecast opex
- estimated cost of corporate income tax.

Energex

The AER has determined the opening value of Energex's street lighting services asset base as at 1 July 2010 to be $96 million. The AER has rolled forward Energex's RAB in the next regulatory control period using the PTRM as shown in tables 17.7 and 17.8.

The AER accepts Energex's proposed depreciation allowance. This is set out in table 17.14.

The AER has determined a 10.06 per cent WACC is to be used to calculate Energex's return on capital for street lighting services.

The AER has determined a forecast opex allowance for Energex of $60 million ($2009–10) for the next regulatory control period.

The AER has determined Energex has correctly calculated the allowance for corporate income tax for its street lighting services.

The AER accepts the inclusion of a $10 million adjustment to Energex's street lighting revenue representing the non–system assets used in the provision of street lighting services.

Following a request from the AER, Energex modelled its limited building block revenue requirement for street lighting services in accordance with this draft decision. Table 17.14 sets out all the building block elements and X factors for Energex.

[1090] AER, *Final framework and approach paper: Application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 56.

[1091] Energex also proposed to recover the return on capital for non–system assets used in the provision of street lighting services.

Table 17.14: Energex approved annual revenues and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.7	7.6	8.6	9.6	10.7
Return on capital	9.7	10.9	12.0	13.2	14.4
Operating expenditure	12.1	12.6	13.0	13.6	14.0
Tax allowance	2.3	2.3	2.3	2.3	2.4
Adjustment for non–system revenue allocation	1.7	1.9	2.1	2.3	2.2
Annual revenue requirement[a]	32.5	35.2	38.1	41.1	43.7
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[b] (%)	24.19	–3.65	–3.65	–3.65	–3.65
Smoothed annual revenue requirement	33.6	35.7	37.9	40.2	42.7

Source: Energex, response to information request AER.EGX.37, 24 November 2009.
Note: Totals may not add due to rounding.
(a) This is the unsmoothed annual revenue requirement.
(b) Negative values for X indicate real price increases under the CPI–X formula.

Ergon Energy

The AER has determined the opening value of Ergon Energy's street lighting services asset base as at 1 July 2010 to be $53 million.

The AER determined that an adjustment was required to Ergon Energy's remaining life for its street lighting asset class.

The AER determined that a 10.06 per cent WACC is to be used to calculate Ergon Energy's return on capital for street lighting services.

The AER has determined a forecast opex allowance for Ergon Energy of $63 million ($2009–10) for the next regulatory control period.

The AER determined that Ergon Energy has correctly calculated the allowance for corporate income tax for its street lighting services.

Following a request from the AER, Ergon Energy modelled its limited building block revenue requirement for street lighting services in accordance with this draft decision. Table 17.15 sets out the building block elements and X factors for Ergon Energy.

Table 17.15: Ergon Energy revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	5.4	5.1	4.8	4.4	4.0
Return on capital	5.9	6.2	6.7	7.1	7.6
Operating expenditure	14.1	13.5	13.2	13.4	13.6
Tax allowance	0.7	0.7	0.7	0.8	0.8
Annual revenue requirement[a]	26.0	25.5	25.3	25.6	25.9
Forecast CPI (per cent)	2.45	2.45	2.45	2.45	2.45
X factors[b] (per cent)	–64.13	2.00	2.00	2.00	2.00

Source: Ergon Energy, PLPTRM Data Model, 24 November2009, confidential.
Notes: Totals may not add due to rounding.
(a) This is the unsmoothed annual revenue requirement
(b) Negative values for X indicate real price increases under the CPI–X formula.

17.6.3.6 Prices and price path

The AER's consideration of the Qld DNSPs' proposed limited building block approaches results in the revenue requirements set out in tables 17.14 and 17.15.

The AER's framework and approach the AER stated that it would establish the price for street lighting services in the first regulatory year of the next regulatory control period and develop a price path for these services in the remaining regulatory years of the next regulatory control period.

Energex

Energex developed prices for the first regulatory year of the next regulatory control period by allocating revenue based on the relative revenue proportion of major and minor category street lights and the applicable asset funding arrangement (non–contributed and contributed), as set out in table 17.3. Street lights are allocated into either the major and minor category according to luminaire type and size, and non–contributed and contributed (based on the funding arrangement).[1092]

Local Buy noted there was a large disparity in Energex's proposed maintenance costs where major contributed lights are more than double that of minor contributed street lights. It considered that this difference was unreasonable. It also stated that the future street lighting prices proposed by Energex do not appear to account for the identified decrease in capex requirements from the current to the next regulatory control period and that the prices for non–contributed minor lights would increase by 34 per cent in 2010–11.[1093]

[1092] Energex, *Regulatory proposal*, July 2009, p. 308.
[1093] Local Buy, *Submission to the AER*, 27 August 2009.

The AER has reviewed additional information provided by Energex on how the revenue proportions and opex prices were determined.[1094] Energex apportioned the revenue requirement for the recovery of opex to major and minor street lighting services (based on its revenue proportions) and the same proportions were then applied to non–contributed and contributed categories.[1095]

The methodology used by Energex to calculate the revenue ratio to recover opex (and return on and return of capital) was based on the number of street lights (as at 29 April 2009) in each category multiplied by the capital value estimate of the installation cost.[1096] Thereafter, the resulting total value of the installed street lights was apportioned to major and minor categories based on the number of street lights in each category. Table 17.16 outlines the number and type of Energex's installed street lights.[1097]

Table 17.16: Energex installed street lights as at 29 April 2009

Category	Steel	Wood	Total
Major	41 564	34 987	76 551
Minor	97 054	103 275	200 329
Total	138 618	138 262	276 880

Source: Energex, response to information request AER.EGX.04.04, 26 August 2009, confidential.

The AER considers Energex's methodology is reasonable to develop the revenue ratio to street lighting categories in order to appropriately recover the revenue requirement from each street lighting category.

The AER accepts that there is disparity between the maintenance costs for major and minor contributed street lights. However, the AER does not consider this to be unreasonable since the method employed by Energex to derive the prices for major and minor contributed street lights is appropriate.

Following a request from the AER, Energex modelled its limited building block revenue requirement for street lighting services accounting for the changes made by the AER and determined the prices for non–contributed and contributed major and minor street lights, which are set out in table 17.14. These prices are set to recover the smoothed revenue requirement as per the street lighting PTRM approved by the AER.

Energex's proposed street lighting prices, set out in table 17.3, show an increase in the price for minor non–contributed customers and a decrease in prices for the remaining street light categories (major non–contributed, minor contributed and major

1094 Energex, response to information request AER.EGX.04.09, 14 August 2009 confidential.

1095 Energex, *Regulatory proposal*, July 2009, pp. 308–309; and Energex, response to information request AER.EGX.04.09, 14 August 2009 confidential.

1096 Energex used the same methodology to apportion the revenue requirement for the recovery of return on and return of capital.

1097 The AER granted confidentiality to Energex's installations costs and capital value estimates.

contributed). The prices can be attributed to the change in the revenue ratio used to apportion the recovery of the revenues from each street lighting category.

Table 17.17: Energex street lighting prices (dollars per light per day, GST exclusive)

	First year price path (%)	2010–11	2011–12	2012–13	2013–14	2014–15
Major non–contributed	–9.64	0.86	0.90	0.94	0.98	1.02
Major contributed	49.88	0.37	0.38	0.40	0.42	0.43
Minor non–contributed	–73.30	0.25	0.26	0.28	0.29	0.30
Minor contributed	–32.28	0.11	0.11	0.12	0.12	0.13
Price path (%)		n/a	4.38	4.38	4.38	4.38

Source: Energex, response to information request AER.EGX.37, 24 November 2009.
Note: A positive price path indicates a price increase.

Ergon Energy

Ergon Energy provided the indicative prices set out in table 17.6 for the provision of its category 2 street light services in the next regulatory control period. However, it stated that these prices are not the basis on which it intends to charge for these services. Ergon Energy stated that its indicative prices for street lighting services are an expression of its proposed annual revenue requirement per street light.[1098]

The LGAQ noted concern with Ergon Energy's proposed 66 per cent increase in costs from 2009–10 to 2010–11. Based on the figures in Ergon Energy's regulatory proposal, the LGAQ considered that there is the potential for a 100 per cent increase in street lighting costs to councils within Ergon Energy's service area.[1099]

Local Buy stated that Ergon Energy's regulatory proposal lacks definite cost allocations for the various components in the next regulatory control period and accordingly it could not provide any definitive comments on the impacts of the regulatory proposal.[1100]

The AER requested that Ergon Energy model its revenue requirement as per the changes made by the AER in this draft decision and develop street lighting prices that it intends to charge its customers in the next regulatory control period, which are set out in table 17.18. These prices are set to recover the revenue requirement as per the street lighting PTRM approved by the AER.

Given that Ergon Energy noted that their indicative prices, set out in its regulatory proposal and table 17.6, are not the basis on which it intends to charge for street lighting services, it was not possible for the AER to evaluate the price outcomes of

[1098] Ergon Energy, *Regulatory proposal*, July 2009, p. 482.
[1099] LGAQ, *Submission to the AER*, 25 August 2009.
[1100] Local Buy, *Submission to the AER*, 27 August 2009.

Ergon Energy proposed limited building block revenue requirement. Following a request from the AER, Ergon Energy provided modelling that demonstrated the derivation of the prices for street lighting services set out in table 17.18.[1101] The AER will review the underlying methodology used to derive these prices as part of its final decision.

Table 17.18: Ergon Energy street lighting prices (dollars per light per day, GST exclusive)

	2010–11	2011–12	2012–13	2013–14	2014–15
East – Major	0.42	0.41	0.40	0.40	0.40
Price path (%)		–3.05	–2.15	–0.02	–0.22
East – Minor	0.63	0.61	0.60	0.60	0.60
Price path (%)		–3.05	–2.15	–0.02	–0.22
West – Major	0.67	0.66	0.65	0.66	0.67
Price path (%)		–1.86	–0.95	1.21	1.01
West – Minor	0.65	0.64	0.64	0.64	0.65
Price path (%)		–1.87	–0.96	1.20	1.00
Mt Isa – Major	0.41	0.40	0.39	0.39	0.40
Price path (%)		–2.17	–1.26	0.90	0.70
Mt Isa – Minor	0.40	0.39	0.39	0.39	0.40
Price path (%)		–2.18	–1.27	0.88	0.68

Source: Ergon Energy, *Regulatory proposal*, July 2009, PL878c, 24 November 2009, confidential.

Note: A positive price path indicates a price increase.
Ergon Energy did not provided an indication of the percentage change from 2009–10 to 2010–11 for each street lighting service in the first regulatory year of the next regulatory control period.

17.6.4 Compliance with the price cap

Energex did not specifically address how it would demonstrate compliance with the price cap control mechanism applicable to its street lighting services.

Ergon Energy stated that, as part of its pricing proposal, it would submit capped prices applicable to its street lighting services in the first regulatory year of the next regulatory control period and a price path for the remaining regulatory years.[1102]

[1101] Ergon Energy, *Regulatory proposal*, July 2009, PL878c, 24 November 2009, confidential.
[1102] Ergon Energy, *Regulatory proposal*, July 2009, p. 481.

Clause 6.12.1(13) of the NER requires that the AER's distribution determination includes a decision on how compliance with the control mechanism for street lighting services is to be demonstrated.

Under the price cap control mechanism the price for each street lighting service contained in this draft decision is the maximum price the Qld DNSP can charge for that service in a regulatory year. Compliance with the control mechanism is to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the proposed prices for each street lighting service in the relevant regulatory year.

The proposed prices must be consistent with this draft decision for the relevant regulatory year. The pricing proposal should also include the revenues collected from the provision of each service in the preceding regulatory year.

17.7 AER conclusion

The approved revenue requirements for each of Qld DNSPs' street lighting service are set out in tables 17.14 and 17.15. The AER requested the Qld DNSPs' calculate prices for each of their respective street lighting services to recover the approved revenue requirements. The results of this process are set out in tables 17.17 and 17.18.

In 2010–11the price for each of the Qld DNSPs' respective street lighting services, set out in tables 17.17 and 17.18, represents the capped price for each service to be provided by the Qld DNSPs'. The price paths, also set out in tables 17.17 and 17.18, establishes the prices for each street lighting service to be provided by the Qld DNSPs in the remaining regulatory years of the next regulatory control period.

Compliance with the price cap control mechanism is to be demonstrated by each Qld DNSP providing, as part of its pricing proposal, the capped price for each street lighting service in the relevant regulatory year consistent with this draft decision.

The AER's approved prices represent the maximum price to be charged for each street lighting service in each regulatory year of the next regulatory control period.

17.8 AER draft decision

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Energex's street lighting services is:

- caps on the prices of individual services, in the first regulatory year of the next regulatory control period (as set out in table 17.17 of this draft decision)
- price paths, as set out in table 17.17 of this draft decision, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Energex's compliance with the control mechanisms for street lighting services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 17.6.4 of this draft decision.

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Ergon Energy's street lighting services is:

- caps on the prices of individual services in the first regulatory year of the next regulatory control period (as set out in table 17.18 of this draft decision)
- price paths, as set out in table 17.18 of this draft decision, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Ergon Energy's compliance with the control mechanism for street lighting services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 17.6.4 of this draft decision.

18 Alternative control – quoted and fee based services

18.1 Introduction

Clause 6.2.2(a) of the NER divides direct control services into standard control services and alternative control services.

This chapter sets out the AER's consideration of the Qld DNSPs' alternative control (quoted and fee based) services control mechanism and how compliance with that mechanism is to be demonstrated by the Qld DNSPs in the next regulatory control period.

Classification of the Qld DNSPs' quoted and fee based services is set out in chapter 2 of this draft decision.

18.2 Regulatory requirements

Clause 6.8.1 of the NER requires the AER to publish a framework and approach in anticipation of every distribution determination, which amongst other things includes the control mechanisms to apply to direct control services.

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. 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.

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.

18.3 AER framework and approach

The framework and approach stated the AER would apply separate price cap control mechanisms to the Qld DNSPs' quoted and fee based services in the next regulatory control period.[1103] The AER stated that a formula based (non-building block) approach would be used to establish the efficient costs of providing quoted and fee based services in the first regulatory year of the next regulatory control period, and that price paths would be established for the remaining regulatory years of the next regulatory control period.

[1103] AER, *Final Decision, Framework and approach paper: Classification of services and control mechanisms*, August 2008, pp. 43–44.

18.4 Queensland DNSP regulatory proposals

The Qld DNSPs applied the control mechanism set out in the framework and approach.

Energex

Energex proposed to calculate the price for quoted and fee based services using the following formula:[1104]

$$\text{Price} = \text{Labour} + \text{Contractor services} + \text{Materials} + \text{Capital allowance} + \text{Profit margin} + \text{GST}$$

Where:

Labour (including on costs and overheads)—consists of all labour costs directly incurred in the provision of the service, labour on costs, fleet on costs and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service.

Contractor services (including overheads)—reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer.

Materials (including overheads)—reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads.

Capital allowance—represents a return on and return of capital for non-system assets (for example vehicles, IT and tools) used in the provision of the service.

Profit margin—reflects a margin on direct costs (labour, contractor services and materials) to ensure competitive neutrality prevails in the service market and ensure an appropriate return is earned commensurate with the level of risk associated with the use of all assets in providing and delivering the service.

GST—represents the goods and services tax (GST) component of the service charge.

Energex allocated on costs to its direct costs (labour and materials) on a dollar per dollar of expenditure basis.[1105] It stated that overheads relate to the indirect costs incurred in the provision of quoted and fee based services and have been applied according to its approved cost allocation methodology (CAM).[1106]

Energex provided worked examples of each of its quoted and fee based services to be offered in the next regulatory control period.[1107] The prices it proposed to apply to its

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[1104] Energex, *Regulatory proposal*, July 2009, p. 324.
[1105] Energex, *Regulatory proposal*, July 2009, appendix 22.2, p. 2.
[1106] Energex, *Regulatory proposal*, July 2009, appendix 22.2, p. 2.
[1107] Energex, *Regulatory proposal*, July 2009, appendix 22.5; and Energex, response to information request AER.EGX.25.05, 9 October 2009, confidential.

illustrative quoted service configurations in the next regulatory control period are set out in appendix N of this draft decision. No specific price path for quoted services was provided. Energex's proposed price path and prices for its fee based services in the next regulatory control period are set out in appendix P of this draft decision.

Ergon Energy

Ergon Energy proposed to calculate the price (P_i) for quoted and fee based services using the following formula:[1108]

$$P_i = L_i + M_i + OC_i + CA_i + GST_i$$

where:

L_i is the cost of labour (internal and external) involved in the delivery of the service (inclusive of on costs and overheads), calculated as the product of an hourly rate and the time spent by the personnel. This amount includes both travel time and time spent delivering the service.

M_i is the cost of non-capitalised materials expensed in the delivery of the service (inclusive of overheads).

OC_i are other one-off costs (inclusive of overheads) relating to the delivery of the service, including hire or supply of additional equipment, assets or labour and contingency costs.

GST_i the goods and services tax component of the service charge.

CA_i reflects the return on and return of non-system capital employed in the delivery of the service (for example, trucks and IT systems), which is calculated using the below formula:

$$CA_i = CNS_i + CV_i$$

where:

CNS_i reflects the return on and of non-system assets (excluding vehicles) allocated to the delivery of the service. This charge will be applied as a percentage of the sum of the total Labour, Materials and Other Costs based on historical trends.

CV_i reflects the return on and return of vehicles used in the delivery of the quoted service.

Ergon Energy stated that the cost of labour includes the labour rates contained in the Ergon Energy Union Collective Agreement 2008 and labour on costs consist of costs associated with pay roll tax, superannuation and other employee entitlements.

In determining the cost of materials, Ergon Energy stated that it would apply either its internal transmission and distribution services estimating tool, its customer initiated

[1108] Ergon Energy, *Regulatory proposal*, July 2009, p. 490.

capital works price book, or its Ellipse system—depending on the specific materials required to deliver an individual service.[1109] It also noted that it would allocate overheads to labour, materials and other costs consistent with its approved CAM.[1110]

Ergon Energy provided worked examples of its quoted and fee based services that it plans to offer in the next regulatory control period.[1111] The prices it proposed to apply to its illustrative quoted service configurations in the next regulatory control period are set out in appendix N of this draft decision. No specific price path for quoted services was provided. Ergon Energy's proposed price path and prices to apply to fee based services in the next regulatory control period are set out in appendix P of this draft decision.

18.5 Submissions

No submissions were received commenting on the Qld DNSPs' quoted or fee based services.

18.6 Issues and AER consideration

18.6.1 Control mechanism

The AER stated in the framework and approach paper that it would apply a formula based approach (a non-building block approach) to determine the efficient costs of providing quoted and fee based services. The approach involves a price cap control mechanism in the first regulatory year of the next regulatory control period and a price path for the remaining regulatory years of that period.[1112] A price cap form of control is currently applied to these services by the QCA.[1113]

Quoted services

The AER recognises that the scope of the work for each quoted service is not known prior to the service being undertaken and therefore these services are provided on a price on application basis. Hence it is not possible to cap the price for individual quoted services as the scope of work, and therefore the cost, for each individual quoted service is not known prior to the service being provided. The Qld DNSPs' proposed formulas account for this variability.

Given the nature of quoted services, the application of the price cap control mechanism in this instance requires the individual formula component inputs to be capped. This approach allows the total price for an individual quoted service to vary according to the size, scale and scope of the individual service being undertaken. For

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1109 Ellipse is a cost estimation tool.
1110 Ergon Energy, *Regulatory proposal*, July 2009, p. 491.
1111 Ergon Energy, *Regulatory proposal*, July 2009, AR482c_EE_All Quoted Services_Summary_28May09.xls, confidential.
1112 AER, *Final framework and approach paper: Classification of services and control mechanisms,* August 2008, pp. 43–44.
1113 The QCA approves the application of the formula for quoted services and approves the prices for fee based services on an annual basis as part of its pricing principles statement. The Qld DNSPs set out a formula identifying all the variables for each quoted service and what variables are subject to change.

subsequent regulatory years, the AER has established a price path for each component of the formula to be used to derive the price of individual quoted services.

Appendix O (confidential) of this draft decision sets out illustrative worked examples of each quoted service to be offered by the Qld DNSPs in the next regulatory control period.

Fee based services

The formula based price cap control mechanism is also to be applied to derive the price for fee based services. The capped price is calculated using the individual formula component inputs used in the provision of each service. Given that the size, scale and scope of each fee based service is known in advance of each individual service being requested, the AER has been able to cap the first regulatory year's price. The AER has established a price path for each fee based service in the remaining regulatory years of the next regulatory control period using the approved price path for each formula component.

The AER has determined the efficient costs for fee based services in the next regulatory control period, which are set out in appendix P of this draft decision.

18.6.2 Assessment of control mechanism formula components

The AER has established a price path for each formula component to be used to derive the price of individual quoted and fee based services in each year of the next regulatory control period.

18.6.2.1 Labour rates

The Qld DNSPs proposed base labour rates for each employee classification required to perform quoted and fee based services, and a price path (labour cost escalators) to apply to these base labour rates in the next regulatory control period.

Energex proposed a separate formula component representing contractor services, that is, its external labour. Ergon Energy included a contractor category in its employee classifications.

The AER has assessed both the internal and external labour rates of the Qld DNSPs. The labour formula component represents the number of hours required to provide an individual quoted or fee based service multiplied by the applicable hourly rate for each employee classification. The AER reviewed the efficiency of the Qld DNSPs' employee classification base labour rates and applied an appropriate escalator to set a capped rate for the first regulatory year of the next regulatory control period.[1114] The AER then established the price path for each employee classification labour rate using the labour cost escalators applied to standard control services.

[1114] Ergon Energy's labour component of its quoted service illustrative configurations does not explicitly disaggregate labour component into employee classifications, rather labour is expressed at an aggregate level in the price cap formula.

The Qld DNSPs also proposed that on costs and overheads be applied to their respective internal and external base labour rates. The AER's assessment of on costs and overheads is set out in section 18.6.2.4 of this draft decision.

First regulatory year rates—internal labour

Energex

Energex used 2008–09 base labour rates for each employee classification required to provide quoted and fee based services to develop its first regulatory year internal labour rate.[1115]

Energex developed a model to derive 2008–09 prices for quoted services which included a base labour rate input. The AER understands that this model, incorporating this base labour rate, was submitted to the QCA as part of Energex's proposed 2008–09 prices for excluded distribution services and that the QCA accepted these prices. The AER considers the use of the 2008–09 base labour rate adopted as part of the QCA's regulated prices is a reasonable base rate from which to derive labour rates to be applied in the formula.

Energex's proposed prices for the next regulatory control period differ from its 2008–09 approach as its proposed formula used five employee classifications whereas previously it used only one employee classification. The AER accepts that a single employee classification is insufficient to derive prices for all the quoted services. After assessing the composition of Energex's illustrative quoted service examples the AER is satisfied that all employee classifications are applied and appropriately allocated to the type of skills required to undertake each individual service. For this draft decision the AER will apply all five employee classifications to derive prices for all quoted services based on Energex's 2008–09 base labour rates.[1116]

Energex developed its proposed fee based services prices using only its customer connections employee classification. These rates were determined based on the forecast total labour costs and hours incurred in the provision of fee based services in 2008–09 and then escalated by Energex's proposed labour cost escalator.[1117] The AER considers such an approach is reasonable, as it reflects the costs incurred in the provision of fee based services. However, the AER recognises that the actual values were not available at the time Energex prepared its regulatory proposal and accordingly requires Energex to provide the actual total costs and hours incurred in 2008–09 as part of its revised regulatory proposal. These actual total costs and hours are required to derive a base labour rate for Energex's customer connections category employee classification as part of the AER's final distribution determination.[1118]

[1115] Energex, response to information request AER.EGX.05.10, 27 August 2009, confidential; Energex, response to information request AER.EGX.25.05, 9 October 2009, confidential; and Energex, *Regulatory proposal*, July 2009, pp. 176–177.

[1116] Energex's electrical system design advisors, technical / service persons and power workers employee classifications have a business hour base labour rate and an after hours base labour rate.

[1117] Energex, response to information request AER.EGX.05.10, 27 August 2009, confidential.

[1118] Energex's customer connection category employee classification has a business hour base labour rate and an after hours base labour rate

The AER will use Energex's 2008–09 base labour rates as the basis to develop capped labour prices for quoted and fee based services in the next regulatory control period.

Ergon Energy

Ergon Energy submitted 2008–09 base labour rates to be applied in the calculation of prices for quoted and fee based services to apply in the next regulatory control period and were sourced from its finance systems.[1119]

Ergon Energy developed models that derive the 2008–09 prices for excluded distribution services for which its 2008–09 base labour rates are an input. The AER understands that these models, incorporating the 2008–09 base labour rates, were submitted to the QCA for approval.

The AER has identified that the 2008–09 base labour rates set out in Ergon Energy's regulatory proposal are not consistent with the 2008–09 base labour rates accepted by the QCA. Therefore, the AER has not accepted the base labour rates Ergon Energy submitted as part of its regulatory proposal as there is no tangible link between the proposed base labour rates and the prices for quoted and fee based services previously accepted by the QCA. The AER notes that the QCA regarded the 2008–09 prices as satisfying the regulatory requirements at that time, therefore, the AER has adopted these 2008–09 base labour rates for determining the prices of quoted and fee based services in the next regulatory control period.[1120]

The AER approved 2008–09 base labour rates consist of 11 employee classifications. The AER notes that Ergon Energy has included three additional employee classifications (contractor, system operator and trainee) to those approved by the QCA in 2008–09. Ergon Energy has not supplied supporting material justifying the introduction of these new employee classifications, or demonstrated how 2008–09 base labour rates reflect efficient labour costs.

The AER has not been able to review Ergon Energy's allocation of its employee classifications in its illustrative quoted service examples since labour was allocated at an aggregate level in each example. For this reason the AER has not included these new employee classifications in deriving first regulatory year prices for quoted and fee based services. The AER requires Ergon Energy to provide information that demonstrates how each employee classification has been applied in its illustrative quoted service examples as part of its revised regulatory proposal, which it will assess as part of the AER's final distribution determination.

However, the AER was able to review Ergon Energy's allocation of employee classifications to its fee based services and considers that approach appropriate. The AER notes that Ergon Energy's fee based services do not include the three newly introduced employee classifications.

1119 Ergon Energy, *Regulatory proposal*, July 2009, p. 336 and AR443c_EE_Fixed Fee Services_Indicative Prices Calculation_2.xls, confidential; and Ergon Energy, response to information request AER.ERG.24.04, 16 October 2009, confidential.

1120 Ergon Energy's employee classifications include business hour base rates and an after hours base rates.

The AER applied the 2008–09 base labour rates for the employee classifications accepted by the QCA in 2008–09 as the basis to develop capped labour prices for quoted and fee based services in the next regulatory control period.

First regulatory year rates—external labour

Energex

Energex proposed a separate formula component representing its contractor services. This formula component applies the rates under existing contracts that were established through competitive tender processes. It stated that its contractor rates include all costs (excluding overheads) associated with the provision of the service.[1121]

According to its illustrative quoted service examples, Energex employed contractor services in the provision of three of its 13 quoted services. The contractor rates used are based on 2008–09 costs escalated to the relevant regulatory year using the standard control services labour cost escalators. The AER is satisfied that these 2008–09 base costs provide a suitable basis from which to develop contractor services for quoted services in the next regulatory control period.

Energex employs contractor services in all but two of its fee based services and the proposed prices for its fee based services are a weighted price according to the proportion of each service provided by Energex and its contractors. Energex appears to be achieving productivity and efficiency gains through the use of contractors in the provision of fee based services, and these gains are reflected in its proposed prices for these services.

The AER considers it efficient to include Energex's contractor services formula component into the formula to be used to derive the prices of quoted and fee based services in the next regulatory control period. The AER will therefore use Energex's 2008–09 contractor rates as the basis to develop capped contractor labour prices in the next regulatory control period.

Ergon Energy

Ergon Energy's proposed formula does not include a separate component for contractor services. As noted above, Ergon Energy's regulatory proposal contains three additional employee classifications to those accepted by the QCA in 2008–09. One of these newly introduced employee classifications is contractors. In principle the AER supports the approach that Ergon Energy has used but does not consider there is sufficient information to justify the inclusion of these base labour rates at the time of this draft decision. The AER therefore requires Ergon Energy to provide further information to support the inclusion of its contractor employee classification's base rate as part of its revised regulatory proposal.

[1121] Energex, *Regulatory proposal*, July 2009, appendix 22.2, p. 2.

The AER notes that based on information provided by Ergon Energy it does not appear to utilise contractors in the provision of its fee based services now or during the next regulatory control period.[1122]

Price path

The Qld DNSPs proposed that their labour cost escalators for standard control services were also appropriate to apply to alternative control services, which are set out in table 18.1.[1123]

Table 18.1: Qld DNSPs' proposed nominal labour cost escalators for quoted and fee based services (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Energex	5.50	5.50	5.50	5.50	5.50	5.50
Ergon Energy	5.11	4.42	4.50	4.50	4.50	4.50

Source: Energex, response to information request AER.EGX.05.11, 27 August 2009 (confidential); and Ergon Energy, response to information request AER.ERG.24.04, 19 October 2009, confidential.

The AER's assessment of the Qld DNSPs' proposed labour cost escalators is contained in chapter 8 of this draft decision. The AER considers it appropriate to apply its labour cost escalators to the Qld DNSPs base labour rates and contractor rates to establish a capped price for each employee classification in the first regulatory year of the next regulatory control period and to establish a price path for the remaining regulatory years of that period.

The AER does not have sufficient information to allow it to include Ergon Energy's contractor employee classifications as part of this draft decision. If Ergon Energy provides information that demonstrates the appropriateness of this employee classification, the AER will determine the appropriate labour cost escalator as part of its final distribution determination.

The AER will apply the labour cost escalators set out in table 18.2 to the Qld DNSPs' 2008–09 base labour rates and Energex's contractor rates in the next regulatory control period. These labour cost escalators are consistent with those applied to the Qld DNSPs standard control services. Tables O.1, O.2 and O.3 of appendix O (confidential) of this draft decision set out the Qld DNSPs' base labour rates for each employee classification to apply to quoted and fee based services in the next regulatory control period escalated using the AER's labour cost escalators.

[1122] Ergon Energy, *Regulatory proposal*, July 2009, AR443c_EE_Fixed Fee Services_Indicative Prices Calculation_2.xls and AR478c_EE_Fixed Fee Prices_Current Period_7May09.xls, confidential.

[1123] Energex, response to information request AER.EGX.05.10, 27 August 2009 , confidential; Ergon Energy, response to information request AER.ERG.24.04, 16 October 2009, confidential.

Table 18.2: AER nominal price path for the Qld DNSPs labour formula components (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Energex						
Labour	5.33	2.70	3.08	3.73	4.09	4.08
Contractor services	4.17	2.14	3.10	3.70	4.08	4.07
Ergon Energy						
Labour	4.67	3.06	3.48	3.78	4.30	4.48

Notes: These nominal labour cost escalators are the AER's approved real labour cost escalators inflated by the AER's approved forecast inflation rate.

18.6.2.2 Materials

The materials component is not used in the provision of the Qld DNSPs' fee based services.

First regulatory year rates

The Qld DNSPs submitted that the materials component of the formula reflects the costs of materials used in the provision of quoted services.[1124]

The Qld DNSPs did not provide a complete list of the materials that could be used in this component. Ergon Energy stated that it was not practical to do so in light of the number of potential materials that could be used in the provision of these services.[1125]

The Qld DNSPs provided details of their capex planning and governance processes that underpin the provision of their electricity distribution services. The AER assessed the Qld DNSPs' capital governance frameworks in chapter 7 of this draft decision and considered that Energex's processes are consistent with the achievement of the capex objectives and that Ergon Energy's capex governance framework provides adequate assurance that investment decisions are likely to be efficient.

The AER is aware that the same processes that underpin the provision of standard control services also underpin the provision of alternative control services. Having found that these systems are robust in relation to standard control services, the AER considers it reasonable to extend this conclusion to alternative control services.

The AER is satisfied that the Qld DNSPs' capital governance frameworks provide a level of assurance that the Qld DNSPs procure and manage their materials efficiently. The AER therefore considers the cost of materials used to derive the price of quoted services in the first regulatory year of the next regulatory control period are reasonable.

[1124] Energex, *Regulatory proposal*, July 2009, p. 324; and Ergon Energy, *Regulatory proposal*, July 2009, p. 490.

[1125] Ergon Energy, response to information request AER.ERG.24.07, 19 October 2009, confidential.

Price path

The Qld DNSPs' illustrative quoted service examples escalate their 2009–10 materials cost in each year of the next regulatory control period using the rates set out in table 18.3.[1126] However, the AER notes that Ergon Energy's illustrative quoted service examples for large customer connections do not align with its proposed material cost escalators.

Table 18.3: Qld DNSPs' proposed nominal material cost escalators for quoted services (per cent)

	2010–11	2011–12	2012–13	2013–14	2014–15
Energex	2.45	2.45	2.45	2.45	2.45
Ergon Energy	5.11	3.70	4.10	3.60	3.20

Source: Energex, response to information request AER.EGX.05.11, 27 August 2009, confidential; and Ergon Energy, response to information request AER.ERG.24.04, 19 October 2009, confidential.

To establish a price path for the Qld DNSPs' base labour rates the AER considered it appropriate to apply the labour cost escalators that it applied to the Qld DNSPs respective standard control services. The AER considers it appropriate to apply the same approach to material cost escalators.

The AER's assessment of the Qld DNSPs proposed materials cost escalators is set out in appendix H of this draft decision. The AER considers the Qld DNSPs should apply their respective material cost escalators to their quoted services consistent with the appendix H. Following a request from the AER, the Qld DNSPs modelled each of their respective illustrative quoted service configurations in accordance with the material cost escalators set out in appendix H. These illustrative quoted service examples are set out in appendices N and O (confidential) of this draft decision.

18.6.2.3 Capital allowance

The Qld DNSPs proposed a capital allowance formula component to recover the return on and return of (depreciation) non–system assets used in the provision of individual quoted or fee based services.[1127] The AER notes that the Qld DNSPs proposed different methodologies to determine their respective capital allowances.

Energex

Energex stated that previously the QCA had calculated the amount of the capital allowance allocated to excluded distribution services. Further, Energex stated that based on its understanding of the QCA methodology it developed a general capital

[1126] Energex, response to information request AER.EGX.25.05, 9 October 2009, confidential; Ergon Energy, response to information request AER.ERG.24.06, 19 October 2009, confidential.

[1127] Energex, *Regulatory proposal*, July 2009, p. 324; and Ergon Energy, *Regulatory proposal*, July 2009, p. 490.

allowance expressed as a dollar per dollar of expenditure basis.[1128] It derived this allowance for each regulatory year as follows:[1129]

- determine the percentage allocation of the forecast total capex and opex on quoted and fee based services as a percentage of the forecast total spend
- multiply this percentage allocation by the proposed total revenue to be recovered from the use of all non–system assets. This represents the forecast return on and return of capital (in dollar terms) to be recovered from the provision of quoted and fee based services
- divide this amount by the forecast internal labour expenditure (in dollar terms) to be spent on the provision of quoted and fee based services which results in a capital allocation rate per dollar of internal labour expenditure.

The AER notes that Energex also proposed a separate capital allowance specific for large customer connections.[1130] However, it did not state how this allowance was determined. Energex's proposed capital allowances are set out in table 18.4.

Table 18.4: Energex's proposed nominal capital allowance for quoted and fee based services (dollar per dollar of internal labour expenditure) – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Capital allowance (general)					
Capital allowance (large customer connections)					

Source: Energex, response to information request AER.EGX.25.05, 9 October 2009, confidential; Energex, response to information request AER.EGX.05.10, 27 August 2009, confidential.

The AER notes that the information Energex used in these calculations was audited by an independent third party.[1131] The AER's review of Energex's illustrative quoted service examples and fee based services confirmed that it has correctly allocated the capital allowance to its internal labour (relative to the per dollar of internal labour expenditure). The AER considers the approach undertaken by Energex and the data used in these calculations is reasonable as it reflects the forecast non–system assets used in the provision of quoted and fee based services. However, the AER requires Energex to update its general capital allowance calculations to reflect the forecasts included in the AER's final distribution determination.

Energex did not justify how its capital allowance for large customer connections was determined. The AER has not been provided with sufficient information to substantiate Energex's proposed capital allowance for large customer connections and has therefore not been able to assess its efficiency. On that basis, the AER does not consider it appropriate to include Energex's proposed capital allowance for large customer connections in the derivation of prices for quoted and fees based services in

[1128] Energex, *Regulatory proposal*, July 2009, appendix 22.3, p. 3, confidential.
[1129] Energex, response to information request AER.EGX.05.10, 27 August 2009, confidential.
[1130] Energex, response to information request AER.EGX.25.05, 9 October 2009, confidential.
[1131] Energex, response to information request AER.EGX.25.03, 6 October 2009, confidential.

this draft decision. Accordingly in the absence of sufficient information, the AER has applied Energex's general capital allowance to all of its quoted and fee based services for the purposes of this draft decision. Table 18.5 sets out the AER's approved capital allowance for Energex.

Table 18.5: AER's nominal capital allowance for Energex's quoted and fee based services (dollar per dollar of internal labour expenditure) – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Capital allowance (general)					

Ergon Energy

Ergon Energy proposed a capital allowance for non–system assets to be applied throughout the next regulatory control period. In relation to vehicles it proposed a separate capital allowance expressed as a dollar per hour of use, which is to be escalated by standard control services' material cost escalator for vehicles.[1132]

The AER understands that the proposed change in the methodology for calculating the capital allowance is the primary driver of Ergon Energy's proposed price path for quoted and fee based services.[1133] Ergon Energy's proposed price path for each of its fee based services is set out in appendix P of this draft decision. The AER is concerned about the magnitude of the proposed increase in prices (ranging from 36 per cent to 98 per cent) for each individual fee based service in the first regulatory year of the next regulatory control period.

Capital allowance—non–system assets

Ergon Energy stated that its capital allowance equals the non–vehicle capital allowance (formula component CNS_i) for each excluded distribution service incurred in 2008–09 and 2009–10 divided by the direct costs (labour, materials and other costs) incurred in providing those services in 2008–09 and 2009–10.[1134]

The AER sought further information on the proposed capital allowance from Ergon Energy.[1135] Ergon Energy's response did not demonstrate how the proposed capital allowance was calculated. The AER has not been provided with sufficient information that substantiates Ergon Energy's proposed capital allowance and has therefore not been able to assess its efficiency. On that basis, the AER does not consider it appropriate to include Ergon Energy's proposed capital allowance in this draft decision. In the absence of sufficient information, the AER has not provided Ergon Energy a capital allowance for non–system assets in this draft decision.

The AER recognises that it is reasonable to include a capital allowance in the price cap formula to reflect the return on and return of non–system assets used in the provision of quoted and fee based services in the next regulatory control period. The AER will consider further information provided by Ergon Energy as part of its revised

[1132] Ergon Energy, *Regulatory proposal*, July 2009, AR443c_EE_Fixed Fee Services_Indicative Prices Calculation_2.xls, confidential.
[1133] Ergon Energy, response to information request AER.ERG.24.05, 16 October 2009, confidential.
[1134] Ergon Energy, response to information request AER.ERG.24.06, 19 October 2009, confidential.
[1135] AER, information request AER.ERG.24.06, 30 September 2009.

regulatory proposal and submissions in deciding on an appropriate capital allowance in the AER's final distribution determination. The illustrative quoted services examples and prices for fee based services set out in appendices N, O (confidential) and P respectively reflect this adjustment.

Capital allowance—vehicles

The AER considers Ergon Energy's standard and remaining asset lives in chapter 10 of this draft decision. The AER does not consider that it is appropriate for Ergon Energy to recover the standard asset life for its vehicles. To do so implies that either all Ergon Energy's vehicles used to provide quoted and fee based services are new at 1 July 2010 or that it has not recovered depreciation on its existing assets in the past. The AER is not aware that this is the case. Therefore, the AER will only permit Ergon Energy to recover depreciation consistent with the remaining asset life of its vehicles that is, 7.7 years as determined in chapter 10 of this draft decision.

Ergon Energy did not demonstrate how the proposed base depreciation rates were calculated. The AER has not been provided with sufficient information that substantiates Ergon Energy's proposed capital allowance for vehicles and has therefore not been able to assess its efficiency. On that basis, the AER does not consider it appropriate to include Ergon Energy's proposed capital allowance for vehicles in this draft decision. In the absence of sufficient information the AER has not provided Ergon Energy a capital allowance for vehicles in this draft decision.

The AER recognises that it is reasonable to include a capital allowance in the price cap formula to reflect the return on and return of vehicles used in the provision of quoted and fee based services in the next regulatory control period. The AER will consider further information provided by Ergon Energy as part of its revised regulatory proposal and submissions in deciding on an appropriate capital allowance in the AER's final distribution determination. The illustrative quoted services examples and prices for fee based services set out in appendices N, O (confidential) and P respectively reflect this adjustment.

18.6.2.4 On costs and overheads

Energex proposed to recover the following on costs:[1136]

- labour – labour related expenses that are not recovered in the base rate, including sick and bereavement leave, recreation leave and loading, long service leave, statutory and other holidays, workers compensation and payroll tax
- fleet – costs relevant to the operation and maintenance of vehicles
- materials – costs associated with warehousing and logistic functions.

Energex proposed to apply general overhead rates to all its direct costs (labour, contractor services and materials).[1137] Energex stated that its on costs and overheads are consistent with its approved CAM and will need to be updated annually according

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[1136] Energex, response to information request AER.EGX.25.03, 7 October 2009, confidential.
[1137] Energex, response to information request AER.EGX.05.10, 27 August 2009, confidential.

to the actual expenditure incurred.[1138] Table 18.6 sets out Energex's proposed on costs and overhead rates for the next regulatory control period.

Table 18.6: Energex's proposed nominal on cost and overhead rates (dollar per dollar of expenditure)[1139] – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Labour on costs					
Fleet on costs					
Materials on costs					
Overheads					

Source: Energex, *Regulatory proposal*, July 2009, appendix 22.3, confidential.

The AER notes that Energex's approved CAM recognises the allocation of on costs to recover expenditure items that do not meet the definition of a direct expense but arise as a consequence of incurring direct costs.[1140] Consistent with its approved CAM, Energex's fleet on costs have been added to the base labour rate (inclusive of the labour on costs). The labour and materials on costs have been applied to the base labour rates and materials costs.

The AER sought further information on the proposed labour on cost rates from the Qld DNSPs.[1141] Energex's response stated that its proposed on cost rate was based on a qualitative assessment of historical trends, seasonal factors and any known events that may impact in the future but it did not demonstrate how its proposed labour on cost rates were calculated.[1142] The AER has not been provided with sufficient information that substantiates Energex proposed labour on cost rates and has therefore not been able to assess its efficiency. Ergon Energy's response provided a disaggregated breakdown of its proposed labour on cost rate.[1143] The AER understands that Ergon Energy employed a bottom up methodology to determine it's proposed labour on cost rate.

In order to assess the reasonableness of the proposed labour on cost rates the AER has developed a benchmark labour on cost rate of 0.3124 (dollar per dollar of expenditure) for the Qld DNSPs. The benchmark labour on cost rate consists of two parts; time lost on costs (steps 1 to 3) and the other employment on costs (step 4). The AER developed its benchmark labour on cost rate on the following basis:

1138 Energex, response to information request AER.EGX.05.10, 27 August 2009, confidential.

1139 Energex applied labour on costs to the value of labour expenditure, fleet on costs were also applied to the value of labour expenditure, materials on costs were applied to the value of materials expenditure, and overheads were applied to the value of direct cost (labour, contractor services and materials) expenditure.

1140 Energex, *Cost Allocation Method*, 16 February 2009, p. 18.

1141 Energex, information request AER.EGX.25.03, 30 September 2009, confidential; Ergon Energy, information request AER.ERG.24.06, 30 September 2009.

1142 Energex, response to information request AER.EGX.25.03, 16 October 2009, confidential.

1143 Ergon Energy, response to information request AER.ERG.24.04, 16 October 2009, confidential.

1 there are 260 business days in a year[1144]

2 as an employee is not available to work every business day of the year the following number of business days on which an employee is paid but is unavailable for work are to be deducted:

- statutory holidays—10 days
- annual leave—20 days[1145]
- sick and personal leave—12 days[1146]
- carers and bereavement leave—two days
- parental leave—two days
- total of 46 days of time lost.

3 thus, an employee's salary can only be recovered from customers on 214 of the 260 business days per year. To recover the full dollar value of the employee's salary, the employee's base labour rate must be multiplied by the number of business days divided by the number of paid available days equating to a time lost on cost rate of 0.2150.

4 Other employment on costs for employees paid a base labour rate of *x* dollars per hour (*$x*):

- annual leave loading—*$x* multiplied by 0.175 multiplied by the amount (in weeks) of annual leave per year (4/52).[1147]
- long service leave provision—*$x* multiplied by 1.3 divided by the number of weeks in a year (1.3/52).[1148]
- workers compensation premium—*$x* multiplied by 0.0115[1149]
- cost of payroll tax—*$x* multiplied by 0.0475[1150]
- total other employment on costs—*$x* multiplied by ((0.175*4/52)+ +0.0115+0.0475) = 0.0840

5 The benchmark labour on cost rate of 0.3124 equals the sum of the time lost on cost rate (0.2150) and the other employment on cost rate (0.0840).[1151]

1144 The number of business days in a year (260) equals the number of weeks in a year (52) multiplied by five working days per week (five).

1145 Energex, *Union Collective Agreement 2008*, 13 October 2008, p. 40; Ergon Energy, *Regulatory proposal*, July 2009, AR094_Ergon Energy Union Collective Agreement, p. 35.

1146 The average number of days per employee for sick, personal, carers, bereavement and parental leave is an estimate.
Energex, *Union Collective Agreement 2008*, 13 October 2008 , p. 41; Ergon Energy, *Regulatory proposal*, July 2009, AR094_Ergon Energy Union Collective Agreement, p. 53.

1147 Energex, *Union Collective Agreement 2008*, 13 October 2008 , p. 41; Ergon Energy, *Regulatory proposal*, July 2009, AR094_Ergon Energy Union Collective Agreement, p. 78.

1148 Based on an annual leave entitlement of 13 weeks per ten years of employment

1149 The average rate in Queensland is 1.15 per cent.
http://www.deir.qld.gov.au/workerscompensation/advertising/index.htm,

1150 http://www.osr.qld.gov.au/payroll-tax/index.shtml

1151 Annual leave loading has not been included in the benchmark labour on cost rate, consistent with the Qld DNSPs' respective union collective agreements.

Based on this benchmark the AER does not accept that the Qld DNSPs proposed labour on cost rates are prudent and efficient and therefore will not apply the proposed rates in this draft decision. The AER will apply its benchmark labour on cost rate of 0.3124 (dollar per dollar of expenditure) to the Qld DNSPs in each regulatory year of the next regulatory control period.

The AER will not include Ergon Energy's proposed overtime labour on cost rate as the labour on costs rate should be applied to the employee classifications after hours base labour rate and therefore an appropriate on cost rate is provided.

The AER notes that a 9 per cent provision for superannuation has been added to the benchmark labour on cost rate for Ergon Energy since superannuation is not accounted for elsewhere.[1152] Energex stated that superannuation is included in its base labour rates.[1153] The AER will also apply an additional 9 per cent to Ergon Energy for superannuation. The AER's approved on cost rates for Energex and Ergon Energy are set out in table 18.7 and 18.8 respectively.

The AER notes that Energex's approved CAM states that indirect costs (overheads) are costs necessarily incurred in the provision of distribution services, but are not directly attributable to a specific activity or service. The overhead rate includes corporate support costs, staff training and travel, consultants' costs and occupancy costs.[1154] Consistent with the approved CAM overhead rates have been applied to direct costs (on costed labour and materials) used in the provision of quoted and fee based services.

The AER considers Energex's inclusion of on costs and overhead rates to its relevant formula components to be reasonable. Energex stated that the methodology for calculating on costs and overhead rates in its approved CAM requires these cost ratios to be updated on an annual basis. The AER notes that Energex's proposed on costs and overhead rates for each regulatory year of the next regulatory control period were based on its forecast direct expenditure (capex and opex) for all direct control services in that year. The AER considered these forecast were reasonable. Energex is required to update its on costs (except labour on costs) and overhead calculations as part of the AER's final distribution determination. The AER will fix Energex's on costs and overhead rates throughout the next regulatory control period as it provides both Energex and its customers certainty.

Ergon Energy has applied overhead rates determined for its customer service line of business consistent with its approved CAM. This overhead rate is applied to its direct costs (labour, materials and vehicles). The AER considers Ergon Energy's inclusion of overhead rate to its direct cost components to be reasonable. The AER's approved overhead rates for Energex and Ergon Energy are set out in tables 18.7 and 18.8 respectively.

[1152] Ergon Energy, *Regulatory proposal*, July 2009, AR094_Ergon Energy Union Collective Agreement, p. 35.
[1153] Energex, response to information request AER.EGX.25.03, 16 October 2009, confidential.
[1154] Energex, *Cost Allocation Method*, 16 February 2009, p. 20.

Table 18.7: AER nominal on cost and overhead rates for Energex (dollar per dollar of expenditure)[1155] – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Labour on costs					
Fleet on costs					
Materials on costs					
Overheads					

Table 18.8: AER nominal on cost and overhead rates for Ergon Energy (per cent)[1156] – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Labour on costs					
Overheads					

Notes: Ergon Energy's labour on cost rate includes a 9.00 per cent allowance for superannuation.

18.6.2.5 Profit margin

Energex

Energex proposed that a profit margin be applied to its direct costs (labour, contractor services and materials) to ensure competitive neutrality with other parties in the service market. Energex proposed that the profit margin would vary commensurate to the prevailing level of risk in the service market, however, it proposed to apply the lower bound of the range in order to facilitate the transition of quoted and fee based services to a competitive market.[1157]

The AER has allowed Energex to include a capital allowance formula component to recover the return on and return of non–system assets used in the provision of quoted and fee based services. The AER's consideration of Energex's proposed capital allowance is set out in section 18.6.2.3. Energex stated that a change in the methodology used to attribute the cost of non–system assets used in the provision of quoted and fee based services has increased the capital allowance from that charged in the current regulatory control period.[1158] The AER considers the approach undertaken

[1155] The AER requires Energex, consistent with its regulatory proposal, to apply labour on costs to the value of internal labour expenditure, fleet on costs are to be applied to the value of internal labour expenditure, materials on costs are to be applied to the value of materials expenditure, and overheads were applied to the value of direct cost (labour, contractor services and materials) expenditure incurred in the provision of an individual quoted or fee based service.

[1156] The AER requires Ergon Energy, consistent with its regulatory proposal, to apply labour on cost rates to the AER's approved employee classifications, and overheads are to be applied to the value of direct costs (labour, materials and vehicles) expenditure incurred in the provision of an individual quoted or fee based service.

[1157] Energex, *Regulatory proposal*, July 2009, appendix 22.3, p. 2, confidential.

[1158] Energex, *Regulatory proposal*, July 2009, appendix 22.3, p. 3, confidential.

by Energex and the data used in these calculations is reasonable as it reflects the forecast non–system assets used in the provision of quoted and fee based services.

The second step in Energex's capital allowance methodology involves the derivation of the proportion of total revenue to be recovered from the use of all non–system assets, which requires the use of the WACC. Energex's general capital allowance is derived using the WACC and therefore includes a profit margin for the investor. This provides assurance that Energex is able to recover an appropriate return on and return of capital (including a profit margin) for the use of non–system assets used in the provision of quoted and fee based services.

The AER recognises that firms operating in a competitive market necessarily include a profit margin as part of a quote for an individual job or project. However, these firms, unlike Energex, are not provided a rate of return (the WACC) for the use of their assets and therefore seek to add a profit margin to other cost components. The AER does not consider that Energex requires a further profit margin in addition to its capital allowance. The AER also notes that the QCA approved formula did not include a profit margin component.

The AER is not satisfied that the inclusion of the profit margin formula component reflects the recovery of efficient costs and therefore considers it appropriate to remove that component from Energex's formula for developing the prices of quoted and fee based services in the next regulatory control period.

18.6.2.6 Other costs

Ergon Energy

Ergon Energy's proposed formula included an 'other costs' component. It stated that total direct 'other costs' are calculated by summing the sponsor costs and the project risk held by asset manager contingency cost. This contingency cost is derived from an assessment of the monthly probability and frequency of project delays such as those due to rain.[1159]

The AER notes that the 'other costs' formula component is only applied for four of Ergon Energy's 37 illustrative quoted service worked examples and is not applied to any fee based services.[1160]

Contingency costs are a financial representation of the risk involved with the provision of certain quoted services. The inclusion of these contingency costs into the price cap formula passes these costs, and therefore the risk associated with the provision of a quoted service, to the customer. Planning for contingencies is not unreasonable, however, the AER considers that it is not appropriate for a DNSP to impose contingency costs on all customers as contingencies may not eventuate and individual customers have different attitudes towards the risk associated with contingency costs.

[1159] Ergon Energy, *Regulatory proposal*, July 2009, pp. 491–492.
[1160] Ergon Energy, *Regulatory proposal*, July 2009, attachments AR482c and AR443c.

The AER considers that contingency costs can be better managed as part of the commercial discussions between individual customers and a DNSP. This way, the parties can agree on who will accept the risk associated with contingencies occurring.

The AER also considers that the inclusion of allowances for contingency costs provides no incentive for a DNSP to seek productivity gains or to improve its internal processes and procedures. As such, the AER is not satisfied this component reflects the efficient cost of providing quoted services and therefore considers it is appropriate to remove the ‘other costs’ component from Ergon Energy’s formula used to derive prices for certain quoted services in the next regulatory control period.

18.6.2.7 Goods and services tax

The Qld DNSPs have included a goods and services tax (GST) component in their respective formulas. The AER accepts the inclusion of this component in the formula for developing the prices for quoted and fee based services in the next regulatory control period. However, consistent with its approach to standard control services, the AER has expressed all prices for quoted and fee based services exclusive of GST.

18.6.3 Price path

The AER’s price path for the Qld DNSPs’ individual labour and contractor services formula components used to derive the prices of quoted and fee based services is set out in table 18.2. A price path for the materials component is set out in appendix H of this draft decision. The AER’s approved capital allowance for Energex is set out in table 18.5.

A specific price path is not required for the Qld DNSPs on costs and overheads as these rates are not specific formula components. These rates in each regulatory year of the next regulatory control period are set out set out in tables 18.7 and 18.8.

The AER’s price path and prices for each of the Qld DNSPs’ individual fee based services is set out in tables P.5, P.6, P.7 and P.8 in appendix P of this draft decision.

18.6.4 Demonstration of compliance with the price cap

Quoted services

Energex stated that the prices for its quoted services will be calculated using its proposed formula to reflect the actual cost of service provision based on the specific requirements of the customer.[1161]

Ergon Energy did not specifically address how it would demonstrate compliance with the price cap control mechanism applicable to its quoted services.

Clause 6.12.1(13) of the NER requires a distribution determination to include a decision on how compliance with the control mechanism for quoted services is to be demonstrated.

[1161] Energex, *Regulatory proposal*, July 2009, p. 324

Under the price cap control mechanism, the price for each quoted service calculated in this draft decision is the maximum price that the Qld DNSPs can charge for that quoted service in a regulatory year. Compliance with the price cap control mechanism is to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the prices for each quoted service illustrative configurations in the relevant regulatory year of the next regulatory control period.

The proposed prices must be consistent with this draft decision for the relevant regulatory year. The pricing proposal should also include the volume of quoted services provided and the revenues recovered from the provision of quoted services in the preceding regulatory year.

Due to the variable nature of the inputs used to derive the prices of quoted services, the AER acknowledges that in some circumstances it may be difficult for customers to determine whether a quoted service provided by the Qld DNSPs is compliant with the price cap control mechanism. Under clause 6.22.1 of the NER, disputes arising over the terms and conditions of access to direct control services are considered an access dispute for the purposes of Part 10 of the NEL.

Fee based services

Energex stated that the 2010–11 proposed prices for its fee based services will be included in its initial pricing proposal and that the prices for each subsequent regulatory year of the regulatory control period would be based on the approved price path and would also be included in subsequent annual pricing proposals.[1162]

Ergon Energy did not specifically address how it would demonstrate compliance with the price cap control mechanism applicable to its fee based services.

Clause 6.12.1(13) of the NER requires that the AER’s distribution determination include a decision on how compliance with the control mechanism for fee based services is to be demonstrated.

Under the price cap control mechanism the price for each fee based service contained in this draft decision is the maximum price the Qld DNSPs can charge for that fee based service in a regulatory year. Compliance with the price cap control mechanism is to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the prices for each fee based service in the relevant regulatory year.

The proposed prices must be consistent with this draft decision for the relevant regulatory year. The pricing proposal should also include the volume of each fee based service provided and the revenues recovered from the provision of each service in the preceding regulatory year. As is the case for quoted services, disputes arising over the terms and conditions of access to direct control services are considered an access dispute for the purposes of Part 10 of the NEL.

[1162] Energex, *Regulatory proposal*, July 2009, p. 324.

18.7 AER conclusion

For Energex, the AER has approved in this draft decision the formula proposed by Energex to derive the prices for quoted and fee based services with the exception of the profit margin component. The formula to be used to derive the prices for quoted and fee based services for Energex is:

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Material} + \text{Capital Allowance} + \text{GST}$$

For Ergon Energy, the AER has approved in this draft decision the formula proposed by Ergon Energy to derive the prices (P_i) for quoted and fee based services with the exception of the ‘other costs’ component. The formula to be used to derive the prices for quoted and fee based services for Ergon Energy is:

$$P_i = L_i + M_i + CNS_i + CV_i + GST_i$$

The AER accepted Energex’s 2008–09 base labour rates and contractor rates and has escalated them to determine capped labour prices for the first regulatory year of the next regulatory control period. The AER did not accept Ergon Energy’s proposed 2008–09 base labour rates. The AER adopted the 2008–09 base labour rates accepted by the QCA and has escalated them to determine capped labour prices for the first regulatory year of the next regulatory control period. The labour cost escalators applied to standard control services apply as the price path to determine the Qld DNSPs’ base labour rates and contractor rates in the remaining years of the next regulatory control period.

The AER determined that the Qld DNSPs have frameworks in place which are likely to ensure that materials are sourced and managed efficiently. The material cost escalators applied to the Qld DNSPs’ standard control services, as set out in appendix H of this draft decision, is the price path for materials in the next regulatory control period.

The AER accepted Energex’s methodology for calculating a general capital allowance for non–system assets used in the provision of quoted and fee based services but requires it to update its calculations to reflect the forecasts included in the AER’s final distribution determination. The AER did not accept Energex’s proposed capital allowance for large customer connections. The AER was not satisfied that the development of the Ergon Energy’s capital allowances is efficient and has accordingly not provided it with a capital allowance in the next regulatory control period.

On costs and overheads will be applied to Energex’s direct costs (labour, materials and vehicles). These rates (except labour on costs) will be updated as part of the AER’s final distribution determination and will be fixed for the next regulatory control period. On costs will be applied to Ergon Energy’s base labour rates and overheads will be applied to its direct costs (labour, materials and vehicles).

The price path for each of the Qld DNSPs’ components to be used to derive the price for quoted services in the next regulatory control period are set out in tables 18.9 and 18.10.

Table 18.9: Price paths for Energex quoted services

Component	Conclusion
Labour	Table 18.2
Contractor services	Table 18.2
Materials	Table H.5
Capital allowance	Table 18.5
On cost and overhead rates	Table 18.7

Table 18.10: Price paths for Ergon Energy quoted services

Component	Conclusion
Labour	Table 18.2
Materials	Tables: H.11, H.13, H.15, H.20, H.24
On cost and overhead rates	Table 18.8

For quoted services, the AER has determined the capped price of providing the illustrative configuration of each individual quoted services in the first regulatory year of the next regulatory control period. The AER has also established a price path for each individual formula component. Compliance with the price cap control mechanism is to be demonstrated by each Qld DNSP providing, as part of their pricing proposals, the capped price and its calculation for each illustrative configuration of each individual quoted service in the relevant regulatory year. The AER's approved prices for each quoted service illustrative configuration is set out in appendix N and O (confidential) of this draft decision. The AER's approved prices do not represent a binding capped price for an individual quoted service due to variable nature of quoted services.

For fee based services, the AER has determined a capped price for individual service for the first regulatory year of the next regulatory control period and established a price path for each service. The price path for each fee based service is specified in appendix P.

Compliance with the price cap control mechanism is to be demonstrated by each Qld DNSP providing, as part of their pricing proposals, the capped price for each individual fee based service in the relevant regulatory year consistent with appendix P of this draft decision. The AER's approved price represents a binding capped price for each fee based service as the size, scale and scope of each service is known in advance of the service being undertaken.

18.8 AER draft decision

In accordance with clause 6.12.1(12) of the NER, the control mechanisms to apply to Energex's quoted services are:

- caps on the prices of indicative individual services in the first regulatory year of the next regulatory control period
- price paths, as set out in table 18.9, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(12) of the NER, the control mechanisms to apply to Energex's fee based services are:

- caps on the prices of individual services in the first regulatory year of the next regulatory control period
- price paths, as set out in appendix P of this draft decision for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Energex's compliance with the control mechanisms for quoted services and fee based services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 18.6.4 of this draft decision.

In accordance with clause 6.12.1(12) of the NER, the control mechanisms to apply to Ergon Energy's quoted services are:

- caps on the prices of indicative individual services in the first regulatory year of the next regulatory control period
- price paths, set out in table 18.10, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(12) of the NER, the control mechanisms to apply to Ergon Energy's fee based services are:

- caps on the prices of individual services in the first regulatory year of the next regulatory control period
- price paths, set out in appendix P of this draft decision, for the remaining years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Ergon Energy's compliance with the control mechanism for quoted services and fee based services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 18.6.4 of this draft decision.

Glossary

AASB	Australian Accounting Standards Board
ABS	Australian Bureau of Statistics
ACG	Allen Consulting Group
AEM	Access Economics Macro model
AEP	asset equipment plan
AFMA	Australian Financial Markets Association
AGL	AGL Energy Limited
AH	after hours
AMI	advanced metering infrastructure
ANSIO	Australian national state and industry outlook
ANZSIC	Australian and New Zealand standard Industry Classification
AOFM	Australian Office of Financial Management
AR	allowed revenue
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
ASA	average speed of answer
ASX	Australian Securities Exchange
ATO	Australian Taxation Office
AUD	Australian dollar
BBI	Babcock and Brown Infrastructure
BH	business hours
BMS	business management system
bppa	basis points per annum
CAM	cost allocation method
CAPM	capital asset pricing model
CARE	cyclone area reliability enhancement
CBD	central business district
CBRM	condition based risk management
CEG	Competition Economists Group
CFC	Construction Forecasting Council
CGS	Commonwealth Government Securities
CIA	corporation initiated augmentation
CICW	customer initiated capital works
CMS	customer management system
CPRS	carbon pollution reduction scheme
CRA	Charles River Associates

CRU	Commodities Research Unit
DLC	direct load control
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DRP	debt risk premium
DSM	demand side management
DUET Group	Diversified Utility and Energy Trust
DUOS	distribution use of system
EBA	enterprise bargaining agreement
EBSS	efficiency benefit sharing scheme
ECC	emergency cyclic capacity
ECCSA	Energy Consumers Coalition of South Australia
EGW	electricity, gas and water
EIC	Electricity Industry Code
ENA	Energy Networks Association
ESCV	Essential Services Commission of Victoria
ESO	Electricity Safety Office
EUAA	Energy Users Association of Australia
FBG	Fosters Brewing Group
Finity	Finity Consulting Pty Ltd
FMG	Fortescue Metals Group
FRC	full retail contestability
FY	financial year
gamma	the assumed utilisation of imputation credits
GFC	global financial crisis
GOS	grade of service
GSL	guaranteed service levels
GSP	gross state product
GWh	gigawatt hour
HV	high voltage
IBNR	incurred but not yet reported
ICT	information, communications and telecommunications
IPART	Independent Pricing and Regulatory Tribunal
IPO	initial public offering
IRC	Investment Review Committee
IT	information technology
IVR	interactive voice response

KPMG	KPMG Australia
kV	kilovolt, (one thousand volts)
LGAQ	Local Government Association of Queensland
LME	London Metal Exchange
Local Buy	Local Buy Pty Ltd is a company that was established in 2001 to provide comprehensive, value adding procurement services to Queensland local government. The company is a commercial entity that is wholly owned by the Local Government Association of Queensland.
LPI	labour price index
LV	low voltage
MAIFI	momentary average interruption frequency index
MAMP	mains asset maintenance policy
MAR	maximum allowed revenue
Maunsell	Maunsell Australia Pty Ltd
MCE	Ministerial Council on Energy
MCE SCO	Ministerial Council on Energy Standing Committee of Officials
McGrathNicol	McGrathNicol Corporate Advisory
MED	major event day
MEPS	minimum energy performance standards
MRP	market risk premium
MSS	minimum service standards
MTN	medium term notes
MVA	mega volt ampere
MW	mega watt, (one thousand kilowatts)
MWh	mega watt hour
NAMP	network asset management program
NARMCOS	network asset replacement maintenance capital expenditure operating expenditure summary
NDSC	negotiated distribution service criteria
NECF	National electricity customer framework
NEO	national electricity objective
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industrial Research
NMI	national metering identifier
NMP	network management plan
NPV	net present value
NTER	national tax equivalence regime

NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Cooperation and Development
OESR	Queensland Office of Economic and Statistical Research
Officer and Bishop	Professor Robert Officer and Doctor Steven Bishop
OH&S	occupational health and safety
Origin	Origin Energy Retail Pty Ltd
pa	per annum
PoE	probability of exceedence
PTRM	post–tax revenue model
PwC	PricewaterhouseCoopers
QCOSS	Queensland Council of Social Service
QTC	Queensland Treasury Corporation
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RFM	roll forward model
RIN	regulatory information notice
RIO	regulatory information order
RMU	ring main unit
SAC	standard asset customer
SAHA	SAHA International Ltd
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAMP	substation asset maintenance policy
SCADA	supervisory control and data acquisition
SEF	sensitive earth fault
SEO	seasoned equity offering
SFG	Strategic Finance Group Consulting
SKM	Sinclair Knight Merz Pty Ltd
SMA	simple moving average
SORI	AER, *Electricity transmission and distribution network service providers, Statement of revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009.
SPA	SPA Consulting Engineers Qld Pty Ltd
SPARQ	SPARQ Solutions
STPIS	service target performance incentive scheme
STS	structural time series
SWER	single wire earth return

Synergies	Synergies Economic Consulting
TFA	Toyota Finance Australia Ltd
the Officer framework	1994 Officer CAPM framework
the WACC review	AER, *Final decision, Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, 1 May 2009
theta	the utilisation rate of imputation credits
TNSP	transmission network service provider
TOU	time of use
TUOS	transmission use of system
TWI	trade weighted index
UbiNet	Ubiquitous Network
US	United States of America
USA	United States of America
USD	United States dollar
VCR	value of customer reliability
Victorian DNSPs	Victorian electricity DNSPs
WACC	weighted average cost of capital