Draft decision

South Australia

Draft distribution determination 2010–11 to 2014–15

25 November 2009

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AUSTRALIAN ENERGY REGULATOR

Request for Submissions

This document sets out the Australian Energy Regulator's (AER) draft distribution determination for ETSA Utilities for the period 1 July 2010 to 30 June 2015.

The AER will hold a pre–determination conference on its draft distribution determination on Wednesday 9 December 2009 in Adelaide for the purpose of explaining its draft determination 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 this draft distribution determination 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 determination, 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:

Chris Pattas
General Manager
Network Regulation South Branch
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

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 ETSA Utilities' regulatory proposal, proposed negotiating framework, consultancy reports and submissions from interested parties are available on the AER website.

Inquiries about the draft distribution determination or about lodging submissions should be directed to the Network Regulation South Branch on (03) 9290 1436 or alternatively by emailing QldSAdistribution@aer.gov.au.

Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
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
EMS	Energy and Management Services
ESCOSA	Essential Services Commission of South Australia
ESPIC	Electricity Supply Planning Industry Council
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

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 the South Australian electricity DNSP, ETSA Utilities, 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 South Australia that are set out in chapters 9 and 11 of the NER.

This is the first electricity distribution determination made by the AER on the price control regime to apply to ETSA Utilities. The previous determination that applied to ETSA Utilities for the period 2005–2010 was made by the Essential Services Commission of South Australia (ESCOSA).

Review process

The review process commenced with the publication of the AER's framework and approach decision in 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 service target performance incentive scheme and demand management incentive scheme.

Following the publication of its framework and approach, the AER liaised with ETSA Utilities to develop a Regulatory Information Notice (RIN). The purpose of the RIN was to obtain supporting information from ETSA Utilities to assist the AER in its assessment of the regulatory proposal against the requirements of the NER.

ETSA Utilities' regulatory proposal was published on the AER's website in July 2009 and submissions were sought from interested parties. The AER received 12 submissions which were considered as part of this draft decision.

The AER's detailed examination of ETSA Utilities' regulatory proposal 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 proposal and supporting data supplied by ETSA Utilities and provided advice to the AER on whether it considered the proposed expenditure was prudent and efficient.

In addition to PB, the AER also engaged Energy Management Services (EMS) to review the deliverability of ETSA Utilities' regulatory proposal and sought the assistance of the Electricity Supply Industry Planning Council (now the Australian Energy Market Operator (AEMO)) in reviewing ETSA Utilities' peak demand and energy sales forecasts.

In making its draft decision and draft distribution determination, the AER assessed ETSA Utilities' regulatory proposal to determine if it was in accordance with the requirements of the NER. Expert engineering consultants, as noted above, as well as financial and economic experts assisted the AER in its assessment of the proposal. The AER also considered the past performance of ETSA Utilities and the effectiveness of its policies and procedures, both in terms of past performance and in the development of its regulatory proposal.

Key expenditure drivers and considerations

ETSA Utilities' is expected to overspend its capital allowance and underspend the operating allowance established by the previous regulator, ESCOSA, for the five year period ending 30 June 2010. ETSA Utilities is expected to overspend its capital allowance by $185 million and underspend its operating allowance by $22 million. The AER reviewed the reasons for these over and underspends and considered that ETSA Utilities has appropriately taken these into account when developing its regulatory proposal. However, the AER notes that customer contributions are still problematic in determining appropriate forecasts for capital expenditure relating to network augmentation.

Capacity augmentation and customer related expenditure is a significant component and major driver of the capital works required over the next regulatory control period. South Australia is experiencing continuing growth in peak demand, with recent heatwaves resulting in network constraints that ETSA Utilities will need to address to maintain service standards. In addition, ETSA Utilities will be required to undertake a number of distribution projects to support mandated security of supply standards at the transmission level for the Adelaide central business district (CBD). This is a result of recent changes to the *Electricity Transmission Code*.

PB's assessment of ETSA Utilities' regulatory proposal confirmed the need for an increase in capital works expenditure in the next regulatory control period. ETSA Utilities forecast large increases in spending for capacity augmentation and the expected growth in customer numbers. Non–demand driven capital expenditure also incorporated large increases in areas such as asset replacement and safety expenditure.

After considering ETSA Utilities' regulatory proposal against the capital expenditure criteria in chapter 6 of the NER, the AER considers that ETSA Utilities' proposed capital expenditure is $638 million greater than an efficient level. The AER's draft determination results in a 28 per cent reduction in ETSA Utilities' proposed capital expenditure.

In particular, the AER considers that:

- the proposed demand driven capital expenditure for the low voltage network upgrade program and major customer connections program do not reflect efficient costs

- ETSA Utilities' proposed asset replacement capital expenditure does not reflect efficient costs

- the proposed security of supply capital expenditure relating to the Kangaroo Island network security project and elements of the network control project have not been demonstrated to be prudent and efficient

- ETSA Utilities' proposed safety related capital expenditure for the substation security fencing program and CBD aged asset replacement program do not reflect efficient costs.

The AER has therefore adjusted the proposed capital expenditure in the above areas.

The AER considers that ETSA Utilities' proposed expenditure required to support the Adelaide CBD distribution network is prudent and will provide customers with improved security of supply in and around the CBD.

PB assessed ETSA Utilities' operating expenditure proposal, and confirmed a need for higher operating expenditures in the next regulatory control period resulting from the increased size of the network, as well as workforce growth. A large part of ETSA Utilities' operating costs are allocated to network maintenance expenditure with increased asset inspections and higher emergency response expenditure forecast due to increasing asset age. A significant proportion of operating costs is also accounted for by ETSA Utilities' practice of expensing all overheads.

ETSA Utilities is proposing a significant change in its asset management strategy, towards a condition based approach which should provide longer term benefits of efficient asset replacement. Other notable changes include a new IT system to support the operations and workforce capabilities required to deliver the substantially larger capital expenditure program and a new regulatory requirement related to meter testing. Among other things, these have increased ETSA Utilities' operating expenditure requirements.

The AER has made reductions to ETSA Utilities' operating expenditure, across a number of expense items that are within the control of ETSA Utilities—for example, vegetation management and sponsorships, and non–controllable expense items including self insurance and debt raising costs.

The AER concludes that ETSA Utilities' proposed operating expenditure for the next regulatory control period is $131 million greater than an efficient amount. The AER's draft decision results in a reduction of 11 per cent on the total operating expenditure proposed.

The AER is also not satisfied that the materials and labour cost escalators used to forecast capital and operating expenditures reflect current and likely prospective economic conditions. The AER considers the escalators used by ETSA Utilities are likely to overstate future costs. The AER has revised the cost escalators and will update them to reflect economic conditions at the time of the final decision.

ETSA Utilities sought to depart from the AER's Statement of Regulatory Intent to calculate the weighted cost of capital (WACC) and proposed a market risk premium of 8 per cent instead of 6.5 percent. The AER has not accepted this proposal. For this draft decision the AER calculated an indicative nominal vanilla WACC of 10.02 per cent for ETSA Utilities. 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 ETSA Utilities based on the AER's approved capital and operating expenditure allowances. ETSA Utilities' total revenue for the 2010–15 regulatory control period is $3549 million (nominal).

In nominal terms, ETSA Utilities' network charges will increase by 14 per cent in 2010–11 compared to the preceding year. Network charges will increase by 6 per cent in subsequent years of the regulatory control period reflecting rising real input costs (both labour and materials), replacement of aging assets and continuing growth in peak demand. This is around 38 per cent less than the increases proposed by ETSA Utilities.

The average residential customer's annual electricity bill in 2010–11 is likely to increase by just over 5 per cent or around $77. Beyond 2010–11, further price rises for residential customers will be around 3 per cent or $40 each year.

This decision also implements three incentive schemes:

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

Arrangements for establishing metering charges are also provided for in the draft decision. This is a result of the AER's decision to separate a number of metering services from ETSA Utilities' standard distribution services to reduce the barriers to entry faced by alternative metering providers in the South Australian market.

Summary

Introduction

The Essential Services Commission of South Australia (ESCOSA) made the current regulatory determination for ETSA Utilities for a five–year period from 1 July 2005 to 30 June 2010 (the current regulatory control period). ETSA Utilities owns and operates the electricity distribution network in South Australia.

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

On 1 July 2009 ETSA Utilities submitted its regulatory proposal for the next regulatory control period to the AER. On 17 July 2009 the AER published the regulatory proposal and its proposed negotiated distribution service criteria (NDSC) for ETSA Utilities. Interested parties were invited to make submissions on the proposals and 12 submissions were received. ETSA Utilities presented its regulatory proposal at a public forum held in Adelaide on 6 August 2009.

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

- Parsons Brinckerhoff Strategic Consulting (PB)
- Australian Energy Market Operator (AEMO)
- 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 are:

- classification of services
- specification of the control mechanisms and methodologies for demonstrating compliance with the control mechanism
- the opening regulatory asset base (RAB) value
- 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 negotiation framework and NDSC that will apply to ETSA Utilities
- the schemes to provide incentives to ETSA Utilities 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 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 ETSA Utilities 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 to set the X factor for each year of the regulatory control period
- set out the form of control 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

ETSA Utilities regulatory proposal

ETSA Utilities proposed to vary the classification of services specified in the framework and approach by classifying alternative control metering services to standard control services. ETSA Utilities also proposed the AER's standard control metering service definition of standard small customer metering services should not specify the type 6 metering installation.

AER conclusion

The AER does not accept ETSA Utilities' proposal to reclassify the alternative control metering services as standard control services or its proposal to redefine standard control metering services without reference to type 6 metering installations. The AER has clarified the description of the fixed and variable standard small customer metering services and the non-standard small customer metering services. The AER has not amended the definitions of metering services to accommodate large customer non-type 1–4 metering services.

The AER's distribution service classifications are set out in appendix A of this draft decision. The procedures to be applied by ETSA Utilities for assigning customers to tariff classes or reassigning customers from one tariff class to another are specified in appendix B of this draft decision.

Arrangements for negotiation

ETSA Utilities regulatory proposal

ETSA Utilities submitted its proposed negotiating framework for the next regulatory control period. It categorised negotiated distribution services into two groups, structured the negotiating framework around these groups, and included provisions from current jurisdictional instruments.

AER conclusion

The NDSC applying to ETSA Utilities for the next regulatory control period is in appendix C of this draft decision.

The AER does not approve the negotiating framework as proposed by ETSA Utilities. The AER requires amendments to the negotiating framework as set out in appendix D of this draft decision.

Control mechanism for standard control services

ETSA Utilities regulatory proposal

ETSA Utilities proposed a weighted average price cap (WAPC) control mechanism for its standard control services. The WAPC formula proposed by ETSA Utilities was based on the framework and approach but had three modifications:

- the addition of a pass through term

- an amended X factor definition to allow for different X factors in each year of the next regulatory control period

- a revised definition of CPI.

ETSA Utilities also proposed that a forecast amount for transitional factors be included as a building block component in the determination of the X factor, rather than as a separate annual adjustment to the WAPC, as set out in the framework and approach.

ETSA Utilities proposed that transmission use of system (TUOS) costs be recovered using the approach applied to the NSW DNSPs, modified to account for a delay between when TUOS is paid and when it is recovered.

AER conclusion

The AER accepts ETSA Utilities' proposal that a WAPC be applied to its standard control services for the next regulatory control period.

The AER does not accept ETSA Utilities' proposal to forecast an amount for transitional factors as a building block component rather than an annual adjustment.

The WAPC formula to apply to ETSA Utilities for the next regulatory control period is:

$$(1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+U_t)\times(1+EDPD_t)\pm(passthrough_t)\geq\frac{\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}\times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}\times q_{t-2}^{ij}}$$

Where:

ETSA Utilities has 'n' distribution tariffs, which each have up to 'm' distribution tariff components, and where:

> regulatory year t is the regulatory year in respect of which the calculation is being made
>
> regulatory year $t-1$ is the regulatory year immediately preceding regulatory year t
>
> regulatory year $t-2$ is the regulatory year immediately preceding regulatory year $t-1$
>
> p_t^{ij} is the proposed distribution tariff for component j of distribution tariff i in regulatory year t
>
> p_{t-1}^{ij} is the distribution tariff being charged in regulatory year $t-1$ for component j of distribution tariff i

q_{t-2}^{ij} is the quantity of component j of distribution tariff i that was delivered in regulatory year $t - 2$

X_t is the allowed real change in average prices from year t – 1 to year t of the regulatory control period as determined by the AER

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

U_t is the undergrounding factor to be applied in regulatory year t

$EDPD_t$ is the EDPD transition factor for regulatory year t. It is a carryover of adjustments made in the ESCOSA 2005–2010 Electricity Distribution Price Determination (EDPD) comprising the previous K, Q, PU and SI factor adjustments and any adjustment for under/over recoveries of the demand management allowance set by ESCOSA for the current regulatory control period

$passthrough_t$ is the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year t as compared to regulatory year $t - 1$, as determined by the AER

CPI_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 $t - 1$.

The AER accepts ETSA Utilities' proposal to recover TUOS costs in a manner consistent with the approach used by the NSW DNSPs, without modification.

Opening regulatory asset base

ETSA Utilities regulatory proposal

ETSA Utilities proposed an opening RAB for the next regulatory control period of $3011 million as at 1 July 2010. The proposed opening RAB was derived by taking an opening RAB of $2634 million as at 1 July 2005 and rolling this value forward to 1 July 2010.

ETSA Utilities proposed an opening RAB as at 1 July 2005 that differed from the RAB contained in the NER due to the conversion of dollar values from a December 2004 to June 2005, an under spend of actual capex of $3.4 million in 2004–05, the inclusion of a revaluation of easements ($116 million), and a correction of a historical modelling error related to the ESCOSA's treatment of certain capital contributions ($16 million).

ETSA Utilities' roll forward modelling included metering assets associated with alternative control services.

AER conclusion

The AER does not approve the inclusion of ETSA Utilities' proposed easement revaluation and the reinstatement of capital contributions removed by ESCOSA in the roll forward of the opening RAB.

Metering assets associated with alternative control services have also been removed from ETSA Utilities' RAB for standard control services.

The RAB roll forward calculations for ETSA Utilities are set out in table 1 and provide for an opening RAB of $2768 million for standard control services for the next regulatory control period (as at 1 July 2010).

Table 1: AER conclusion on ETSA Utilities' opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB	2501.8	2590.2	2625.7	2698.2	2770.1
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	149.4	122.5	119.9	176.5	193.2
Straight-line depreciation (adjusted for actual CPI)	61.0	87.1	47.4	104.6	111.9
Closing RAB	2590.2	2625.7	2698.2	2770.1	2851.4
Difference between actual and forecast capex for 2004–05					–0.3
Return on difference					–0.2
Removal of metering assets					–82.6
Opening RAB at 1 July 2010					2768.4

(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.

Demand forecasts

ETSA Utilities regulatory proposal

ETSA Utilities based its growth related capex program on forecasts of peak demand. ETSA Utilities forecast peak demand on its network over the next regulatory control period using global (at network level, or top–down) and spatial (at zone substation level, or bottom–up) forecasts. It used the global peak demand forecasts to provide a consistency check against the spatial demand forecasts.

ETSA Utilities also used energy sales forecasts to convert building block revenues to network prices.

ETSA Utilities' forecasts of maximum demand, customer numbers and energy sales are provided in table 2.

Table 2: ETSA Utilities proposed maximum demand, customer numbers and energy sales

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15
Maximum demand 10% PoE (MW)	3129	3227	3358	3434	3522	3.0%
Customer numbers	828 162	838 160	846 778	854 779	863 230	1.1%
Energy sales (GWh)	10 977	10 989	10 900	10 687	10 596	–0.7%

AER conclusion

The AER accepts ETSA Utilities' proposed demand forecasts and customer number forecasts.

The AER considers that the energy sales forecasts proposed by ETSA Utilities do not provide a realistic expectation of the demand forecast. The AER considers that revising ETSA Utilities' forecast energy sales to the levels shown in table 3 provides a more realistic basis for determining the X factors under the weighted average price cap.

Table 3: AER conclusion on ETSA Utilities' maximum demand, customer number and energy sales forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand 10% PoE (MW)	3129	3227	3358	3434	3522
Customer numbers	828 162	838 160	846 778	854 779	863 230
Energy sales (GWh)	11 868	12 062	12 399	12 638	12 969

Forecast capital expenditure

ETSA Utilities regulatory proposal

ETSA Utilities forecast total capex of $2315 million ($2009–10) for the next regulatory control period. Table 4 sets out ETSA Utilities' proposed capex.

Table 4: ETSA Utilities capex proposal by expenditure purpose ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Demand driven						
Capacity	146.6	194.4	147.6	144.6	142.6	775.8
Customer connection	130.6	139.1	127.6	141.0	143.0	681.3
Quality, reliability and security of supply						
Asset replacement	79.7	91.4	96.8	98.9	99.9	466.7
Security of supply	15.5	45.9	65.3	33.8	9.9	170.4
Reliability	4.9	5.0	5.0	5.1	5.2	25.2
Safety and environment	29.4	36.4	40.0	42.0	42.7	190.5
Non-network expenditure	67.8	59.0	70.3	78.0	88.7	363.8
Other-superannuation and equity raising costs	19.3	21.6	20.1	19.5	18.3	98.8
Total (including customer contributions)	493.8	592.8	572.7	562.9	550.3	2772.5
Customer contributions	–87.4	–93.8	–85.0	–95.0	–96.0	–457.2
Total (net of customer contributions)	406.4	499.0	487.7	467.9	454.3	2315.3

AER conclusion

In assessing ETSA Utilities' forecast capex the AER reviewed:

- its governance framework, capex policies and procedures
- the methods and assumptions used to develop the capex proposal, including planning processes, demand forecasts and network planning criteria
- the need for the projects proposed in the regulatory proposal and whether the scope, timing and costs are efficient
- the cost estimation processes employed by ETSA Utilities
- the deliverability of the forecast capex program.

The AER considered ETSA Utilities' proposed capex allowance and is not satisfied that the proposed forecast capex allowance reasonably reflects the capex criteria of the NER. In particular, the AER considers that:

- the proposed demand driven capex for the low voltage network upgrade program and major customer connections program do not reflect efficient costs
- ETSA Utilities' proposed asset replacement capex does not reflect efficient costs

- the proposed security of supply capex relating to the Kangaroo Island network security project and elements of the network control project have not been demonstrated to be prudent and efficient

- ETSA Utilities' proposed safety related capex for the substation security fencing program and CBD aged asset replacement program do not reflect efficient costs

- the capex relating to superannuation and benchmark equity raising costs does not reflect efficient costs

- the expenditures associated with ETSA Utilities' application of cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.

Following the adjustments outlined above, and as detailed in table 5, the AER is satisfied an estimate of $1628 million for ETSA Utilities' forecast net capex reasonably reflects the capex criteria, taking into account the capex factors. The AER considers these adjustments are the minimum adjustment necessary to ensure ETSA Utilities' capex forecast meets the capex criteria.

Table 5: AER conclusion on ETSA Utilities' capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities proposed gross capex[a]	483.8	580.6	562.5	553.5	542.5	2722.9
Customer contributions	–87.4	–93.8	–85.0	–95.0	–96.0	–457.1
Adjustment to demand driven capex	–20.3	–21.0	–21.9	–23.1	–24.6	–110.9
Adjustment to asset replacement capex	–36.0	–44.4	–50.6	–48.3	–48.1	–227.3
Adjustment to security of supply capex	–5.1	–30.3	–48.7	–19.9	–1.4	–105.4
Adjustment to safety capex	–5.6	–3.4	–2.8	–3.6	–3.4	–18.8
Adjustment to other capex	–0.3	–0.3	–0.4	–0.4	–0.4	–1.8
Adjustment to cost escalators	–16.4	–17.2	–18.8	–24.5	–30.2	–107.1
Adjustment to remove alternative control metering costs[b]	–12.7	–13.5	–12.4	–13.7	–13.9	–66.3
AER net capex allowance	300.1	356.6	321.8	325.0	324.5	1628.2

Notes: Totals may not add due to rounding.
(a) Excludes proposed equity raising costs.
(b) Reflects the classification of metering services in chapter 2 of this draft decision.

The AER will allow ETSA Utilities to amortise a total amount of $9.2 million ($2009–10) in benchmark equity raising costs for the next regulatory control period.

Forecast operating expenditure

ETSA Utilities regulatory proposal

ETSA Utilities' total opex forecast for the next regulatory control period is $1176 million ($2009–10). Table 6 sets out ETSA Utilities' forecast opex for the next regulatory control period.

Table 6: ETSA Utilities forecast total opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Controllable opex						
Network operating costs	28.5	30.0	31.1	32.4	33.8	155.7
Network maintenance costs	83.5	87.7	93.0	99.0	103.9	467.1
Customer services	24.8	25.4	26.1	26.7	27.4	130.4
Allocated costs	49.9	54.3	57.5	62.2	63.9	287.8
Total controllable opex	186.7	197.4	207.7	220.3	229.0	1041.1
Uncontrollable opex						
Superannuation	10.1	10.5	10.8	11.2	11.6	54.2
Feed-in tariffs	5.7	6.9	7.8	8.7	9.7	38.8
Self insurance	3.4	3.6	3.7	3.9	4.0	18.6
Debt raising costs	4.1	4.3	4.5	4.7	4.9	22.5
Total uncontrollable opex	23.3	25.3	26.8	28.5	30.2	134.0
Proposed total opex	210.0	222.7	234.5	248.8	259.2	1175.0

AER conclusion

The AER considered ETSA Utilities' forecast opex and is not satisfied that the total opex forecast proposed by ETSA Utilities 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.

Based on its analysis of ETSA Utilities' regulatory proposal, the advice of PB and other information, the AER has applied a reduction of $131 million to ETSA Utilities' forecast opex. This represents a reduction of around 11 per cent and results in a revised opex allowance of $1044 million ($2009–10). The AER considers this reduction is the minimum adjustment necessary to ensure ETSA Utilities' opex forecast meets the opex criteria.

This revised opex forecast represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the opex objectives. The AER is satisfied that the revised total forecast opex of $1044 million over the next regulatory control period reasonably reflects the opex criteria, taking into account the opex factors. The AER's conclusion on ETSA Utilities' opex by category is in table 7.

Table 7: AER conclusion on ETSA Utilities' total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities' proposed forecast opex	210.0	222.7	234.5	248.8	259.2	1175.0
Adjustments to controllable opex	–4.3	–6.5	–8.6	–10.9	–13.5	–43.9
Adjustments to self insurance	–6.4	–6.5	–6.7	–6.8	–6.9	–33.2
Adjustment to debt raising costs	–2.7	–2.7	–2.8	–3.0	–3.1	–14.3
Adjustment to input cost escalators	–2.7	–5.5	–8.0	–9.9	–12.0	–38.0
Adjustment for workload escalator recalculated for adjusted capex and opex	–0.2	–0.3	–0.4	–0.3	–0.3	–1.6
Total AER approved opex allowance	193.7	201.2	208.0	217.9	223.4	1044.0

Estimated corporate income tax

ETSA Utilities regulatory proposal

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. ETSA Utilities proposed a gamma of 0.5, and stated it provided persuasive new evidence that the values attributed to gamma in the AER's statement of regulatory intent regarding WACC parameters (SORI) are neither robust nor safe.

ETSA Utilities proposed an allowance 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.

ETSA Utilities proposed a tax asset base of $1160 million as at 1 July 2010. This value included metering assets that the AER subsequently reclassified as alternative control services.

ETSA Utilities also notified the AER it omitted to include gifted assets (which are treated as income for tax purposes) in its calculation of the tax allowance.

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 ETSA Utilities' regulatory proposal and the supporting information provided do not constitute persuasive evidence for justifying 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 the underlying criteria.

The AER considers that ETSA Utilities' proposed tax remaining and tax standard asset lives are appropriate. The AER considers that ETSA Utilities' proposed opening tax asset base to be appropriate and reasonable, subject to the removal of metering assets used for alternative control services. The AER also accepted that gifted assets should be included in the tax calculation.

Using these inputs, the AER has used the PTRM to calculate the allowance for corporate income tax, as set out in table 8.

Table 8: AER conclusion on ETSA Utilities' corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	31.9	33.0	32.4	34.0	35.2	166.6

Depreciation

ETSA Utilities regulatory proposal

ETSA Utilities proposed a straight-line approach to calculating depreciation in the PTRM. Its proposed regulatory depreciation allowances are set out in table 9.

Table 9: ETSA Utilities proposed regulatory depreciation ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Regulatory depreciation	100.5	115.4	130.4	147.7	165.2	659.1

AER conclusions

The AER assessed the remaining asset lives and standard asset lives used by ETSA Utilities as inputs to its PTRM, and the resulting regulatory depreciation allowance. The AER accepts the remaining and standard asset lives as proposed by ETSA Utilities.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined ETSA Utilities regulatory depreciation allowances for the next regulatory control period, as set out in table 10. These figures also reflect the removal of metering assets used for alternative control services from the RAB for standard control services.

Table 10: AER conclusion on ETSA Utilities' regulatory depreciation ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Regulatory depreciation	100.3	113.1	126.6	142.4	157.9	640.4

Cost of capital

ETSA Utilities regulatory proposal

ETSA Utilities proposed a rate of return on capital of approximately 9.36 per cent.

The parameters proposed by ETSA Utilities are shown in table 11. The methods, values, parameters and credit rating proposed are consistent with the AER's statement of regulatory intent regarding WACC parameters (SORI), with the exception of the market risk premium (MRP).

ETSA Utilities considered that a MRP of 6.5 per cent, as determined in the SORI, is inappropriate and proposed a MRP of 8 per cent. It argued regulatory stability and certainty are desirable but are not an end in themselves, and what is primarily required is for the AER to have regard to the evidence presented.

ETSA Utilities proposed an indicative debt risk premium (DRP) of 4.57 per cent, noting that this figure will be updated for the final determination based on the agreed averaging period. ETSA Utilities 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.

Table 11: ETSA Utilities proposed WACC parameters

Parameter	ETSA	SORI
Gearing level (Debt/Equity)	0.60	0.60
Nominal risk free rate[a]	4.22%	4.22%
Market risk premium	8.00%	6.50%
Equity beta	0.80	0.80
Credit rating level	BBB+	BBB+
Debt risk premium[a]	4.57%	N/A
Expected inflation rate[a]	2.47%	N/A
Nominal vanilla WACC[a]	9.52%	N/A

(a) The numbers are indicative only.

AER conclusion

The SORI defines a number of the WACC parameter values to be adopted by ETSA Utilities 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 considers the information provided in support of the regulatory proposal does not constitute persuasive evidence for justifying a departure from a MRP of 6.5 per cent.

For this draft decision, the AER has determined a nominal vanilla WACC of 10.02 per cent for ETSA Utilities, which is slightly higher than that proposed by ETSA Utilities. This difference is due to an increase in the nominal risk-free rate since ETSA Utilities submitted its regulatory proposal. The impact of the increase in the nominal risk-free was partly offset by maintaining a MRP of 6.5 per cent.

Table 12 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 its final determination.

Table 12: AER conclusion on WACC parameters

Parameter	
Nominal risk–free rate	5.37%
Real risk–free rate	2.85%
Expected inflation rate	2.45%
Gearing level (Debt/Equity)	60:40
Market risk premium	6.5%
Equity beta	0.80
Debt risk premium	4.29%
Nominal pre-tax return on debt	9.66%
Nominal post–tax return on equity	10.57%
Nominal vanilla WACC	10.02%

Service target performance incentive scheme

ETSA Utilities regulatory proposal

ETSA Utitlities proposed that the AER apply the STPIS as set out in the AER's framework and approach subject to the variations set out below:

- total overall rewards or penalties for the STPIS be capped at ±5 per cent of revenue (±0.5 per cent for customer service)
- the Box–Cox transformation method be used for determining the major event day boundary under the STPIS
- a modified s–bank mechanism should apply
- performance targets should be based on four years of data.

AER conclusion

The AER approves the use of the Box–Cox transformation method by ETSA Utilities for the purpose of setting the MED boundary in the next regulatory control period. The AER rejects ETSA Utilities' proposal to apply a modified s–bank mechanism.

The AER has determined that the national distribution STPIS will apply to ETSA Utilities 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 and the telephone answering customer service parameter
- overall revenue at risk of ±3 per cent and ±0.3 per cent for the telephone answering parameter
- the incentive rates to apply to each applicable parameter are as set out in table 12.2 of this draft decision
- the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period as set out at table 12.4 of this draft decision
- the guaranteed service level (GSL) component will not apply while the ESCOSA's GSL scheme remains in place. In the event that the ESCOSA's GSL scheme is withdrawn the AER will implement such a scheme from the day the jurisdictional scheme is withdrawn.

Efficiency benefit sharing scheme

ETSA Utilities regulatory proposal

ETSA Utilities proposed the following costs be excluded from the EBSS:

- recognised pass through events
- non–network alternatives
- debt and equity raising costs
- self insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- expenditure that meets all the necessary requirements for an approved pass through event other than satisfying the materiality threshold.

AER conclusion

The AER will apply the EBSS in accordance with its final framework and approach for ETSA Utilities 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:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the DMIA
- other specific uncontrollable costs incurred and reported by ETSA Utilities during the next regulatory control period, which the AER considers should be excluded after assessment.

The AER reviewed the transitional arrangements in the NER which require it to observe the ESCOSA's Statement of Regulatory Intent in relation to the treatment of negative carryover amounts from ESCOSA's Efficiency Carryover Mechanism. The AER will allow negative opex carryover accrued in respect of the current regulatory control period Efficiency Carryover Mechanism to be deferred to offset any positive carryover accrued in the next regulatory control period, provided the negative carryover is accrued in an approved uncontrollable opex cost category under the EBSS.

Demand management incentive scheme

ETSA Utilities regulatory proposal

ETSA Utilities proposed applying a two part demand management incentive scheme (DMIS), as set out in the AER's framework and approach. It did not propose any alteration to the capped demand management innovation allowance (DMIA) of $3 million.

ETSA Utilities also supported the AER’s approach in applying Part B of the DMIS (forgone revenues) but stated that restricting recovery to projects approved under the DMIA alone was not appropriate.

AER conclusion

The AER will apply a two part DMIS to ETSA Utilities. The DMIS will comprise of a Part A (DMIA component) and a Part B (foregone revenue component). Part A is capped at $3 million in the next regulatory control period. The capped amount will be allocated to ETSA Utilities as an ex-ante allowance, in five equal annual instalments of $600 000. The ex-post review and operation of the DMIA will be as set out in the DMIS.

Part B is uncapped and will be applied as set out in the DMIS.

Pass through arrangements

ETSA Utilities regulatory proposal

ETSA Utilities proposed that the following seven events be included as nominated pass through events in the AER’s distribution determination:

- extraordinary event
- connection point event
- feed in tariff event
- industry standards change event
- retailer failure event
- native title event
- interim period event.

In addition, ETSA Utilities stated that the following events would constitute a ‘regulatory change event’ or ‘service standard event’ as defined in chapter 10 of the NER:

- the introduction of a requirement to roll out smart meters and/or peak demand management equipment
- the introduction of an emissions trading scheme
- the requirement to place 66kV powerlines underground.

ETSA Utilities proposed that the materiality threshold should be determined by subjective consideration of whether the occurrence of the event has a material, positive or negative, impact on the costs incurred by the DNSP.

AER conclusion

The AER accepts the following pass through events as nominated pass through events for ETSA Utilities:

- smart meter event
- carbon pollution reduction scheme event
- feed-in tariff event
- native title event
- a general nominated pass through event.

The AER does not consider that the other events proposed by ETSA Utilities meet the AER's assessment criteria and therefore those events are not accepted as nominated pass through events. The AER considers the proposed events either fall outside the scope of this decision 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

ETSA Utilities regulatory proposal

ETSA Utilities' calculation of annual revenue requirements and X factors are summarised in table 13.

Table 13: ETSA Utilities proposed annual revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation		100.5	115.4	130.4	147.7	165.2
Return on capital		272.3	301.9	340.3	377.1	411.7
Operating expenditure		208.3	225.4	242.9	263.5	280.7
Tax allowance		27.0	28.6	28.5	30.8	31.9
Transitional amounts		–16.5	1.7	3.4	2.0	0.0
Annual revenue requirements		591.6	673.0	745.4	821.1	889.4
Expected revenues	541.5	597.6	664.0	736.6	815.6	908.9
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–10.0	–10.0	–10.0	–10.0	–10.0

(a) Negative values for X indicate real price increases under the CPI–X formula.

AER conclusion

The AER calculates ETSA Utilities' revenue requirements and X factors based on its decisions regarding the building blocks.

The AER's draft decision results in a total revenue requirement for the next regulatory control period of $3549 million, compared to $3720 million proposed by ETSA Utilities. The main reasons for this difference reflect the net effect of:

- removal of the $243 million from ETSA Utilities' opening RAB
- removal of the $638 million from ETSA Utilities' forecast capex
- removal of the $131 million from ETSA Utilities' forecast opex
- a higher WACC than proposed by ETSA Utilities.

The size of the X factors were also significantly affected by the revised energy forecasts, which lowered the expected per unit price increases.

Table 14: AER conclusion on ETSA Utilities' annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	100.3	113.1	126.6	142.4	157.9
Return on capital	277.5	300.3	327.9	350.9	373.7
Operating expenditure	192.3	204.6	216.8	232.7	244.3
Tax allowance	31.9	33.0	32.4	34.0	35.2
Capex carryover	8.4	7.6	4.3	0.1	0.0
Annual revenue requirements	610.4	658.6	708.0	760.3	811.3
Expected revenues	616.4	653.2	703.9	756.8	818.4
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors (%)	–10.95	–3.90	–3.90	–3.90	–3.90

Alternative control services

ETSA Utilities regulatory proposal

ETSA Utilities proposed that the alternative control metering services be reclassified as standard control services and therefore, did not propose a separate control mechanism as required under the framework and approach. ETSA Utilities proposed to apply the same control mechanism as that applied to standard control services and stated that it had addressed the reasons for the separate alternative control classification via separate tariff components within the standard control WAPC.

AER conclusion

The AER does not accept ETSA Utilities alternative control services reclassification proposal. The AER will apply the WAPC control mechanism as set out in the framework and approach. ETSA Utilities is required to demonstrate compliance with the WAPC by providing, as part of its pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC formula approved by the AER.

1 Introduction

1.1 Background

Under the National Electricity Law (NEL) and the National Electricity Rules (NER),[1] 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 Essential Services Commission of South Australia (ESCOSA) made the current regulatory determination for ETSA Utilities 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. ETSA Utilities owns and operates the electricity distribution network in South Australia.

The AER has made this draft decision and draft distribution determination according to the relevant requirements of chapter 6 of the NER and the transitional requirements for South Australia contained in chapters 9 and 11 of the NER. The AER's principal task is to set the revenues that ETSA Utilities can recover or prices that ETSA Utilities can charge from the provision of direct control services in the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

On 1 July 2009 ETSA Utilities submitted its regulatory proposal and proposed negotiating framework 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 ETSA Utilities.

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, safety, 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 at the date the regulatory proposal is lodged. For the purposes of this draft decision and distribution determination for ETSA Utilities, the relevant version of the NER is version 30, which was in effect on 1 July 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 regulated DNSP to which the determination applies and any affected registered participant are, in accordance with the NER:[3]

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

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

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

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

(a) providing direct control network services; and

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

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

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

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

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

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

(a) in any previous–

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

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

(b) in the Rules.

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

[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 that the AER must apply in exercising its regulatory functions and powers for electricity distribution networks. In particular, the AER must make a distribution determination for ETSA Utilities 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(a) of the NER requires that a building block determination specify for a regulatory control period the following matters:

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

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

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

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

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

Determination in respect of alternative control services

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

Negotiating framework determination

Clause 6.7.3 of the NER requires that:

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

Clause 6.7.5(a) of the NER requires that:

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

Negotiated distribution service criteria

Clause 6.7.4 of chapter 6 of the NER requires that:

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

1.2 Transitional arrangements

Transitional arrangements have been included in the NER for the AER's first distribution determination for ETSA Utilities. The arrangements are contained in clause 11.26.2 of the NER and vary the time by which ETSA Utilities must submit its regulatory proposal. The determination will also be subject to the requirements of the South Australian distribution network pricing derogation in clause 9.29.5 of the NER.

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 ETSA Utilities' regulatory proposal and proposed negotiating framework 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 ETSA Utilities about the development of the regulatory information notice, pro forma templates and guidelines.

- Framework and approach—the AER consulted with ETSA Utilities and interested parties about the development of the framework and approach paper, with respect to the classification of services, control mechanism, and application of schemes. The framework and approach paper was published in November 2008, as required under clause 6.8.1 of the NER.

- Cost allocation method—in February 2009 the AER approved cost allocation methods of ETSA Utilities under clause 6.15.4 of the NER.

- Proposal—ETSA Utilities submitted its regulatory proposal and proposed negotiating framework to the AER on 1 July 2009. The AER assessed ETSA Utilities' proposal against chapter 6 of the NER and the AER's guidelines.

- Public consultation—the AER published ETSA Utilities' regulatory proposal and the AER's proposed NDSC on 17 July 2009 and called for submissions from interested parties. The AER held a public forum in Adelaide on ETSA Utilities' regulatory proposal on 6 August 2009, where ETSA Utilities and interested parties gave presentations.

- Submissions—the AER received 12 submissions on ETSA Utilities' regulatory proposal or the AER's proposed NDSC. The submissions are listed in appendix M.

- 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]

- PB has provided independent advice to the AER on these matters, based on its review. The AER has 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 forecasting experts—the AER engaged the Australian Energy Market Operator (AEMO) as a technical expert to advise in relation to demand forecasts.

[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.

- Additional technical advice—the AER engaged Energy and Management Services (EMS) to provide the AER with technical and engineering advice throughout the review process.[5] EMS assisted the AER in reviewing the technical aspects of material contained in ETSA Utilities' proposal, 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 (McGrathNicol) was engaged to review elements of the tax asset base for the post–tax revenue model.

- The AER's analysis and assessment of ETSA Utilities' regulatory proposal, submissions and consultants' advice is set out in this draft decision.

1.4 Structure of draft decision

The AER's consideration of ETSA Utilities' regulatory proposal and proposed negotiating framework and the negotiated distribution service criteria to apply are set out as follows:

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

- chapters 5 to 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

- chapter 17 sets out the control mechanism for alternative control services and the AER's review of alternative control services.

1.5 Overview of the SA electricity distribution network

ETSA Utilities' network covers 178 200 square kms, and serves around 803 000 customers. ETSA Utilities' network consists of over 723 000 poles and more than 85 000 km of line. Figure 1.1 is a map of the electricity network in South Australia, showing the area covered by ETSA Utilities' distribution network.[7]

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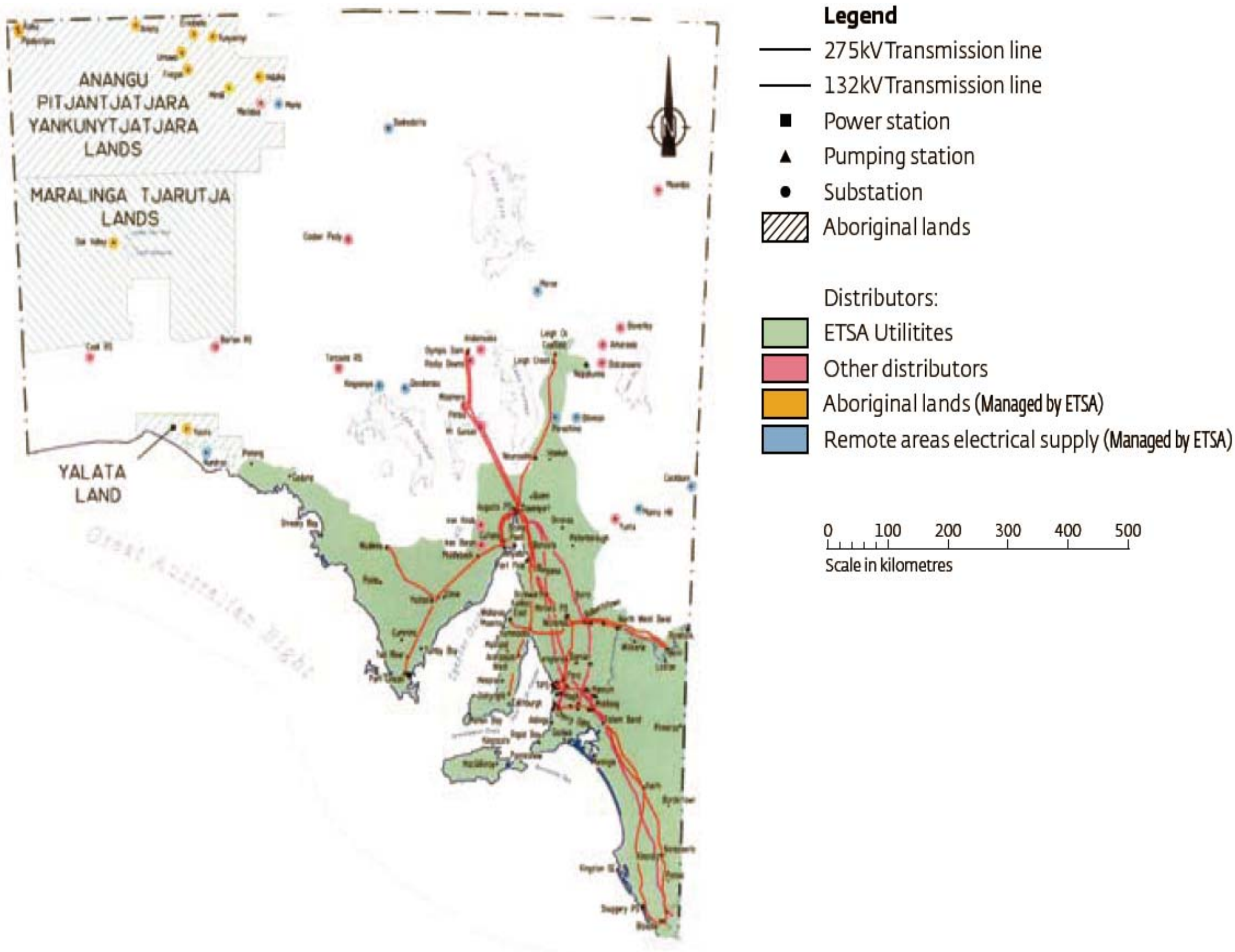
5 EMS is an engineering consulting firm.

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

7 ETSA Utilities, *ETSA Utilities Regulatory proposal 2010–2015*, 1 July 2009, p. 28.

Figure 1.1: ETSA Utilities distribution network



Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 29.

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 another transmission or distribution system.[8] Distribution services are classified as either direct control services, negotiated distribution services, or unregulated distribution services.[9]

This chapter sets out the AER's classification of ETSA Utilities' distribution services for the next regulatory control period. It draws on the AER's framework and approach for ETSA Utilities.[10] The chapter also sets out the AER's decision on the procedures for assigning and reassigning 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, the AER set out its likely approach to the classification of distribution services for ETSA Utilities, and its reasons for that approach.[11] Generally, the AER and ETSA Utilities are not bound by these classifications.[12] 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.[13] 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 reassigning customers to tariff classes for direct control services.

A DNSP is required to set out tariff classes as part of its pricing proposal that 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

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8 NER, chapter 10.
9 NER, clause 6.2.1(a).
10 AER, *Final Decision, Framework and approach paper: ETSA Utilities 2010–15,* November 2008.
11 The framework and approach paper must be prepared and published by the AER under clause 6.8.1 of the NER.
12 NER, clause 6.8.1(h).
13 NER, clause 6.12.3(b).

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 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 classified ETSA Utilities' distribution services into direct and negotiated distribution services as shown in table 2.1.

Table 2.1: ETSA Utilities direct control and negotiated distribution services

Service category	Direct control	Negotiated distribution
Network services	Network services at mandated standard	Network services at higher than mandated standard
Connection services	Connection services at mandated standard New or upgraded connection services (to the extent the user is not required to make a financial contribution under the *Electricity Distribution Code*)	Connection services at higher (or lower) than mandated standard New or upgraded connection services (to the extent that the user is required to make a financial contribution under the *Electricity Distribution Code*)
Metering services	Small customer standard meter provision and energy data services (type 6 metering installations) Unmetered metering services (type 7 metering installations) Two 'exceptional cases' of large customer metering services (type 1–4 meter provision services), being: customers consuming between 160 and 750 MWh per annum who have types 1–4 metering installations provided prior to 1 July 2000, and customers consuming more than 750 MWh per annum who have types 1–4 metering installations provided prior to 1 July 2005.	Small customer non-standard meter provision and energy data services (type 1–5 metering installations) Small customer special meter reads (including monthly reads) Large customer meter provision and energy data services (type 1–4 metering installations)
Public lighting services	Nil	Provision of assets, operation and maintenance Operation and maintenance 'Energy only' service
Other services	Nil	Remaining services, which include: Provision of stand-by or temporary supply Asset relocations Disconnections and reconnections Electricity Distribution and Electricity Metering Codes Embedded generation

Source: AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 36.

The AER further classified the direct control services into standard control and alternative control services as shown in table 2.2.

Table 2.2: ETSA Utilities' standard control and alternative control services

Service category	Standard control	Alternative control
Network services	All direct control network services	Nil
Connection services	All direct control connection services	Nil
Metering services	'Fixed' standard small customer metering services (type 6 metering installations) Unmetered metering services (type 7 metering installations)	'Variable' standard small customer metering services (type 6 metering installations) Two 'exceptional cases' of large customer metering services (type 1–4 meter provision services), being: • customers consuming between 160 and 750 MWh per annum who have type 1–4 metering installations provided prior to 1 July 2000 • customers consuming more than 750 MWh per annum who have type 1–4 metering installations provided prior to 1 July 2005.

Source: AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 37.

Although retailer of last resort (ROLR) services in SA are recognised as excluded distribution services in the current regulatory control period, the AER noted that these services do not fall within the definition of a distribution service in the NER.[14] The AER was therefore unable to classify these ROLR services for the purposes of the distribution determination.

2.4 ETSA Utilities regulatory proposal

2.4.1 Classification of services

ETSA Utilities submitted the following three changes to the framework and approach classification of services:[15]

- reclassification of the variable metering costs for small customers as a standard control service
- reclassification of the exceptional cases of legacy type 1–4 metering of large customer metering installations as a standard control service
- the AER's definition of the metering service that is classified as a standard control service should not specify a meter type.

14 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 34.
15 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 42–47.

2.4.2 Assigning customers to tariff classes

ETSA Utilities described its process for assignment and reassignment of customers to tariff classes and stated that it considered that its current approach aligns with the requirements of clause 6.18.4 of the NER. It acknowledged the obligation placed on the AER to consider the effectiveness of a DNSP's system of assessment and review under clause 6.18.4(a)(4). However, it stated that in the absence of an Ombudsman scheme equivalent to that in NSW, the AER should become the external body to review small customer objections to ETSA Utilities' assignment/reassignment decisions.[16]

2.5 Submissions

2.5.1 Classification of services

Origin Energy Retail Pty Ltd (Origin) submitted that the alternative control service classification for metering services consistent with the AER's final framework and approach is the most appropriate and effective method to address concerns relating to barriers to entry associated with the bundling of fixed and variable metering costs. It stated that the most appropriate classification does not turn on whether competition could be achieved through a standard control classification but was dependent on an assessment of the factors listed in clause 6.2.2 of the NER.[17]

The Trans Tasman Energy Group (TTEG) stated that it fully supported the determination of public lighting as a negotiated distribution service.[18]

2.5.2 Assigning customers to tariff classes

The South Australian Council of Social Service (SACOSS) noted the impact of residential customers on peak demand and stated that the current pricing mechanism relating to connection services is inadequate to ensure that correct pricing signals are provided to users of large ducted reverse cycle air conditioning. It submitted that an opportunity exists to introduce special cost recovery tariffs for the network capacity requirements resulting in greater equity and reduce cross subsidisation within residential network tariffs. It requested the AER acknowledge this as an important issue requiring further study.[19]

The Council of the Ageing (SA) Inc (COTA) stated that it supported the SACOSS submission. It noted that the AER should explore more equitable options to address costs associated with connections and potential cross subsidies between residential customers with large reverse cycle air conditioning systems and other residential users.[20]

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16 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 61–62.

17 Origin, *ETSA Utilities regulatory proposal 2010–11 to 2014–15*, 28 August 2009, pp. 1–4.

18 TTEG, *Submission to the AER in response to ETSA Utilities' regulatory proposal*, August 2009, p. 3. The TTEG represents the combined interests of the public lighting customers being the South Australian Department of Transport Energy and Infrastructure and the Local Government Association.

19 SACOSS, *Submission to the AER: ETSA Utilities 2010–15 distribution price review*, August 2009, pp. 6–7.

20 COTA, *ETSA distribution price review 2010–15*, 27 August 2009, appendix A, section 6.

2.6 Issues and AER considerations

2.6.1 Classification of services

Metering services

Alternative control metering services

ETSA Utilities addressed some of the factors listed in clause 6.2.2(c) of the NER to support its reclassification of the small customer metering services as standard control services. It considered that the AER had not given appropriate weighting to the factors under clause 6.2.2(c) and (d) of the NER. It submitted that the reasons provided for the reclassification of the small customer metering services also apply to its reclassification of the two ‘exceptional cases’ of type 1–4 meter provision services.

The primary reason for the AER’s classification in its framework and approach, of fixed and variable standard small customer metering (type 6 metering installation) separately as standard control and alternative control services respectively was to enable competition to develop.[21] Under the approach in the current regulatory control period, small customers opting for a type 4 metering service continue to pay for type 6 metering services because the metering charges are bundled with the distribution use of system (DUOS) charge.

Submissions received during the framework and approach process noted that this bundling approach was a barrier to entry faced by other metering providers wishing to enter the small customer market.[22] The AER assessed the argument in those submissions and having considered the matters listed in clause 6.2.2(c) of the NER, decided on its proposed classification for standard small customer metering services. The standard small customer metering services were classified in a manner that ensured unbundling of fixed and variable charges.[23]

In the current regulatory control period the two exceptional cases of type 1–4 meter provision services are classified as prescribed services. In its framework and approach the AER decided to classify these two exceptional cases of type 1–4 meter provision services as alternative control services. This classification attributed the costs of these services directly to the users of these services and ensured that small customers did not pay for these services. Further, given that large customer metering (type 1–4 meter installations) is competitive, unbundling the meter provision charge from the DUOS charge removed a barrier to entry faced by providers of large customer metering services.[24]

In its submission to the regulatory proposal, Origin submitted that there is strong potential for competition to develop for metering services in South Australia as the

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21 NER, clause 6.2.2(c)(1).

22 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 12.

23 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 31–32.

24 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 24 and 33.

cost of interval meters fall relative to the cost of accumulation meters. It also cited the example of the market for contestable metering in New Zealand.[25]

ETSA Utilities acknowledged that unbundling metering related charges for small customers could be beneficial. It also noted, in the context of the two exceptional type 1–4 large customer metering, that large customer metering is contestable and large customers or their retailers can and do choose alternative metering providers.[26]

The AER considers that the classification of fixed and variable standard small customer metering (type 6 metering installation) separately as standard control and alternative control services respectively is appropriate. The AER notes that both ETSA Utilities and other stakeholders recognise that such a classification will allow competition in the provision of metering services in South Australia.[27]

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 specifically addressed by ETSA Utilities in determining whether there is good reason to depart from the classification of services set out in its framework and approach. Below is the AER's consideration of the NER requirements specifically addressed by ETSA Utilities.

Effect on administration costs

ETSA Utilities' considered that its administrative costs and those of the AER would be increased under the approach proposed in the framework and approach. This includes the higher costs of establishing separate accounting procedures and maintaining separate accounts, ongoing regulatory reporting requirements and a requirement to develop a weighted average price cap specifically for alternative control services.[28] ETSA Utilities provided its estimates associated with these administrative costs (capital costs of about $0.25–$0.5 million and ongoing operational costs of about $0.1–$0.2 million per annum).[29]

The AER has considered the impact of its proposed classification of metering services on administrative costs. It stated that:[30]

> the potential increased administrative costs arising from classification in this manner are unlikely to outweigh the potential benefits from the more cost reflective pricing that will result from these classifications and the consequent unbundling of the 'variable' standard small customer metering charges from DUOS charges.

ETSA Utilities considered that the benefits of unbundling to reduce barriers to entry can be achieved using a simpler approach.[31] It proposed that the fixed and variable component be included in the standard control service classification (being subject to

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[25] Origin, *ETSA Utilities*, August 2009, p. 3.
[26] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 44–45.
[27] NER, clauses 6.2.2(c)(1) and (5).
[28] ETSA Utilities, *Regulatory proposal*, July 2009, p. 44.
[29] ETSA Utilities, email response, AER EU.14, 1 September 2009, response 1(e), confidential.
[30] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 32.
[31] ETSA Utilities, *Regulatory proposal*, July 2009, p. 45.

the one building block determination) and that it create a separate tariff component to recover the variable costs. ETSA Utilities stated that this pricing approach will not incur any material additional administrative costs. It further noted that although the proposed increase in administrative costs under the framework and approach classification is not large, it is not justified as there are no additional benefits to consumers from such a classification.[32]

Origin submitted that the pricing approach is unlikely to be as effective as the alternative control classification in terms of encouraging competition. Moreover, it noted that the most appropriate classification should be based on an assessment of all the factors listed in clause 6.2.2(c) of the NER.[33]

The AER understands ETSA Utilities' one-off administrative costs to be those associated with setting up internal systems to meet the requirement of the regulatory regime, including:

- removing the 'variable' metering assets from its regulatory asset base[34]
- allocating the cost associated with each category of distribution services in accordance with the AER approved cost allocation methodology[35]
- amending the applicable control mechanism to be consistent with the mechanism set out in the AER's framework and approach.[36]

ETSA Utilities acknowledged that the administrative cost is not large relative to its revenue. However, it does not consider that there are any additional benefits arising from the separate classification.[37] The AER considers that the potential for competition to develop represent a sufficient benefit to warrant one-off administrative costs.

ETSA Utilities informed the AER that as part of its pricing approach it has determined the metering services prices that reflect the fixed and variable costs of providing these services. It has also provided information setting out its methodology and notes that a similar methodology would be utilised in determining annual price adjustments.[38]

The AER notes that establishing this pricing approach would also incur some administrative costs and that it is not convinced that there is a significant difference between the administrative costs of the two approaches.

Desirability of consistency for similar services

ETSA Utilities stated that it will be the sole DNSP which has its metering services classified separately under fixed and variable costs. It also noted that in most

32 ETSA Utilities, email response, AER EU.14, 1 September 2009, response 1(e), confidential.
33 Origin, *ETSA Utilities*, August 2009, p. 2.
34 NER, clause S6.21(e)(7).
35 NER, clause 6.15.1.
36 NER, clause 6.12.3(c).
37 ETSA Utilities, email response, AER EU.14, 1 September 2009, response 1(e), confidential.
38 ETSA Utilities, email response, AER EU.14, 1 September 2009, response 3(e), confidential.

jurisdictions small customers metering services are standard control services and that in the NSW distribution determination the AER classified small customer metering services as a standard control service.[39]

Metering services have been classified in other jurisdictions as follows:

- The AER's NSW distribution determinations were made under the transitional chapter 6 rules of the NER. The 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 lack 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 at that time.[40]

- 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 is subject to the *Victorian Advanced Metering Infrastructure Order in Council*, 25 November 2008.[41] 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.[42]

- In the Queensland DNSPs draft decision the AER noted that given the maturity of the Queensland market it was not satisfied that there is sufficient potential for competition to develop in that market in the next regulatory control period. The AER did not reclassify the meter provision aspect of type 5–7 metering installations as an alternative control service.[43]

The AER recognises that although there is some inconsistency between jurisdictions these are the result of specific circumstances that preserved the presumption in favour of 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.[44]

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39 ETSA Utilities, *Regulatory proposal*, July 2009, p. 45.

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

41 AER, *Final Framework and approach paper for Victorian electricity distribution regulation, Citipower, Powercor, Jemena, SP Ausnet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, p. 3.

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

43 AER, *Draft decision, Queensland draft distribution determination 2010–11 to 2014–15*, November 2009, p. 16.

44 NER, clause 6.2.2(c)(4).

Presumption in favour of prior classification

The AER agrees with ETSA Utilities that there is a presumption under clause 6.2.2(d) of the NER that the AER's classification must be consistent with the current classification unless a different classification is clearly more appropriate.

The potential for competition to develop by unbundling metering charges from DUOS charges has been accepted by ETSA Utilities and stakeholders. As noted above, the AER is not convinced that the administrative costs due to its classification decision are significantly different to the costs already undertaken by ETSA Utilities in relation to its pricing solution. The differences between jurisdictions are due to specific transitional issues which preserved the presumption in favour of the prior classification and varying levels of market maturity.

Having considered the matters listed in clause 6.2.2(c) in its final framework and approach and in this draft decision, the AER considers that it has given due consideration and sufficient weight to all of the matters as required under the NER.

Conclusion

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 all of 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 services set out in its framework and approach.

Definition of standard small customer metering service

ETSA Utilities submitted that the AER should not refer only to type 6 metering installations in defining standard control metering services (see definition in table 2.2). It considers that such a definition restricts its ability to provide type 5 meters as a standard meter to small customers. It noted that any regulatory decision should not (inadvertently or otherwise) create a bias towards a particular technology or an artificial barrier to the adoption of new technology.[45]

Generally, the components of a metering installation include measurement transformers,[46] measurement devices[47] and data transport facilities.[48] The characteristics of different installations vary with the quantity of electricity flowing at the connection point. Based on the flow, metering installations have been separated into types.[49] Where the device is an interval meter and the data transport facility has a manual collection step then it is considered a type 5 meter. Where it is an accumulation meter and the data transport is either manual or electronic then it is considered a type 6 meter.[50] ESCOSA noted that the maximum value of the load flow

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45 ETSA Utilities, *Regulatory proposal*, July 2009, p. 46.

46 Current and voltage transformer.

47 Internal or external storage register for the measured data.

48 Manual or electronic.

49 AEMC, *Rule determination – National electricity amendment integration of NEM metrology requirements rule 2008*, 6 March 2008, p. 7.

50 AEMC, *Rule determination – National electricity amendment integration of NEM metrology requirements rule 2008*, 6 March 2008, p. 7.

for type 5 and 6 meters in South Australia is 160MWh as set out in its metrology procedure.[51]

In the current regulatory control period only type 6 meter installations for small customers (those using below 160 MWh of electricity per annum) are prescribed services and type 5 meter installations are negotiated distribution services.[52] In its framework and approach the AER noted that type 5 meters were of a non-standard nature and acknowledging the potential for these type 5 meters to compete with the contestable type 4 meters, it considered that a different classification was clearly not more appropriate. Therefore, consistent with the current regulatory control period classification the AER continued the classification of type 5 meter installations as a negotiated distribution service.[53]

In response to questions from the AER, ETSA Utilities confirmed that it was unlikely to deviate from providing type 6 meters as the standard small customer meter in the next regulatory control period. But it noted that under the AER's definition, should the costs and benefits of installing type 5 meters become economical it is precluded from doing so.[54]

The AER notes ETSA Utilities' response and considers that type 5 meters will continue to exhibit the non-standard characteristics noted in the framework and approach. It is also unclear when the cost and benefits of installing type 5 meters as the standard small customer meter will become economical. Therefore, the reasons why the AER did not depart from the current classification in making its framework and approach classification decision remain relevant. The AER therefore considers that it is reasonable to continue to classify the standard small customer metering service in a manner that restricts it only to type 6 meters consistent with the classification in the current regulatory control period. In conclusion, the AER considers that there is no good reason to depart from the classification of services set out in its framework and approach.[55]

Distinction between fixed and variable standard small customer metering service

In its framework and approach the AER classified:

- alternative control services ('variable' standard small customer metering services):
  - meter provision services in respect of meters meeting the requirements of a type 6 metering installation
  - energy data services associated with a type 6 metering installation to the extent that the costs are avoidable where ETSA Utilities ceases to provide the associated meter provision service.

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51 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A– Statement of reasons*, April 2005, p. 21, table 2.2.

52 Small customer is defined in section 4B of the *Electricity (General) Regulations 1997 (South Australia)* as a customer whose annual consumption level for a connection point is less than 160 MWh per annum.

53 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 24–25.

54 ETSA Utilities, email response, AER EU.14, 1 September 2009, response 3, confidential.

55 NER, clause 6.12.3(b).

- standard control services ('fixed' standard small customer metering services) – the energy data services associated with a type 6 metering installation to the extent that the costs are unavoidable where ETSA Utilities ceases to provide the associated meter provision service.

The AER's framework and approach recognised that at least the meter read component of energy data services would be avoided where the associated meter provision service was no longer provided by ETSA Utilities. However, it did not specifically identify this service (or any other) in that paper.

The AER considers it more appropriate to specify the metering service rather than distinguishing energy data services based on costs. The AER therefore has specified the quarterly meter read service as the service representing the avoidable cost component of the energy data service. The AER has amended its description of standard control and alternative control metering services and these changes are reflected in appendix A of this draft decision.

Non-standard small customer metering service

In its framework and approach the AER classified non-standard small customer metering services as a negotiated distribution service consistent with ESCOSA's classifications in the current regulatory control period. This negotiated distribution service was described in terms of incremental costs of providing non-standard meters to small customers.

ESCOSA's reason for describing the non-standard small customer metering excluded service in terms of incremental costs was that ETSA Utilities would continue to recover all costs associated with standard meters as part of DUOS charges from all small customers irrespective of whether the small customer opted for a non-standard meter.[56]

The AER has separated the quarterly meter read and meter provision charges of standard small customer metering services from the DUOS charge. These two services are alternative control services and are regulated under a weighted average price cap separate from the DUOS charge. Hence, in the next regulatory control period a small customer who opts for a non-standard meter will no longer continue to pay for its metering services via the DUOS charge. It will be subject to a separate metering charge and where it no longer receives a standard meter it will not pay for that service. The AER has therefore amended its description of non-standard small customer metering services and these services will no longer be distinguished in terms of incremental costs.[57] These amendments are reflected in appendix A of this draft decision.

Non type 1–4 large customer metering

ETSA Utilities informed the AER that since submitting its regulatory proposal it has become aware of another category of metering services that is, large customer non

56 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 19.

57 The AER notes that ETSA Utilities' appendix B2 defined these services without reference to costs although it did nor provide reasons for this change from the AER's framework and approach paper.

type 1–4 metering services (provided to large tier 1 customers).[58] It noted that several hundred customers fall into this category. ETSA Utilities stated this situation has arisen due to the classification of metering services on the basis of small and large customers and linking all large customers to type 1–4 meter installations.[59]

ETSA Utilities noted that its regulatory proposal was prepared on the assumption that non type 1–4 large customers metering would be charged on the basis of a standard metering service. It stated that it retains the view that its regulatory proposal approach is the appropriate treatment for these non type 1–4 large customer metering services. Therefore, it proposed that the AER amend the definition of metering services in the final framework and approach.[60]

The AER notes that ETSA Utilities' proposed amendments are designed to ensure that ETSA Utilities can continue to treat large customer non type 1–4 metering services as a standard control service. These amendments will change the definition of standard control, alternative control and negotiated distribution metering services and make them incompatible with the service classification in the current regulatory control period. The AER considers these amendments are in effect a reclassification of metering services.

ESCOSA's metering services arrangements for the current regulatory control period do not recognise any large customer non-type 1–4 meter installations. That is, all consumption thresholds above 160 MWh per annum at a connection point are serviced by a type 1–4 meter installation.[61] ETSA Utilities did not identify a large customer non-type 1–4 meter installation metering service during the framework and approach process.

The AER's framework and approach classification requires that the metering services to large customer non-type 1–4 meter installations be treated as a negotiated distribution service. The AER notes that this classification accords with clause 6.2.1(d) of the NER, which requires that the AER's classification be consistent with the current classification unless a different classification is clearly more appropriate.

ETSA Utilities has not addressed the matters listed in clause 6.2.1(c) of the NER demonstrating why service classifications that depart from the classification in the current regulatory control period are clearly more appropriate. In the absence of this information, the AER cannot assess the reasonableness of ETSA Utilities proposed reclassification of large customer non type 1–4 metering services.

Additional negotiated distribution services

ETSA Utilities did not propose to change service classifications other than the metering services discussed above. However, appendix B.2 of its regulatory proposal

58 Large customers (>160 MWh) that have remained with the incumbent retailer.

59 ETSA Utilities, email response, AER EU.14, 1 September 2009, response 3, confidential.

60 ETSA Utilities, email response, AER EU.14, 1 September 2009, response 3, and revised attachment B2, confidential.

61 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 21, table 2.2.

included a number of negotiated distribution services additional to that considered in the AER's framework and approach.

ETSA Utilities submitted that these additional services should be included in the final list of services to provide clarity to customers. It further stated that these services were not classified by ESCOSA but that the majority of them are specifically listed in its published price list which is annually reviewed by ESCOSA. ETSA Utilities noted that some services have been included to deter customers from misusing services or not fulfilling their obligations. These services and the reasons provided by ETSA Utilities for inclusion in the services list are:[62]

- New and upgraded connection point services: preliminary communications with a customer (ETSA Utilities appendix B2 section B.9.e.) — service is included in the current price list which was provided to ESCOSA before publishing.

- Asset relocation, temporary disconnection and temporary line insulation services: provision of network access management services to a network user or external party (ETSA Utilities appendix B2 section B.14.b.) — to clarify that the existing primary service is applicable irrespective of whether it is provided to a user or external party.

- Embedded generation services: services or costs associated with non-compliance of the embedded generator with the connection agreement (ETSA Utilities appendix B2 section B.15.b.) — to explicitly recognise this as a separate chargeable service.

- Other services: costs incurred as result of a customer not complying with ETSA Utilities standard connection agreement or other obligation (ETSA Utilities appendix B2 section B.16.k.) — it is reasonable to recover incurred costs.

- Other services: additional costs incurred where a service could not be completed by ETSA Utilities due to the customers fault (ETSA Utilities appendix B2 section B.16.l.) — service is included in the current price list which was provided to ESCOSA before publishing.

- Other services: provision of frequency interference investigation where the distribution system is not at fault (ETSA Utilities appendix B2 section B.16.m.) — reasonable to recover incurred costs.

- Other services: provision of supply interruption investigations where the distribution system is not at fault (ETSA Utilities appendix B2 section B.16.n.) — reasonable to recover incurred costs.

- Other services: provision of information to distribution network users or third parties not related to connection enquiries (ETSA Utilities appendix B2 section B.16.n.) — service is included in the current price list which was provided to ESCOSA before publishing.

62 ETSA Utilities, email response, AER EU.31, 29 September 2009, confidential.

The AER notes that the three services included in ETSA Utilities price list are currently being provided as negotiated distribution services. Although ESCOSA does not specifically approve these prices, ETSA Utilities confirm that ESCOSA is annually provided with a copy of the list of services prior to publication. The AER therefore considers that these three services have in effect been added to the negotiated distribution service list determined by ESCOSA for the current regulatory control period. [63] The AER will therefore continue the current classification for these services as it is not aware of any reason that justifies a departure.[64]

The AER considers it reasonable to include the two additional services relating to asset relocations and embedded generation as it is satisfied that the addition of these services enhances the clarity of two existing negotiated distribution services.

The three additional services that ETSA Utilities considers it reasonable to charge are activities that could be generally described as ‘fault response – not DNSP’s fault’. This is a standard activity for a DNSP and is generally charged a fixed fee. The AER therefore considers it reasonable to classify these additional services as negotiated distribution services in the next regulatory control period.

In the event that submissions on its draft decision provide new information the AER will reconsider the classification of these additional services.

Retailer of last resort

The AER understands that the South Australian government intends to provide a rule change proposal to the AEMC to enable ETSA Utilities to include ROLR services in the distribution determination applicable to it in the next regulatory control period. The AER will take into account the rule change process in making its final decision. The AER notes that in accordance with clause 6.10.2(c) any person can make a written submission on the draft distribution determination and this may extend to how relevant rule changes could apply to the final distribution determination.

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 ETSA Utilities 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.

ETSA Utilities provided its network tariff manual to demonstrate the internal system of assigning/reassigning customers to tariff classes.[65] The AER notes that this manual is an internal document, and that it does not set out a specific process by which an

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[63] ETSA Utilities, *Excluded services charges effective 1 January 2009*, Available at: <http://www.etsautilities.com.au/centric/news_information/electricity_information/excluded_service.jsp>.

[64] NER, clause 6.2.1(d).

[65] ETSA Utilities, email response, AER EU 19, 9 September 2009, confidential.

objection is escalated to an internal reviewer. The AER considers that an effective internal review system should clearly set out the process of escalation. This process should also be visible and transparent to users. A well documented transparent system is necessary for an effective system of review. ETSA Utilities does not appear to have such a system.

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 available form of external review for small retail customers.[66] ETSA Utilities has stated that an equivalent Ombudsman scheme that allows customers to refer tariff class assignment or reassignment disputes is currently unavailable in South Australia.

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.[67] The AER has included in its procedure for assigning customers to tariff classes that ETSA Utilities 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 is established to review such disputes the AER's procedure for assigning customers to tariff classes requires that ETSA Utilities notify customers of this review mechanism. In such circumstances customers may prefer to refer disputes to the jurisdictional Ombudsman rather than to the AER under Part 10 of the NEL.

The AER also notes SACOSS and COTA submitted that tariffs should be cost reflective and that the capacity requirements associated with reverse cycle air conditioning users should be equitably allocated to that class of customers. ETSA Utilities is required under clause 6.18.4(a)(1) of the NER and the AER's procedures for assigning customers to tariff classes to assign customers based on one or more of the matters listed in that clause including the nature and extent of customer's usage.

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

67 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 of 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 as to the term and conditions of access for a direct control service.

However the review of ETSA Utilities pricing proposal which sets out these matters is undertaken by the AER after the distribution determination.[68] Therefore, these issues will be considered when the AER reviews ETSA Utilities pricing proposal.

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

2.7 AER conclusion

2.7.1 Classification of services

The AER does not accept ETSA Utilities' proposal to reclassify the alternative control metering services as standard control services and its proposal to redefine standard small customer metering services without reference to type 6 metering installations. The AER also does not accept ETSA Utilities' proposal to amend the definitions of metering services classified as standard control, alternative control and negotiated distribution services to accommodate large customer non-type 1–4 metering services. The AER has clarified the description of the fixed and variable standard small customer metering service and the non-standard small customer metering services. The AER has accepted the additional negotiated distribution services submitted by ETSA Utilities.

In conclusion, except for the above mentioned changes, the AER does not consider that there is good reason to depart from the classification of services set out in its framework and approach.[69] The AER's distribution 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 ETSA Utilities, based on the principles in clause 6.18.4 of the NER, is set out in appendix B of this decision.

2.8 AER draft decision

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

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

[68] NER, clause 6.18.2(a).
[69] NER, clause 6.12.3(b).

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, as to the terms and conditions of access.

This chapter reviews issues raised in submissions and sets out the AER's considerations and conclusions on the NDSC and negotiating framework to apply to ETSA Utilities during the next regulatory control period.

3.2 Regulatory requirements

Negotiated distribution service criteria

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:[70]

> (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.

On 17 July 2009, the AER published its proposed NDSC to apply to ETSA Utilities.[71] As required under clause 6.7.4(b) of the NER, the AER's proposed NDSC gives effect

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

[71] AER, *Call for submissions, Proposed negotiated distribution service criteria for ETSA Utilities*, July 2009.

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 ETSA Utilities' negotiated distribution services is a constituent decision of the AER's distribution determination, under clause 6.12.1(16) of the NER.

Negotiating framework

Under clause 6.8.2(c)(5) of the NER, ETSA Utilities must submit a negotiating framework as part of its regulatory proposal for the next regulatory control period. A negotiating framework must set out the procedure that is to be followed during negotiations between a DNSP and any person wishing to receive a negotiated distribution service from the DNSP.[72]

A decision on the negotiating framework to apply to ETSA Utilities for the next regulatory control period is a constituent decision of the distribution determination, under clause 6.12.1(15) of the NER.

In reviewing the negotiating framework, the AER must ensure that it is satisfied that the negotiating framework adequately complies with the requirements of part D of chapter 6 of the NER. In particular, clause 6.7.5 of the NER provides that the negotiating framework must comply and be consistent with the applicable requirements of the relevant distribution determination, and the minimum requirements provided under clause 6.7.5(c), which are:

> (1) a requirement for the provider and a Service Applicant to negotiate in good faith the terms and conditions of access to a negotiated distribution service; and
>
> (2) a requirement for the provider to provide all such commercial information a Service Applicant may reasonably require to enable that applicant to engage in effective negotiation with the provider for the provision of the negotiated distribution service, including the cost information described in subparagraph (3); and
>
> (3) a requirement for the provider:
>
> (i) to identify and inform a Service Applicant of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiated distribution service; and
>
> (ii) to demonstrate to a Service Applicant that the charges for providing the negotiated distribution service reflect those costs and/or the cost increment or decrement (as appropriate); and
>
> (iii) to have appropriate arrangements for assessment and review of the charges and the basis on which they are made; and
>
> Note: If (for example) a charge, or an element of a charge, is based on a customer's actual or assumed maximum demand, the assessment and review arrangements should allow for a change to the basis of the charge so that it more closely reflects the

[72] NER, clause 6.7.5(a).

customer's load profile where a reduction or increase in maximum demand has been demonstrated.

(4) a requirement for a Service Applicant to provide all commercial information the provider may reasonably require to enable the provider to engage in effective negotiation with that applicant for the provision of the negotiated distribution service; and

(5) a requirement that negotiations with a Service Applicant for the provision of the negotiated distribution service be commenced and finalised within specified periods and a requirement that each party to the negotiations must make reasonable endeavours to adhere to the specified time limits; and

(6) a process for dispute resolution which provides that all disputes as to the terms and conditions of access for the provision of negotiated distribution services are to be dealt with in accordance with the relevant provisions of the Law and the Rules for dispute resolution; and

(7) the arrangements for payment by a Service Applicant of the provider's reasonable direct expenses incurred in processing the application to provide the negotiated distribution service; and

(8) a requirement that the Distribution Network Service Provider determine the potential impact on other Distribution Network Users of the provision of the negotiated distribution service; and

(9) a requirement that the Distribution Network Service Provider must notify and consult with any affected Distribution Network Users and ensure that the provision of negotiated distribution services does not result in non-compliance with obligations in relation to other Distribution Network Users under the Rules; and

(10) a requirement that the Distribution Network Service Provider publish the results of negotiations on its website.

Under clause 6.7.5(d) of the NER, the negotiating framework must not be inconsistent with any of the requirements of:

(1) rules 5.3 and 5.5 insofar as the negotiating framework applies to negotiated distribution services which would have been negotiated distribution services regardless of the operation of clause 6.24.2(c); and

(2) rules 5.3 and 5.4A insofar as the negotiating framework applies to negotiated distribution services which would have been treated as negotiated transmission services were it not for the operation of clause 6.24.2(c),

and any other relevant provision of this Chapter 6 and, in the event of any inconsistency, those requirements prevail.

A DNSP and a service applicant negotiating for the provision of a negotiated distribution service by the DNSP must comply with the requirements of the negotiating framework in accordance with its terms, as provided under clause 6.7.5(e) of the NER.

Under clause 6.12.3(h) of the NER, if the AER refuses to approve the proposed negotiating framework, the approved amended negotiating framework must be determined on the basis of the current proposed negotiating framework, and amended from that basis only to the extent necessary to enable it to be approved in accordance with the NER. As such, the AER's determination on a DNSP's negotiating framework must set out any requirements or amendments that are required in respect of the preparation, replacement, application or operation of the DNSP's negotiating framework.[73]

3.3 ETSA Utilities regulatory proposal

3.3.1 Negotiated distribution service criteria

ETSA Utilities has not proposed any amendments to the AER's proposed NDSC.

3.3.2 Negotiating framework

ETSA Utilities submitted its proposed negotiating framework for the next regulatory control period.[74] It categorised negotiated distribution services into two groups, structured the negotiating framework around these groups, and included provisions from current jurisdictional instruments.

Service grouping

ETSA Utilities noted that services classified by the AER as negotiated distribution services are defined as excluded services under the current regulatory regime, and jurisdictional arrangements have been developed and are currently in place for these services. In particular, ETSA Utilities stated:[75]

- ESCOSA's *Excluded services regulation (distribution) – Electricity industry Guideline No. 14* (Guideline 14) defines the scope and pricing principles for excluded services

- connection services are provided subject to the processes and timeframes set out in chapters 1 and 3 of the *Electricity Distribution Code of South Australia* (EDC)[76]

- many negotiated distribution services are high volume, repetitive and currently provided on a price list basis. ETSA Utilities issues the price list annually under Guideline 14.[77]

ETSA Utilities stated it interpreted clause 6.2.2 [clause 6.2.1] of the NER as meaning that the current arrangements concerning the classification of services should be retained unless an alternative classification is more appropriate.[78]

For these reasons, ETSA Utilities has grouped its negotiated services as follows:[79]

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73 NER, clause 6.7.3.

74 ETSA Utilities, *Regulatory proposal*, July 2009, attachment B.1, pp. 1–33.

75 ETSA Utilities, *Regulatory proposal*, July 2009, p. 49.

76 ESCOSA, *Electricity Distribution Code*, December 2005, chapter 3.

77 ESCOSA, *Excluded services regulation (distribution) – Electricity industry Guideline No. 14,* December 2005, p. 6.

78 ETSA Utilities, *Regulatory proposal*, July 2009, p. 49. The AER notes that the consideration outlined by ETSA Utilities is in fact provided under clause 6.2.1 rather than 6.2.2 of the NER.

- individually negotiated services—services requiring individual assessment and quotation due to likely cost variability. These are further divided into:
  - connection services—services associated with the formation of a new network connection or modification of an existing connection, including any associated extension or modification of the network
  - miscellaneous services—all other individually negotiated services
- price list services—a schedule of standard prices applying to high volume, repetitive and standardised services, reducing cost and administrative burden to ETSA Utilities and customers.

ETSA Utilities attempted to replicate the provisions of chapter 3 of the EDC, and the key requirements of Guideline 14 (including the establishment of pricing principles and annual publishing of prices) in its negotiating framework. It stated that these were included on its presumption that chapter 3 of the EDC and Guideline 14 will become redundant in the next regulatory control period.[80]

Structure of proposed negotiating framework

The ETSA Utilities proposed negotiating framework is structured as follows:[81]

- Part A – general provisions applicable to all negotiated distribution services
- Part B – provisions applicable to individually negotiated services
- Part C – provisions applicable to price list services
- Part D – administrative provisions applicable to all negotiated distribution services
- Schedule 1 – classification of negotiated distribution services into two groups
- Schedule 2 – pricing principles applicable to all negotiated distribution services
- Schedule 3 – information disclosure requirements for price list services
- Schedule 4 – provisions adapted from chapter 3 of the EDC, concerning connections requiring network extension and/or augmentation.

3.4 Submissions

The AER received three submissions, one from AGL Energy Limited (AGL) regarding the NDSC and submissions from the Trans Tasman Energy Group (TTEG) and the South Australian Minister for Energy on the negotiating framework.

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79 ETSA Utilities, *Regulatory proposal*, July 2009, p. 49.
80 ETSA Utilities, *Regulatory proposal*, July 2009, p. 50.
81 ETSA Utilities, *Regulatory proposal*, July 2009, p. 50.

AGL

AGL 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.[82]

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.[83]

AGL proposed the words "allocation of risk" be replaced with "equitable allocation of risk" or "reasonable allocation of risk". It 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.[84]

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.[85]

AGL proposed that prices be subject to market testing and benchmarking, providing a transparent approach to determining the efficiency of prices.[86]

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.[87]

AGL proposed that prices for negotiated distribution services be at least equal to the lower bound which equals the incremental costs of providing the services.[88]

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

82 AGL, *Proposed negotiated distribution service criteria for ETSA Utilities*, August 2009, pp. 1–4.
83 AER, *Proposed NDSC for ETSA Utilities*, July 2009, p. 1.
84 AGL, *NDSC for ETSA Utilities*, August 2009, p. 2.
85 AER, *Proposed NDSC for ETSA Utilities*, July 2009, p. 1.
86 AGL, *NDSC for ETSA Utilities*, August 2009, p. 3.
87 AER, *Proposed NDSC for ETSA Utilities*, July 2009, p. 1.
88 AGL, *NDSC for ETSA Utilities*, August 2009, p. 3.

> must reflect a DNSP's incremental cost of providing that service (as appropriate).[89]

AGL proposed that the word "difference" be replaced with "net difference", stating this would account for the potential benefit to the network performance that may derive from the additional services.[90]

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.[91]

AGL proposed that the words "efficient costs" be replaced with "incremental costs", stating this is a fairer approach to the criterion.[92]

TTEG

The TTEG's submission focussed on public lighting services.[93] While stating its full support for the AER's classification of public lighting in South Australia as negotiated distribution services, it proposed more prescriptive measures to regulating these services, similar to ESCOSA's approach to excluded services, in particular public lighting.

Public lighting pricing principles

The TTEG proposed that the pricing principles and specific regulatory requirements for public lighting from ESCOSA's current electricity distribution price determination and Guideline 14 be adopted, as ETSA Utilities' proposed pricing principles are unacceptable.[94] In particular, the TTEG submitted:[95]

- ETSA Utilities' pricing principles leave much of the price establishment process for it to consider, in contrast to the prescription of Guideline 14

- the consideration of market rates/benchmarks when establishing service prices was of concern as benchmarking is inexact, subjective and difficult given service variability.

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89 AER, *Proposed NDSC for ETSA Utilities*, July 2009, p. 1.
90 AGL, *NDSC for ETSA Utilities*, August 2009, p. 3.
91 AER, *Proposed NDSC for ETSA Utilities*, July 2009, p. 2.
92 AGL, *NDSC for ETSA Utilities*, August 2009, p. 4.
93 References made in the TTEG's submission to public lighting services relate particularly to those referred to in South Australia as street lighting use of system (SLUOS) services. Such services include the provision of public lighting assets, along with the operation and maintenance of those assets – ETSA Utilities retains ownership of those assets.
94 The AER notes that Section 2 of Guideline 14 provides pricing principles relevant to all excluded services, but also includes provisions specifically applicable to public lighting services.
95 TTEG, *Submission to the AER*, August 2009, pp. 1–7.

Public lighting price controls

The TTEG proposed additional prescription to the regulatory framework for public lighting services, including:[96]

- basing public lighting charges on a building block approach, incremented annually with an agreed formula based on the building blocks, including a regulatory asset base with weighted average cost of capital, depreciation and increasing opex by the CPI
- investigation of apparent anomalies in the application of overheads to public lighting charges and allocation of a fixed amount (negotiated) by ETSA Utilities[97]
- consideration of comparative favourability of public lighting loads on the network in establishing tariffs[98]
- the public lighting elevation charge be removed or set close to zero.[99]

Dispute resolution

The TTEG proposed that an independent body expedite the dispute resolution process as the current process is ineffective. Further, ETSA Utilities' dispute resolution process should be approved by the AER, consumer groups, or an independent body.[100]

Other concerns

The TTEG proposed that ETSA Utilities be required to undertake certain services, including public lighting services, that the AER identify these and that they be published by ETSA Utilities.[101]

Further, the TTEG stated prices for ETSA Utilities' price list services should be included in the distribution determination to facilitate price visibility.[102]

SA Energy Minister

The SA Minister for Energy, the Honourable Patrick Conlon MP (SA Energy Minister), noted that under the current South Australian regulatory regime, network users are able to have a disputed offer to connect assessed at no cost by ESCOSA, to determine if the offer is fair and reasonable. The SA Energy Minister proposed that this service continue to be available to customers at no cost and that the negotiating framework must not classify this form of dispute as an access dispute.[103]

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96 TTEG, *Submission to the AER*, August 2009, pp. 6–7.
97 TTEG, *Submission to the AER*, August 2009, p. 2.
98 TTEG, *Submission to the AER*, August 2009, p. 10.
99 TTEG, *Submission to the AER*, August 2009, p. 2.
100 TTEG, *Submission to the AER*, August 2009, p. 2.
101 TTEG, *Submission to the AER*, August 2009, p. 2.
102 TTEG, *Submission to the AER*, August 2009, p. 2.
103 SA Energy Minister, *Submission on ETSA Utilities' regulatory proposal*, 14 September 2009, p. 2.

3.5 Issues and AER considerations

3.5.1 Negotiated distribution service criteria

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

Criterion 3

The AER considers 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 what is an equitable, or reasonable, allocation of risk.

The AER considers that criterion 3 should not be amended.

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' to 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.

3.5.2 Negotiating framework

Pricing principles and connections regulations

In considering ETSA Utilities' proposed inclusion of pricing principles and connections arrangements arising from chapter 3 of the EDC, the AER has had regard to the overall purpose of the negotiating framework.[104] As set out in clause 6.7.5(a) of the NER, the purpose of the framework is to set out a procedure to be followed during

[104] ETSA Utilities, *Regulatory proposal*, July 2009, attachment B.1, Negotiating framework, Schedule 2 (pricing principles) and Schedule 4 (connections arrangements).

negotiations between a DNSP and a service applicant who wishes to receive a negotiated distribution service from the DNSP. While a negotiating framework is also assessed against the minimum requirements set out under clause 6.7.5(c), the AER considers that the NER does not imply that any matter can be included in a negotiating framework. The matter must be part of the procedure to be followed during the negotiations.

The AER considers that ETSA Utilities' proposed inclusions cannot be properly characterised as being part of the procedure to be followed during negotiations and hence does not consider these should form part of a negotiating framework. The AER considers that the proposed inclusions, particularly matters of pricing principles, fit more logically with the purpose of the NDSC. As set out in clause 6.7.4(a) of the NER, the NDSC sets out the terms and conditions of access to negotiated distribution services, including prices and access charges. Any proposal by a DNSP or interested parties to diverge from this set of criteria, such as via a proposed set of pricing principles, should be a proposal to vary the NDSC. ETSA Utilities may seek to propose its pricing principles for consideration in regard to the NDSC.

The AER notes the TTEG's concerns that ETSA Utilities' proposed pricing principles are insufficient, particularly for public lighting negotiated distribution services. The AER compared ETSA Utilities' pricing principles against the NDSC, which give effect to and are consistent with the negotiated distribution service principles set out in clause 6.7.1 of the NER. Although, ETSA Utilities has not proposed these pricing principles as amendments to the NDSC, the AER's review of attachment B.1 identified inconsistencies with the NDSC, including the following:

- the opening provision of the pricing principles, stating that ETSA Utilities will use 'reasonable endeavours' to comply with its pricing principles is inconsistent with the NER. Clause 6.7.4(a)(1) of the NER allows less discretion, requiring ETSA Utilities to apply the NDSC in negotiating prices and access charges.[105]

- principle (a) that prices are to 'signal' the economic costs of service provision is inconsistent with criterion 5 of the NDSC. Criterion 5 allows less discretion, providing that the price for a negotiated distribution service **must** reflect the costs that a DNSP has incurred or incurs in proving that service, and **must** be determined in accordance with the principles and policies set out in the DNSP's cost allocation method.

- principle (b) that prices will 'consider' prudent costs, a fair and reasonable profit margin, and 'have regard' to the particular market circumstances faced by ETSA Utilities is inconsistent with both criterion 5 and 2 of the NDSC. Both allow less discretion, with criterion 2 providing that the terms and conditions of access for a negotiated distribution service **must** be fair and reasonable. The AER has previously considered the word must in each criterion of the NDSC and maintains that it adequately reflects that the NDSC are enforceable principles, and avoids the

105 NER, clause 6.7.4(a)(1).

possibility of uncertainty with regard to the basis upon which DNSP's negotiate the terms and conditions of access to negotiated services.[106]

- principle (c) provides that consideration will be given to market rates and/or benchmarks when establishing prices for services where such market rates or benchmarks are reasonably available. The AER notes that the NDSC provides specific requirements on how prices should be determined, and that departing from these in order to consider benchmarks under certain circumstances that ETSA Utilities deems appropriate, is likely to add subjectivity and uncertainty to the process of negotiating.

Service grouping

In relation to the proposed grouping of negotiated distribution services into individually negotiated and price list services, the AER notes that ETSA Utilities is not precluded from distinguishing particular services within its negotiating framework. The AER notes the grouping of services does not impact the AER's decision to classify these services as negotiated distribution services. Consistent with this classification, they will all be subject to the arrangements for negotiation provided under the NER, as set out in section 3.2 of this draft decision. In particular, by definition they must be negotiated, their terms and conditions must be consistent with the NDSC, and the procedure for their negotiation must be as set out in the negotiating framework. As such, the AER considers that, regardless of how services are grouped in a negotiating framework, the provisions of a negotiating framework must meet the minimum requirements provided under clause 6.7.5(c) of the NER, for all negotiated distribution services.

The AER notes that ETSA Utilities' approach to its price list services involves the publication of a set list of prices for certain services. The publication of a list of indicative prices for negotiated distribution services can be beneficial to consumers from a price visibility perspective. However, the AER considers that the publication of a set price list is at odds with the notion that the terms and conditions (including price) are by definition negotiable. Further, the AER considers that any incorporation of prices or a price list into the negotiating framework does not fit with the purpose as set out in clause 6.7.5(a) of the NER, and as previously considered.

Should ETSA Utilities seek to publish an annual list of prices for its negotiated distribution services, such an approach would be beneficial but these prices must be indicative and thus subject to negotiation. The AER will not undertake any ex–ante assessment of a DNSP's negotiated distribution service prices as part of this determination. To the extent necessary the AER is only able to intervene ex–post under its dispute resolution responsibilities under Part 10 of the NEL.

NER minimum requirements

The AER has assessed the negotiating framework against the requirements of clause 6.7.5(c) of the NER, and identified required amendments before the AER can approve the negotiating framework as proposed by ETSA Utilities.[107]

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[106] AER, *Draft Decision, SP AusNet transmission determination 2008–09 to 2013–14,* 31 August 2007, p. 237.

Clause 6.7.5(c)(2) – commercial information provision

ETSA Utilities outlined in its *provisions applicable to all negotiated distribution services*, the commercial information it will provide if reasonably required by a service applicant.[108] To ensure consistency with clause 6.7.5(c)(2) of the NER, the AER considers that this provision be amended to acknowledge that the list of information types in no way restricts the type of information to be provided to a service applicant if that applicant reasonably requires it.

Further, this requirement is not met for price list services. ETSA Utilities proposed that for price list services, such information will be provided by virtue of the annual price list publication.[109] As discussed, a set price list is at odds with the notion that such services are negotiable. The AER considers that ETSA Utilities' negotiating framework must be amended, such that the requirement of clause 6.7.5(c)(2) of the NER regarding the reasonable provision of commercial information by ETSA Utilities, apply to all negotiated distribution services, including price list services.

Clause 6.7.5(c)(3) – cost determination and review

ETSA Utilities included a provision to the effect that in developing prices for negotiated distribution services, it will comply with the pricing principles in schedule 2 of its negotiating framework.[110] The AER considers this provision does not comply with clause 6.7.5(c)(3). Under this clause, ETSA Utilities must identify and inform service applicants of the reasonable costs and the increases or decreases in these costs of service provision, demonstrate that charges reflect these costs, and have appropriate arrangements for assessment and review of the charges and the basis upon which they are made.

The AER notes that for all negotiated distribution service charges, the basis referred to in the above clause, that is, the determination of all terms and conditions of access to negotiated distribution services, including price and access charges must be according to the provisions of the NDSC.

The AER considers an amendment is required to section 7 or elsewhere in the negotiating framework as appropriate, such that clause 6.7.5(c)(3) is addressed, and that any references to how costs and prices are determined, refer to the NDSC instead of ETSA Utilities' proposed pricing principles.

Clause 6.7.5(c)(5) – negotiation time limits

ETSA Utilities addressed this requirement in its *provisions applicable to individually negotiated services*,[111] but not Part C – *provisions applicable to price list services*. The AER acknowledges that should a list of indicative prices for negotiated distribution services be provided by ETSA Utilities, negotiations with a service applicant might require somewhat less time than for individually negotiated services.

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107 The minimum requirements of clause 6.7.5(c) are quoted in their entirety in section 3.2 of this draft decision.

108 ETSA Utilities, *Regulatory proposal*, July 2009, attachment B.1, section 6.

109 ETSA Utilities, *Regulatory proposal*, July 2009, attachment B.1, p. 5.

110 ETSA Utilities, *Regulatory proposal*, July 2009, attachment B.1, section 7.

111 ETSA Utilities, *Regulatory proposal*, July 2009, attachment B.1, sections 9 and 10.

However, as price list services must be negotiable, provisions must be included concerning timeframes for the negotiation and provision of these services. The AER considers that an amendment is required to Part C or elsewhere in the negotiating framework as appropriate, such that clause 6.7.5(c)(5) of the NER is addressed for all negotiated distribution services, including price list services.

Clause 6.7.5(c)(6) – dispute resolution

ETSA Utilities stated that all disputes will be dealt with by its internal dispute resolution process in the first instance, and should this fail, disputes will be dealt with by the AER in accordance with Part 10 of the NEL and Part L of the NER.[112]

The AER notes that this provision attempts to replicate the current dispute resolution process administered by ESCOSA for excluded services. Under that approach, ETSA Utilities submits its internal dispute resolution procedure for approval by ESCOSA as required under section 1.3.2 of the EDC.[113] Currently, disputes are dealt with via this procedure in the first instance, with ESCOSA only intervening should this process fail to resolve the dispute.[114]

However, the dispute resolution process that the AER will administer in the next regulatory control period differs to ESCOSA's. All disputes as to the terms and conditions of access to negotiated distribution services are to be administered by the AER in accordance with Part 10 of the NEL and Part L of the NER. As such, the AER considers amendments to sections 14 and 20 of the negotiating framework are required, to reflect this new arrangement, consistent with clause 6.7.5(c)(6) of the NER.

Clause 6.7.5(c)(7) – application processing expenses

ETSA Utilities addressed this requirement in its section 15 – *provisions applicable to individually negotiated services*, but not Part C – *provisions applicable to price list services*. ETSA Utilities' price list services must be negotiable. If ETSA Utilities requires payment relating to reasonable direct expenses in processing applications to provide these services, a provision must be included that provides for the arrangements for payment of these expenses. The AER considers an amendment is required to Part C or elsewhere in the negotiating framework as appropriate, addressing clause 6.7.5(c)(7) for all negotiated distribution services, including price list services.

Clause 6.7.5(c)(8) – impacts upon other network users

ETSA Utilities addressed this requirement in section 12 – *provisions applicable to individually negotiated services,* but not Part C – *provisions applicable to price list services*. The AER notes insufficient reason to preclude price list services from being subject to the requirement that DNSPs determine the potential impact on other distribution network users of the provision of negotiated distribution services. The

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[112] ETSA Utilities, *Regulatory proposal*, July 2009, attachment B.1, sections 14 and 20.

[113] ESCOSA, *Electricity Distribution Code*, December 2006, pp. 9–10. Accessible on <http://www.escosa.sa.gov.au/webdata/resources/files/061215-D-ElectricityDistributionCode.pdf>.

[114] ESCOSA, *Excluded electricity distribution services: a guide to dispute resolution*, December 2005, pp. 4–7. Accessible at <http://www.escosa.sa.gov.au/webdata/resources/files/051213-D-GuideDisputeResolution.pdf>.

AER considers an amendment is required to Part C or elsewhere in the negotiating framework as appropriate, addressing clause 6.7.5(c)(8) for all negotiated distribution services including price list services.

Termination of negotiations

ETSA Utilities included a provision in section 16.1 of its negotiating framework that should a service applicant terminate the negotiations for a negotiated distribution service, the applicant will still be liable for ETSA Utilities' incurred and/or committed costs in relation to the provision of that service.

The AER already noted that ETSA Utilities attempted to address clause 6.7.5(c)(7) in section 15.1 of its negotiating framework, by including a provision relating to reasonable direct expenses in processing service applications. As such, the AER considers that any additional costs outside of the reasonable direct expenses in processing service applications, should not be subject to a provision in the negotiating framework.

The AER considers that section 16.1 of the negotiating framework must be amended, removing references to incurred and/or committed costs in relation to the termination of negotiations, that are beyond those captured by clause 6.7.5(c)(7).

Other issues raised by the TTEG

The AER notes the TTEG proposed various prescriptive measures for regulating negotiated distribution (public lighting) services. The AER considers it reasonable to assess the TTEG's concerns with the proposed pricing principles, should ETSA Utilities decide to submit these for consideration under the NDSC. The setting of pricing principles, or criteria, is consistent with the relatively light–handed regulatory framework applying to negotiated distribution services.

However, arrangements requiring a more heavy–handed approach to price regulation, such as those proposed by the TTEG are at odds with the existing negotiated distribution service classification. The AER is not in a position to intervene ex–ante in the determination of prices, including via the following methods proposed by the TTEG:

- preparing a separate set of building blocks for negotiated distribution services
- incrementing prices via an agreed formula based on the building blocks
- applying a fixed and negotiated overhead component of public lighting charges
- any AER consideration of favourable treatment of network tariffs arising from public lighting loads.

The AER acknowledges the TTEG's desire to reduce the number of potential uncertainties surrounding public lighting services. However, the NDSC provides clear criteria upon which all negotiable prices are determined. To the extent that these prices increase or decrease over time, a DNSP's negotiating framework requires a DNSP to, for example, demonstrate how such costs and or increases/decreases in costs are determined and how the resulting costs are still consistent with the NDSC.

Consistent with the light–handed form of regulation applying to negotiated distribution services, the AER will only intervene should a dispute arise. On the matter of dispute resolution, the AER also notes the TTEG's concerns with the process being applied in the current regulatory control period, its proposal for an independent body to expedite the process and for ETSA Utilities' dispute resolution process to be reviewed and approved by the AER.

The AER notes that for the next regulatory control period, the dispute resolution process will not be that administered by ESCOSA, but the AER consistent with Part 10 of the NEL and Part L of the NER. Under this framework, the AER is not required to assess a DNSP's internal dispute resolution process, as all disputes should be brought to the attention of the AER when they arise. The AER has required an amendment to ETSA Utilities' negotiating framework to this effect.

Finally, the AER also notes the TTEG's proposal that ETSA Utilities be required to provide certain services, in particular, public lighting services, and that a provision to this effect be included in the negotiating framework. The AER considers that the negotiating framework sets out the procedure for negotiations and is not intended to be utilised to compel ETSA Utilities to provide particular services. The AER's service classification decision sets out the distribution services that have been classified and to the extent that terms and conditions of access to these services are the subject of a dispute then customers will have recourse to dispute resolution under Part L of the NER.

Issues raised by the SA Energy Minister

The AER notes that the SA Energy Minister proposed that customers requesting the AER to resolve a dispute regarding an offer to connect should not incur a cost, similar to the approach to this service administered by ESCOSA.

In the next regulatory control period, any disputes regarding the terms and conditions of any negotiated distribution service will be dealt with by the AER in accordance with Part 10 of the NEL and Part L of the NER. The AER has required a provision to this effect in ETSA Utilities' negotiating framework.

The AER notes under this framework, the notification of a dispute must be accompanied by the fee prescribed in the Regulations, as set out in Part 10, Division 2, section 125(2) of the NEL. Given this stipulation in the NEL, the AER considers that it cannot enforce the waiving of this fee, with regard to disputes concerning any negotiated distribution service including connections.

3.6 AER conclusion

Negotiated distribution service criteria

For the reasons set out in section 3.5.1 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 ETSA Utilities for the next regulatory control period are in appendix C of this draft decision.

Negotiating framework

Consistent with clause 6.12.3(g) of the NER, the AER does not approve the negotiating framework as proposed by ETSA Utilities, as it does not comply with the requirements of Part D of the NER. The AER's reasons for not approving are as set out in section 3.5.2 of this draft decision. As required under clause 6.12.3(h) of the NER, the AER requires amendments to the negotiating framework proposed by ETSA Utilities, for it to be approved in accordance with the NER. The required amendments are set out in appendix D of this draft decision.

Further, while not requiring specific amendment, the AER considers that price list services, and in particular any publication of a price list by ETSA Utilities is undertaken outside of the negotiating framework and should be expressed to be indicative only. A set list of prices is inconsistent with the notion that negotiated distribution services are by definition negotiable. Such prices will not be applied by the AER in the event of an access dispute.

3.7 AER draft decision

In accordance with clause 6.12.1(15) of the NER, the AER does not approve the negotiating framework proposed by ETSA Utilities for the next regulatory control period. In accordance with clause 6.12.3(g), the AER does not approve the negotiating framework on the basis that it does not adequately comply with the requirements of Part D of the NER.

In accordance with clause 6.12.3(h), the AER decides that ETSA Utilities' proposed negotiating framework needs to be amended as set out in appendix D of this draft decision.

In accordance with clause 6.12.1(16) of the NER, the NDSC to apply to ETSA Utilities for the next regulatory control period are set out 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 ETSA Utilities may recover from providing direct control services. Direct control services are categorised as either standard control services or alternative control services.[115] Classification of direct control services provided by ETSA Utilities is discussed in chapter 2 of this draft decision.

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

The control mechanism and assessment of ETSA Utilities' proposal regarding alternative control services is in chapter 17 of this draft decision.

4.2 Regulatory requirements

Clause 6.12.1 of the NER requires the AER to make the following constituent decisions 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 to pricing proposals in subsequent years to account for TUOS over or under recoveries (clause 6.12.1(19)).

4.2.1 Framework and approach

The AER published its framework and approach that sets out how a WAPC is to apply to ETSA Utilities' standard control services for the next regulatory control period.[116]

Clause 6.8.1, in conjunction with clause 6.12.3(c), of the NER does not allow the form of control mechanism that applies to ETSA Utilities to be varied from that specified in the framework and approach (that is a WAPC cannot be changed to a

[115] NER, clause 6.2.2.
[116] AER, *Final framework and approach paper, ETSA Utilities,* November 2008.

revenue cap).[117] However, the AER considers that the WAPC formula can be amended where this would reflect (or better reflect) the reasoning set out in the framework and approach.

The WAPC formula for ETSA Utilities as set out in the framework and approach was as follows:[118]

$$(1+CPI_t)\times(1-X)\times(1+S_t)\times(1+D_t)\times(1+U_t)\times(1+EDPD_t)\geq\frac{\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}\times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}\times q_{t-2}^{ij}}$$

Where:

ETSA Utilities has ‘n’ distribution tariffs, which each have up to ‘m’ distribution tariff components, and where:

regulatory year ‘t’ is the regulatory year in respect of which the calculation is being made

regulatory year ‘t–1’ is the regulatory year immediately preceding regulatory year t

regulatory year ‘t–2’ is the regulatory year immediately preceding regulatory year t–1

p_t^{ij} is the proposed distribution tariff for component j of distribution tariff i in regulatory year t

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year t–1 for component j of distribution tariff i

q_{t-2}^{ij} is the quantity of component j of distribution tariff i that was delivered in regulatory year t–2

CPI_t is calculated as follows:

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of regulatory year t

divided by

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of regulatory year t–1

117 See NER, clause 6.12.1(11).

118 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, appendix D.

X to be determined using the building block approach

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year t

D_t is the Demand Management Incentive Scheme factor to be applied in regulatory year t

U_t is the Undergrounding factor to be applied in regulatory year t, and

$EDPD_t$ is the electricity distribution price determination (EDPD) Transition Factor for regulatory year t. It is a carryover of adjustments made in the 2005–2010 EDPD comprising the previous K, Q, PU and SI factor adjustments.

4.2.2 Requirements specific to South Australia

Electricity Pricing Order

The *National Electricity (South Australia) Act 1996* contains a number of provisions governing the transfer of economic regulation of electricity distribution to the AER.[119] The AER must, according to this Act, give effect to the provisions of the Electricity Pricing Order (EPO) made by the South Australian Treasurer on 11 October 1999.[120] While most provisions relating to ETSA Utilities ceased on 30 June 2005 (at the end of ETSA Utilities' first regulatory control period), the EPO contains certain provisions that will continue to apply in the next regulatory control period. These provisions of the EPO will be taken to continue to apply as if the AER were the regulator under the EPO.[121]

Of relevance to the control mechanism, the EPO contains provisions regarding ETSA Utilities' recovery of costs relating to programs for the undergrounding of powerlines that are at the direction of the Minister. Clause 7.3(c) of the EPO states:

> If ETSA Utilities is required to undertake work in accordance with a program for the undergrounding of powerlines established by the Minister under the Electricity Act (SA) 1996, treat the costs of undergrounding as follows:
>
> …
>
> (ii) in respect of undergrounding that occurs during the regulatory period for which the price determination is being made:
>
> (A) In determining the aggregate revenue in each year after the year in which the undergrounding occurs, if any undergrounding is required in excess of that for which an allowance has already been made in making the price determination, an amount must be included to reflect a return on the new undergrounded assets and the recovery of their depreciation, based on a valuation of the assets at the efficient cost of undergrounding (and not at the cost of installing overhead lines) and the expected average life of the assets, and

119 *National Electricity (South Australia) Act 1996*, part 6 in particular.
120 *National Electricity (South Australia) Act 1996*, sections 18(4)(b) and 16(1).
121 *National Electricity (South Australia) Act 1996*, section 18(6)(a).

(B) In determining the aggregate revenue in the year after overhead poles and wires removed as a result of the undergrounding are removed from the asset register, an amount must be included to reflect the written down value of the overhead line and poles removed.

As noted above, the WAPC formula in the framework and approach included an undergrounding factor to take account of these specified costs.

Jurisdictional derogation for South Australia

Chapter 9 of the NER sets out derogations from the application of chapter 6 that are specific to the distribution determination for ETSA Utilities for the next regulatory control period. In particular:

- the distribution determination must allow ETSA Utilities to carry forward impacts associated with the calculation of maximum average distribution revenue under its 2005–10 price determination into the 2010–11 and 2011–12 regulatory years.[122]
- the following side constraint is to be applied to the tariffs for small customers for the next regulatory control period:[123]

  The fixed supply charge component of the tariff must not increase by more than $10 from one regulatory year to the next.

- any reduction in transmission network charges as a result of a regulatory reset (excluding reductions resulting from the distribution of settlements residue and settlement residue auction proceeds) must be paid to all customers.[124]

4.3 ETSA Utilities regulatory proposal

4.3.1 The form of control

ETSA Utilities proposed a WAPC for its standard control services.[125]

4.3.2 Scope of the WAPC

The WAPC applies only to standard control services. In the framework and approach, the AER indicated that certain metering services would be treated as alternative control services for the next regulatory control period.[126] ETSA Utilities has proposed those metering services be treated as standard control services for the next regulatory control period and the costs of these metering services be unbundled through the use of separate tariff components.[127]

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[122] NER, clause 9.29.5(b)(2).

[123] NER, clause 9.29.5(d). In preparing its distribution determination for the 2015–20 regulatory control period, the AER must consider whether this side constraint should continue with or without modification.

[124] NER, clause 9.29.5(f).

[125] ETSA Utilities, *Regulatory proposal*, July 2009, p. 54.

[126] AER, *Final framework and approach paper*, *ETSA Utilities*, November 2008, p. 33.

[127] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 55–56.

4.3.3 The WAPC formula

ETSA Utilities proposed three modifications to the WAPC formula contained in appendix 8 of the framework and approach:[128]

1. a pass through term ($passthrough_t$) be added to the left hand side of the WAPC formula, in percentage form, consistent with the approach used in the NSW final decision. ETSA Utilities proposed the $passthrough_t$ term be defined as:

   > $passthrough_t$ represents the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year 't' as compared to regulatory year 't–1', as determined by the AER.

2. the X factor be amended to reflect the possibility of different X factors in each year of the next regulatory control period. To this end, the X factor would be presented as 'X_t', rather than simply 'X' in the WAPC formula.
3. the definition of CPI be amended to correct for an error in the definition of CPI contained in the framework and approach. ETSA Utilities proposed that $1+CPI_t$ be defined as follows:

   > The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of regulatory year t;
   >
   > divided by
   >
   > The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of regulatory year t–1.

In addition, ETSA Utilities proposed that a forecast EDPD amount be included as a building block component in the determination of the X factor, rather than as a separate annual adjustment to the WAPC as set out in the framework and approach. To support this approach, ETSA Utilities noted:[129]

- If the carryover for the current regulatory control period were to be brought to account in the first year of the next regulatory control period, the $EDPD_t$ term could amount to a significant adjustment to revenue, forecast to be about $10 million for 2010–11. If such an amount were to be returned to customers in that single year, ETSA Utilities estimates distribution prices would fall in relative terms by about 2 per cent, followed by an equivalent increase in prices in the following year. ETSA Utilities stated that such instability in prices is undesirable.

- The AER accepted Country Energy's proposal to roll a significant accumulated TUOS over recovery into the building blocks cost build-up.

- Clause 6.4.3(a) of the NER provides for carryovers from the current regulatory control period to be incorporated into the building block, and clause 9.29.5 of the NER provides that the distribution determination by the AER for the next regulatory control period must:

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[128] ETSA Utilities, *Regulatory proposal*, July 2009, attachment C.1.
[129] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 56–57.

allow the SA distributor to carry forward impacts associated with the calculation of Maximum Average Distribution Revenue under the price determination into the 2010/11 and 2011/12 regulatory years.

If the forecast EDPD amount is included as a building block component, ETSA Utilities proposed that the $EDPD_t$ term in the WAPC formula still be retained. However, in this case ETSA Utilities proposed it be used as an annual unders/overs adjustment for any difference between the forecast EDPD amounts included in the building blocks and the subsequent actuals.[130]

4.3.4 Side constraints

ETSA Utilities proposed to apply side constraints to the following five customer classes:

1. major business
2. high voltage (HV) business
3. low voltage (LV) business (including unmetered supplies)
4. LV residential
5. metering data services and meter provision (excluding those metering services approved as negotiated services).

ETSA Utilities' proposal to unbundle metering services from other standard control services through the use of separate tariffs, means that each customer would face two tariffs, each with its own side constraint.[131]

The AER's framework and approach did not specify a formula for side constraints. ETSA Utilities proposed the following side constraints formula:[132]

$$(1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+D_t)\times(1+U_t)\times(1+EDPD_t)\times(1+2\%)\pm(passthrough_t)\geq\frac{\sum_{j=1}^{m}d_t^j\times q_{t-2}^j}{\sum_{j=1}^{m}d_{t-1}^j\times q_{t-2}^j}$$

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-2}^j is the audited quantity of component 'j' of the tariff class that was charged by the DNSP in year 't–2';

130 ETSA Utilities, *Regulatory proposal*, July 2009, p. 57.
131 ETSA Utilities, *Regulatory proposal*, July 2009, p. 60.
132 ETSA Utilities, *Regulatory proposal*, July 2009, attachment C.2.

X_t is the allowed real change in average prices from year t–1 to year t of the regulatory control period as determined by the AER. If X>0, then X will be set equal to zero for the purposes of the side constraint formula;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year t;

D_t is the demand management cost recovery factor for year t calculated to recover certain approved demand management implementation costs and foregone revenue incurred in year t–2;

U_t is the Undergrounding factor to be applied in regulatory year t; and

$EDPD_t$ is the EDPD Transition Factor for regulatory year t.

$passthrough_t$ represents the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year t as compared to regulatory year t–1, as determined by the AER; and

$1+CPI_t$ is calculated as follows:

> the Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of regulatory year t;
>
> divided by
>
> the Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of regulatory year t–1.

ETSA Utilities considered that the formulation above is mathematically equivalent to that approved by the AER for the NSW DNSPs, notwithstanding the addition of the S_t, $EDPD_t$ and U_t terms.[133] ETSA Utilities proposed the same revised definitions of the '$passthrough_t$' and '$1+CPI_t$' terms for the side constraints formula as it did for the WAPC formula.

As noted in section 4.2.2, the fixed supply charge for small customers cannot rise by more than $10 per annum under the transitional provisions for South Australia in the NER.[134] ETSA Utilities has undertaken to observe this requirement in its pricing proposal.[135]

4.3.5 Changes to tariff structures

ETSA Utilities has proposed the same approach to changes to tariff structures and reassignment of customers across tariffs as the reasonable estimates approach used for the NSW DNSPs. This approach would apply to changes to tariff structures for both the WAPC and side constraints formulas.

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133 ETSA Utilities, *Regulatory proposal*, July 2009, attachment C.2.
134 NER, clause 9.29.5(d).
135 ETSA Utilities, *Regulatory proposal*, July 2009, p. 60.

4.3.6 Recovery of transmission use of system costs

The TUOS costs that ETSA Utilities is seeking to be compensated for are:

- payments of TUOS to ElectraNet
- avoided TUOS payments to embedded generators.

ETSA Utilities proposed the same approach to the recovery of TUOS for the next regulatory control period as that applying to the NSW DNSPs. However, ETSA Utilities proposed a modification to the NSW TUOS settlements process to account for potential cash flow issues regarding the timing of TUOS payments and receipts. ETSA Utilities calculated that it faces on average a delay of approximately 45 days from when it pays TUOS to ElectraNet and subsequently recovers these amounts from customers.[136] To account for this delay, ETSA Utilities proposed a ‘within period interest charge’ be added to TUOS charges. The calculation of the interest charge is detailed in attachment C.6 to ETSA Utilities’ regulatory proposal. ETSA Utilities proposed this charge be applied to all forms of TUOS payments, including avoided TUOS payments to embedded generators and any payments for services provided by other DNSPs.

ETSA Utilities proposed that any under/over recoveries of TUOS from the current regulatory control period would be carried through to the next regulatory control period. However, in accordance with the current regulatory arrangements approved by ESCOSA, no interest would be applied to any under/over recoveries of TUOS occurring prior to 30 June 2010.

4.4 Submissions

Trans Tasman Energy Group (TTEG) proposed that the profit sharing factor (P factor) operated by ESCOSA during the current regulatory control period be retained for the next regulatory control period.[137]

4.5 Issues and AER considerations

4.5.1 The form of control

The AER accepts ETSA Utilities’ proposal that a WAPC be applied to its standard control services. This proposal is consistent with the AER’s framework and approach.

4.5.2 The scope of the WAPC

As discussed in chapter 2, the AER has further considered its position in the framework and approach regarding the classification of certain metering services. The AER has not accepted ETSA Utilities’ proposal that those metering services be treated as standard control services for the next regulatory control period. The AER has decided that these metering services will be treated as alternative control services and excluded from the WAPC for standard control services for the next regulatory control period.

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[136] ETSA Utilities, *Regulatory proposal*, July 2009, p. 63.
[137] TTEG, *Submission to the AER*, August 2009, p. 10.

4.5.3 The WAPC formula

4.5.3.1 ETSA Utilities proposed amendments

The AER accepts the addition of the $passthrough_t$ term to the WAPC formula as proposed by ETSA Utilities. The addition of this term clarifies how pass throughs will be treated under the WAPC and is consistent with the WAPC formula used for the NSW DNSPs. The AER also accepts the definition of $passthrough_t$ as proposed by ETSA Utilities. However, the AER notes that ETSA Utilities will be required to demonstrate in its pricing proposal that any increase/decrease in $passthrough_t$ has been included in the tariffs/tariff components of those tariff classes which gave rise to the expenses to be passed through.

The AER accepts the change to the X factor in the WAPC formula as proposed by ETSA Utilities. The omission of the subscript ‘t’ was an oversight in the framework and approach. The X factor will include the subscript ‘t’ to denote the regulatory year in question.

The AER agrees with ETSA Utilities that the CPI_t term in the WAPC formula in the framework and approach was incorrectly described. However, the AER disagrees with ETSA Utilities’ proposed approach of defining $1+CPI_t$ as a combined term. Mathematically, the AER considers that each term in the WAPC formula should be defined separately. The AER also considers that the CPI_t term can be defined more simply as follows:

> CPI_t is the annual percentage change in the Australian Bureau of Statistics (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.

The AER does not accept ETSA Utilities’ proposal to treat the transitional $EDPD_t$ factor as a building block component rather than an annual adjustment, as set out in the framework and approach.[138] The AER considers that:

- despite the expected negative effect on prices of the $EDPD_t$ term in year one of the next regulatory control period, ETSA Utilities’ customers will still experience real price increases overall in that year. The AER has come to this view even allowing for the effect of adding another adjustment to the $EDPD_t$ term for any underspend of ETSA Utilities’ demand management allowance during the current regulatory control period, discussed below.

- the AER’s decision to allow Country Energy to roll accumulated TUOS over recoveries into the building blocks is not comparable to the present circumstances, as the amounts were larger (about 5 per cent of the allowed revenues for 2009–10) in Country Energy’s case.

- while clause 9.29.5 of the NER does allow for carryover, this clause does not contain a requirement that carryovers be treated as a building block component rather than an annual adjustment. Clause 9.29.5 of the NER requires the AER to roll any carryover amounts ‘into the 2010–11 and 2011–12 regulatory years’.

[138] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 56.

Part A of the EDPD requires any difference between the demand management allowance ETSA Utilities was granted by ESCOSA for the current regulatory control period and subsequent actual expenditures be returned to customers or the DNSP.[139] How such an adjustment was to occur was not discussed in the framework and approach. The AER considers that had this matter been addressed at that time, it would have treated the issue in the same way as the other transitional issues.

Accordingly, the AER has decided to include an unders/overs adjustment related to the demand management allowance approved by ESCOSA as an additional component of the $EDPD_t$ term. The AER expects that an adjustment for this matter will be included in 2010–11 prices based on the difference between ETSA Utilities total expenditure in the current regulatory control period (including an estimate for the final few months of the current regulatory period). A further adjustment to 2011–12 prices will only be made regarding the estimated expenditure for the final few months of the current regulatory control period, and only if this estimate proves to be materially different from actual expenditures.

4.5.3.2 Retention of the profit sharing factor used by ESCOSA

As noted above, TTEG proposed that the P factor operated by ESCOSA during the current regulatory period be retained for the next regulatory control period.

The AER considered the retention of the P factor as part of its framework and approach.[140] The AER decided to retain the P factor on a transitional basis for the first two years of the next regulatory control period and with the P factor forming part of the $EDPD_t$ term in the WAPC formula. Otherwise, the AER decided that, under the NER, the P factor could not be retained for the next regulatory control period. TTEG's submission did not raise any new arguments to alter the AER's view on this matter.

4.5.3.3 Redundancy of the D factor

Since the publication of the framework and approach, the AER has determined that the $(1+D_t)$ term in the WAPC formula is not required for the next regulatory control period. In reaching this position, the AER observes that a demand management innovation allowance is already included as part of forecast opex, while the other components of the DMIS will only have effect in the second regulatory year of the 2015–20 regulatory control period (that is, when data becomes available for the final regulatory year of the next regulatory control period). Those other components are:

- any amount of allowance unspent or not approved over the next regulatory control period
- the time value of money accrued/lost as a result of the expenditure profile selected by the DNSP over the next regulatory control period
- any approved forgone revenue adjustment for the next regulatory control period.

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139 ESCOCA, letter to AER, 13 February 2009.

140 AER, *Final framework and approach paper, ETSA Utilities,* November 2008, p. 42; and AER, *Preliminary positions, Framework and approach paper: ETSA Utilities,* June 2008, p. 60.

Accordingly, the AER has removed the $(1+D_t)$ terms from the WAPC formula for the next regulatory control period. However, the term will be needed in the 2015–20 regulatory control period.

The revised WAPC formula is set out in full in the section 4.6.

4.5.4 Side constraints

The side constraints formula has a number of terms that are common to the WAPC formula. Given that these common terms refer to the same matters, they should be treated consistently across both formulas (the sole exception being the X_t term, which the NER prevents from being greater than zero in the side constraint formula).[141] Accordingly, the AER will require ETSA Utilities to change its proposed side constraint formula to include the revised definition of CPI_t term and to remove the redundant D_t term. Subject to those amendments being made to the side constraints formula, the AER accepts ETSA Utilities' proposed approach to side constraints as being consistent with clause 6.18.6(c) and clause 9.29.5(d) of the NER.

The side constraints formula is set out in section 4.6.2.

4.5.5 Changes to tariff structures

The AER accepts ETSA Utilities' proposal that changes to tariff structures and reassignment of customers across tariffs be subject to the same reasonable estimates approach as that used for the NSW DNSPs. This approach is set out in appendix E of this draft decision.

4.5.6 Recovery of transmission use of system costs

The AER accepts ETSA Utilities' proposed approach to the recovery of TUOS costs. An unders/overs account for TUOS, consistent with the approach used for the NSW DNSPs, will be adopted for ETSA Utilities. The AER considers this approach to be consistent with clause 6.18.7(b) of the NER.

The AER also agrees with ETSA Utilities that any under/over recoveries of TUOS from the current regulatory control period would be carried through to the next regulatory control period. However, in accordance with the current regulatory arrangements approved by ESCOSA, no interest would be applied to any under/over recoveries of TUOS for 2008–09 and 2009–10.

The AER does not accept ETSA Utilities' proposal to include an additional interest cost adjustment for a perceived delay between when TUOS is paid to ElectraNet and it is subsequently recovered from customers. The AER considers that the type of cash flow issue identified by ETSA Utilities is a one–off effect which would have occurred over the first 45 days of ETSA Utilities' operation in the NEM. ETSA Utilities operates on a continuous basis, and TUOS payments from customers can be used to offset TUOS payments to ElectraNet, even where the payments are not referencing the same period. The AER therefore does not accept the additional interest charge because this one–off effect has already occurred.

[141] NER, clause 6.18.6(c).

The operation of the TUOS overs and unders account (including transitional arrangements) is detailed in appendix F.

4.6 AER conclusion

As part of its pricing proposal, ETSA Utilities must submit to the AER proposed tariffs and charging parameters which correspond to the price terms contained in the WAPC and side constraint equations set out below. Each of the relevant percentage factors (for example, CPI_t) must be rounded to two decimal places before being applied in the WAPC and side constraints formulas.

4.6.1 Weighted average price cap

The WAPC formula to apply to ETSA Utilities for the next regulatory control period is:

$$(1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+U_t)\times(1+EDPD_t)\pm(passthrough_t)\geq\frac{\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}\times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}\times q_{t-2}^{ij}}$$

Where:

ETSA Utilities has ‘n’ distribution tariffs, which each have up to ‘m’ distribution tariff components, and where:

regulatory year *t* is the regulatory year in respect of which the calculation is being made

regulatory year *t*–1 is the regulatory year immediately preceding regulatory year t

regulatory year *t*–2 is the regulatory year immediately preceding regulatory year *t*–1

p_t^{ij} is the proposed distribution tariff for component *j* of distribution tariff *i* in regulatory year *t*

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year *t*–1 for component *j* of distribution tariff *i*

q_{t-2}^{ij} is the quantity of component *j* of distribution tariff *i* that was delivered in regulatory year *t*–2

X_t is the allowed real change in average prices from year *t* – 1 to year *t* of the regulatory control period as determined by the AER

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*

U_t is the undergrounding factor to be applied in regulatory year *t*

$EDPD_t$ is the EDPD transition factor for regulatory year *t*. It is a carryover of adjustments made in the 2005–2010 EDPD comprising the previous K, Q, PU and SI factor adjustments and any adjustment for under/over recoveries of the demand management allowance set by ESCOSA for the current regulatory control period

$passthrough_t$ is the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year *t* as compared to regulatory year *t*–1, as determined by the AER

CPI_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.

4.6.2 Side constraints

The side constraints formula to apply to ETSA Utilities for the next regulatory control period is:

$$(1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+U_t)\times(1+EDPD_t)\times(1+2\%)\pm(passthrough_t)\geq\frac{\sum_{j=1}^{m}d_t^j\times q_{t-2}^j}{\sum_{j=1}^{m}d_{t-1}^j\times q_{t-2}^j}$$

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-2}^j is the audited quantity of component *j* of the tariff class that was charged by the DNSP in year *t*–2

X_t is the allowed real change in average prices from year *t* – 1 to year *t* of the regulatory control period as determined by the AER. If X>0, then *X* will be set equal to zero for the purposes of the side constraint formula

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*

U_t is the undergrounding factor to be applied in regulatory year *t*

$EDPD_t$ is the EDPD transition factor for regulatory year t. It is a carryover of adjustments made in the 2005-2010 EDPD comprising the previous K, Q, PU and SI factor adjustments and any adjustment for under/over recoveries of the demand management allowance set by ESCOSA for the current regulatory control period

$passthrough_t$ is the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year *t* as compared to regulatory year *t*–1, as determined by the AER

> CPI_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.

In addition, ETSA Utilities can not raise the fixed supply charge for small customers by more than $10 per annum over the course of the next regulatory control period.

4.6.3 Ring fencing and compliance monitoring

Clause 9.29.7 of the NER states that on the AER's assumption of responsibility for the economic regulation of distribution services in South Australia, the guidelines entitled *Operational Ring-fencing Requirements for the SA Electricity Supply Industry: Electricity Industry Guideline No. 9,* dated June 2003[142] will be taken to be distribution ring fencing guidelines issued by the AER under clause 6.17 of the NER. The ring fencing guideline will therefore be regarded as the AER's ring fencing guideline for South Australia.

The guideline sets out specific requirements in regard to: separation of licensed entities, definition of related businesses, compliance procedures, information flows to related businesses, ring fencing waivers and procedures for revising the guidelines. Cost allocation methods prepared by ETSA Utilities that are to be applied in the next regulatory control period were approved by the AER in February 2009.

To the extent that the ESCOSA's reporting guideline does not cover additional matters addressed in this draft decision, such as the incentive schemes discussed in chapters 12, 13 and 14, appendix L of this draft decision sets out reporting requirements. This appendix should be read in conjunction with the ESCOSA's Electricity Industry Guideline No. 4, *Compliance Systems and Reporting*.

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 ETSA Utilities is a weighted average price cap. The applicable WAPC and side constraint formulas are set out in section 4.6 of this draft decision.

> In accordance with clause 6.12.1(19) of the NER, ETSA Utilities 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 F of this draft decision.

[142] Including amendments and substitutions made up to the date the AER assumes that responsibility.

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

5 Opening asset base

5.1 Introduction

This chapter sets out the method used by the AER to determine the closing regulatory asset base (RAB) for ETSA Utilities for the current regulatory control period. The closing RAB 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.[143]

Clause S6.2.1(c)(1) of the NER provides that ETSA Utilities' RAB for the first year of the next regulatory control period must be determined by rolling forward the RAB value (as at 1 July 2005) of $2466 million ($ December 2004).

5.3 ETSA Utilities regulatory proposal

ETSA Utilities proposed an opening RAB for the next regulatory control period of $3011 million as at 1 July 2010.[144] Its proposed opening RAB was derived by taking an opening RAB of $2634 million as at 1 July 2005 and making the following adjustments:[145]

- addition of $762 million for capex incurred during the current regulatory control period (net of disposals and inclusive of contributed assets)
- reduction of $385 million for depreciation based on actual capex
- reduction of $0.3 million reflecting the amount of actual capex above forecast capex for 2004–05
- reduction of $0.2 million reflecting an adjustment for the return on the $0.3 million of capex above forecast for 2004–05
- indexation for actual inflation using the CPI.

ETSA Utilities proposed roll forward of the RAB from 1 July 2005 to 1 July 2010 is detailed in table 5.1.

143 AER, *Final decision, Electricity distribution network service providers, Roll forward model*, June 2008.
144 ETSA Utilities, *Regulatory proposal*, July 2009, p. 234.
145 ETSA Utilities, *Regulatory proposal*, July 2009, p. 234.

Table 5.1: ETSA Utilities 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	2634.4	2726.3	2764.6	2842.5	2927.1
Net capex	149.4	122.5	119.9	176.8	193.2
Regulatory depreciation	–136.1	–150.6	–159.2	–171.8	–185.5
Nominal actual inflation on opening RAB	78.6	66.4	117.3	79.6	76.9
Difference between forecast and actual capex 2004–05					–0.5
Closing balance 30 June	2726.3	2764.6	2842.5	2927.1	3011.0
Inflation rate	2.98%	2.44%	4.24%	2.80%	2.63%

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 234.

ETSA Utilities stated its opening RAB as at 1 July 2005 differs from that contained in the NER due to the conversion of dollar values from December 2004 to June 2005, an under spend of actual capex of $3.4 million in 2004–05, the inclusion of a revaluation of easements, and a correction of a historical modelling error related to ESCOSA's treatment of certain capital contributions. These adjustments are summarised in table 5.2.

Table 5.2: ETSA Utilities proposed 1 July 2005 opening RAB ($m, nominal)

	Adjustments
Opening RAB ($Dec 2004)	2466.2
Revaluation of RAB to June 2005 dollars	35.6
Easement adjustment[a]	116.2
RAB modelling adjustment	16.3
Balance as at 1 July 2005	2634.4

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 234.
(a) ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1: Adjustment of the RAB for the valuation of easements and the correction of a modelling error, p. 46.

5.3.1 Valuation of easements

ETSA Utilities highlighted that the *South Australian Electricity Pricing Order* (EPO) contains an asset schedule which prescribed the initial RAB used in ESCOSA's first regulatory decision for ETSA Utilities.[146] ETSA Utilities claims the EPO also allowed for the inclusion of assets that were not included in the asset schedule into the initial RAB on the basis that they were necessary to enable ETSA Utilities to provide prescribed distribution services. These assets included without limitation, the easements used by ETSA Utilities to provide distribution services.[147]

ETSA Utilities stated that at the time the EPO was developed in 1999, neither it nor the South Australian government held the necessary database to identify the length or location of the easements on which ETSA Utilities' distribution network was located.[148]

ETSA Utilities argued:[149]

> that the State "captured" the value associated with the easements by providing in the EPO for the value of easement assets to be brought into account in future price reviews once there had been an opportunity to undertake a valuation of those assets.

ETSA Utilities also stated that the South Australian government had benefited in the proceeds of the privatisation from the prospect of the subsequent valuation of easements. It also noted the successful bidder for the South Australian government's distribution network assets had the benefit of a 'regulatory commitment' in the EPO that the value of the assets would be amended through a proper valuation process once the data became available.[150]

ETSA Utilities noted that as part of ESCOSA's initial decision setting tariffs for 1999 to 2005, ESCOSA included an allowance of $6 million for easements in ETSA Utilities' RAB.[151] However, ETSA Utilities argued that it was never envisaged when the EPO was promulgated that the initial amount of $6 million was a proper valuation of the totality of distribution network easements.[152] ETSA Utilities claimed that the value of $6 million was taken as the total 'at cost' amount shown in ETSA Corporation's accounts for easements.[153]

ETSA Utilities claimed that the amount of $6 million shown in ETSA Corporation's accounts was not a valuation of all of ETSA Utilities' easements and was not carried out pursuant to any valuation methodology endorsed by the Council of Australian Government agreement for the valuation of electricity infrastructure.[154]

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146 South Australia *Electricity Act 1996, Section 35B, Electricity Pricing Order,* clause 7.3(b), schedule 9.
147 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1: Adjustment of the RAB for the valuation of easements and the correction of a modelling error, p. 3.
148 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 2.
149 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 3.
150 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 3.
151 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 110.
152 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 16.
153 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 14.
154 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 16.

ETSA Utilities proposed an addition to its opening RAB of $116.2 million (calculated by taking the revalued easements of $123.5 million[155] and subtracting the original value of $6 million indexed for inflation to 1 July 2005).[156]

ETSA Utilities noted section 18 (4)(b) of the *National Electricity (South Australia) Act 1996* requires that the AER must, when acting under the *National Electricity (South Australia) Law*, give effect to the provisions of the EPO. Hence, ETSA Utilities argued that the AER is required under clause 7.3(b)(iv) of the EPO to consider afresh the valuation of easements used by ETSA Utilities to provide prescribed distribution services that were not included in the EPO asset schedule.[157] ETSA Utilities considered such a revaluation of easements would also provide for regulatory certainty.[158]

ETSA Utilities listed four developments since ESCOSA's 2005 price determination in relation to its claim for a revaluation of easements:[159]

1. the AER's acceptance of ElectraNet's submission that its opening regulated asset base for the purposes of determining transmission pricing should include, on an historical basis, the costs of compensation paid to acquire easements used for the transmission network
2. the decision of the Australian Competition Tribunal (Tribunal) on an application by ElectraNet against the decision of the AER regarding the inclusion of historical acquisition costs in the 2008–09 to 2012–13 transmission determination
3. comprehensive evidence and analysis prepared by ETSA Utilities of:
    a. the different categories and characteristics of easements used in the distribution network
    b. the proportion of the distribution network located within the different categories of easements
    c. actual compensation costs paid for the categories of easements
    d. statistical information to derive numbers of easements and estimates of acquisition costs where no separate records exist of those matters
4. ETSA Utilities no longer wants the valuation of the easements to occur on a deprival basis and, instead, made its claim based on indexed historical costs.

ETSA Utilities argued that there are no material differences between its entitlement to a valuation of easements under the EPO and the approaches of the AER and the Tribunal in their respective determinations regarding the valuation and inclusion in the RAB of easements used by ElectraNet.

155 ETSA Utilities proposed an indexed historical cost approach for the revaluation.
156 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 45.
157 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 5.
158 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 16.
159 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 5.

5.3.2 ESCOSA treatment of capital contributions

ETSA Utilities claimed that the RAB established by ESCOSA in 1999 contained an error. ETSA Utilities claimed that it was not aware of this error until late in 2004, by which time the opportunity to seek to correct the error was limited given the requirement for ESCOSA to release its 2005 price determination.[160] ETSA Utilities has proposed the AER correct this error by increasing its RAB at 1 July 2005 by $16.3 million.

ETSA Utilities queried whether ESCOSA was allowed to remove certain capital contributions from its RAB in 1999. The EPO provides for a RAB of $2080 million as at 1 July 1999. ESCOSA added $141.0 million for assets that were not in the fixed asset schedule of the EPO but were necessary for ETSA Utilities to provide prescribed services under clause 7.2(e)(iv) of the EPO. It also subtracted $13.5 million related to customer contributions for the year ended 30 June 1999.

ETSA Utilities claimed that under clause 7.2(a)(i)[161] [sic] of the EPO ESCOSA had no legal authority to make the reduction for capital contributions.[162] It also argued that:[163]

> an adjustment for 'contributions' cannot be related to a period prior to the date at which the EPO fixed the opening RAB as at 1 July 1999 - see clause 7.3(b)(i) of the EPO.

ETSA Utilities proposed reinstating the capital contributions removed from its 1 July 1999 RAB. To do this it has indexed the capital contribution amount of $13.5 million (as at 1 July 1999) for inflation to give a value of $16.3 million (as at 1 July 2005).

5.4 Submissions

The Energy Consumers Coalition of South Australia (ECCSA) acknowledged that under the NER, the AER must include in the RAB all capex incurred without assessing whether the amounts are prudent. As a result, the ECCSA stated that there are risks that the RAB could be inflated by regulatory gaming, the effects of which would persist into the future.[164]

The South Australian Council of Social Service (SACOSS) stated that the regulatory framework incentivises the maximisation of the RAB and the minimisation of consumption forecasts to allow greater cost recovery through DUOS charges. As a result, the SACOSS suggested that ETSA Utilities has proposed questionable changes to the RAB. The SACOSS considered that the inclusion of easements in the RAB is premised on a debateable technicality that ETSA Utilities purchased the distribution system lease on the basis that these historical costs would be added to the RAB at some point in the future.[165]

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160 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 48.
161 The AER presumes ETSA Utilities intended to refer to clause 7.2(e)(i) of the EPO.
162 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 48.
163 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, p. 49.
164 ECCSA, *Australian Energy Regulator, SA electricity distribution revenue reset, ETSA Utilities application, a response*, August 2009, p. 16.
165 SACOSS, *Submission to the AER*, August 2009, p. 2.

SACOSS considered that it is unreasonable for ETSA Utilities to be compensated for money that was spent before it owned the business on the basis that there was a handshake assurance during the sale process it would be compensated.[166]

The Council of the Ageing Seniors Voice (COTA) considered the inclusion of a value for easements was equivalent to compensating ETSA Utilities for money that it had not spent, because ETSA Utilities did not own the system when this money was paid.[167]

5.5 Issues and AER considerations

5.5.1 Opening asset value 1 July 2005

5.5.1.1 Valuation of Easements

National Electricity Rules

Schedule 6.2 of the NER requires the AER to apply a specified opening value in respect of ETSA Utilities' RAB for the next regulatory control period. In particular, clause S6.2.1(c)(1) of the NER states that ETSA Utilities' opening RAB for the purpose of the distribution determination is $2466 million. This RAB has been derived from the most recent price determination for ETSA Utilities made by ESCOSA.[168]

The AER considers that the above value is 'locked in', unless an adjustment is required under clause S6.2.1(c)(2) of the NER for any difference between forecast and actual capex[169] or if another piece of legislation were to override the provisions of the NER.

South Australian Electricity Pricing Order

ETSA Utilities cited subsection 18(4) of the *National Electricity (South Australia) Act 1996* which states:

> (4) On or after the relevant day, the AER must, when acting under the National Electricity (South Australia) Law —
>
> (a) comply with the requirements under subsection (5); and
>
> (b) give effect to the provisions of the EPO (as in force from time to time).

ETSA Utilities argued that by virtue of subsection 18(4) of the *National Electricity (South Australia) Act*, the AER is required to observe relevant provisions of the EPO. In addition, subsection 18(6) provides that 'the EPO will be taken to continue to apply as if the AER were the regulator under the EPO.'

166 SACOSS, *Submission to the AER*, August 2009, p. 3.
167 COTA, *ETSA distribution price review*, August 2009, p. 5.
168 This value is the same as that used by ESCOSA in its 2005 pricing determination. See ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, table 9.5, p. 124.
169 ETSA Utilities has not proposed any adjustments of this kind.

The AER notes although the EPO ceased to have direct effect on the regulation of distribution prices on 30 June 2005, the EPO may still have relevance in certain circumstances, specifically, clause 7.3(b)(iv) of the EPO provides that:

> In making a price determination under the Code in respect of ETSA Utilities for any regulatory periods after the subsequent regulatory period, the Regulator must: …
>
> (b) where the value of the assets used by ETSA Utilities is required to be taken into account in making the price determination in respect of the regulatory period immediately after the subsequent regulatory period, use the fixed asset base set out in the Asset Schedule provided that: …
>
> (iv) consideration should also be given to assets that are not included in the Asset Schedule but are necessary to enable ETSA Utilities to provide prescribed distribution services in accordance with good electricity industry practice and the requirements of the Code, the Distribution Code and any other applicable laws including, without limitation, the easements used by ETSA Utilities to provide prescribed distribution services;

As a result of this provision, particularly the definition of 'subsequent regulatory period', the AER considers it may have to give regard to clause 7.3 of the EPO and review the value of ETSA Utilities' easements. However, whether this is an obligation that continues despite the existence of clause S6.2.1(c)(1) of the NER is not clear. In addition, even if the AER is required to consider the value of easements, it is of the view that this does not mean it must undertake a revaluation of easements as ETSA Utilities claimed.

Based on the above considerations, the AER considers it prudent to consider the value ascribed to ETSA Utilities' easements. There are however, a number of different ways the AER could consider this value. One such option is to consider the indexed historical costs provided by ETSA Utilities. Another of the options available to the AER is to consider ESCOSA's valuation of ETSA Utilities' easements under the EPO.

There are several prima facie reasons why it is appropriate for the AER to consider ETSA Utilities' easements on the basis of the analysis performed by ESCOSA, in particular:

- ESCOSA was the original regulator of ETSA Utilities and was familiar with the legislation (that is, the EPO and national electricity code (NEC)) that established the regulatory arrangements for ETSA Utilities.
- ESCOSA gave consideration to the value of ETSA Utilities' easements as part of its 2005 price determination.[170]
- ESCOSA reconsidered the value of ETSA Utilities easements as part of a review of its 2005 price determination.[171]

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170 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005.

- as part of its 2005 price determination and subsequent review, ESCOSA consulted with the South Australian Treasurer as to any representations made by the South Australian government concerning the valuation of easements as of part of the government's sale process of ETSA Utilities. This information includes confidential material.

- under section 7A(4)(a)(i) of the NEL, the AER should have regard to the RAB contained in any previous distribution determination, which, in this case, is ESCOSA's 2005 price determination.

ESCOSA valuation of easements

The AER notes that in ESCOSA's 2005 price determination, ESCOSA decided that the value of ETSA Utilities' easements was $6 million as at 1 July 2005.[172] ESCOSA stated it had chosen this figure because it was consistent with the value used in the price control scheme of the EPO at the time. (This price control scheme was to end on 30 June 2005 with ESCOSA's 2005 price determination to succeed it).

During ESCOSA's price determination process, ETSA Utilities submitted that the value arrived at by ESCOSA was incorrect because it was in conflict with:[173]

- the EPO and the NEC

- the principles for the determination of tariffs which permit a distributor to recover a reasonable rate of return on the asset base used in the provision of distribution network services

- ESCOSA's treatment of other assets that were within the scope of clause 7.2(e)(iv) of the EPO, namely working capital and work in progress (ETSA Utilities considered that there had been a re-evaluation)

- the expectations created by the government at the time of sale.

ESCOSA considered these issues in its 2005 price determination.[174] ESCOSA first had regard to the overarching principles in the NEC concerning the valuation of easements and land as stated in clause 6.10.3(e)(5) of the NEC. ESCOSA considered this clause in order to determine both whether its concept of value was inconsistent with the NEC and, more importantly for present purposes, whether the clause imposed a requirement that it needed to "re-value" ETSA Utilities' easements.

ESCOSA noted that clause 6.10.3(e)(5)(ii) of the NEC did not provide guidance as to whether there was a preference for the value determined by the jurisdictional regulator

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171 ESCOSA, *2005–2010 Electricity Distribution Price Determination, An application by ETSA Utilities for a review pursuant to section 31 of the Essential Services Commission Act 2002, Decision and Reason for Decision*, May 2005.

172 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 110.

173 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 111.

174 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, pp. 111–117.

or a value consistent with the RAB established by the South Australian government.[175] ESCOSA thus considered that this question needed to be resolved by considering the objectives in clause 6.10.2 of the NEC and the other principles in clause 6.10.3 of the NEC.

ESCOSA concluded that the value of easements needed to be consistent with the existing RAB used in the price control scheme of the EPO at the time. This reasoning was based on clause 6.10.2(g) of the NEC which required ESCOSA to give reasonable recognition of pre-existing policies of governments which are DNSP owners regarding distribution asset values, revenue paths and prices.[176]

Moreover, clause 6.10.3(6)(iv)(A) of the NEC required ESCOSA to have regard to:

> relevant previous regulatory decisions made by authorised persons including the initial revenue setting and asset valuation decisions made by a government at a time at which that government was a Distribution Network Owner…

ESCOSA considered that the value of $6 million was assigned by the South Australian government as owner of the DNSP to easements for the 1999–2005 regulatory control period based on the price control scheme adopted for this period.

ESCOSA also considered ETSA Utilities' submission that the amount it paid the South Australian government under the distribution network land lease was the appropriate value to be included in the RAB for easements.

ETSA Utilities' submission did not find favour with ESCOSA because the amount paid under the lease was not necessarily linked to the value of the easements but was commensurate with the bid structure adopted by ETSA Utilities for the overall business. ESCOSA also noted that easements do not generate their own cash flow and that the value ultimately paid represented the value ETSA Utilities had placed on the entirety of the business in its bid. ESCOSA further noted that it had:[177]

> twice confirmed with the South Australian government that there were no records of representations made to bidders that there would be an "upside" in the treatment of value of easements by regulators in the future.

Review of ESCOSA decision

ETSA Utilities made an application for a review of ESCOSA's valuation decision pursuant to section 31 of the *Essential Services Commission Act 2002 (SA)*. As ETSA Utilities' regulatory proposal currently before the AER reiterates matters put before ESCOSA, it is useful to examine the review.

In its application for review, ETSA Utilities argued that ESCOSA's decision contained the following errors:

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[175] ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 112.

[176] ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 113.

[177] ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 117.

- the figure of $6 million was not a complete valuation of the totality of ETSA Utilities' relevant easements
- misconstructions and misapplications of the EPO and the NEC
- inconsistency with the nature and the purpose of the regulatory regime applicable to ETSA Utilities
- inconsistency with the reasonable expectations of potential purchasers created at the time ETSA Utilities was privatised.

ESCOSA considered ETSA Utilities' argument that the easement valuation of $6 million was not a valuation of all relevant easements. However, ESCOSA rejected this notion stating it:[178]

> does not accept that the value included within the initial regulatory asset base was an outcome of an "incomplete process" for valuing easements and substation land. Such a statement implies that the value only relates to a portion of the total amount of easements and land, whereas it is necessarily the case that the value must represent a complete value, albeit one calculated under a different methodology to that promoted by ETSA Utilities…. Ultimately, the purchasers of the electricity distribution business offered and paid an amount for the value it ascribed to that business.

The South Australian Treasurer also joined the proceedings and observed:[179]

> In terms of assessing overall bids, the Government was likely to be completely indifferent to the value included in the bid for Total Rent on land and easements, as the assessment was based on the overall cash consideration for the business as a whole.
>
> The fact that a particular bidder allocated $276.2 million to easements [sic] was a matter for that bidder and implies nothing with regard to the value the Government placed on those particular assets and nothing with regard to the value an independent regulator would apply to those assets in the future.

ESCOSA remained of the view that the amount of $6 million for existing easements, (that is, those easements in existence as at 1 July 1999) assumed within the price control scheme of the EPO was the value for the easements and that the winning bid of did not necessarily reflect their value.[180]

Overall, ESCOSA rejected ETSA Utilities' application on the basis that ETSA Utilities had failed to demonstrate how ESCOSA could be bound by any relevant representations that may have been made by the South Australian government and

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178 ESCOSA, *An application by ETSA Utilities for a review, Decision and Reason for Decision*, May 2005, p. 11.

179 Treasurer of South Australia, *Review of the Essential Services Commission of SA Electricity Distribution Price Determination*, p. 9, in: ESCOSA, *An application by ETSA Utilities for a review, Decision and Reason for Decision*, May 2005, p. 12.

180 ESCOSA, *An application by ETSA Utilities for a review, Decision and Reason for Decision*, May 2005, p. 13.

that, in any event, ESCOSA could not be so bound absent a legislative direction under the EPO.[181]

The AER considers that, for the purposes of clause 7.2(e)(iv) of the EPO and under clause 6.10.3(e)(5)(ii) of the NEC, ESCOSA had the option to revalue ETSA Utilities' easements or to set a value for those easements consistent with the value set in the initial RAB. ESCOSA chose the later approach, which used the value of easements set by the South Australian government in the price control scheme of the EPO at the time. The AER considers that ESCOSA's decision was consistent with clauses 6.10.2(g) and 6.10.3(6)(iv)(A) of the NEC. Notwithstanding these clauses, the AER considers that ESCOSA was under no obligation to revalue ETSA Utilities' easements under the EPO or NEC.

The AER notes that ESCOSA set the value of easements in a manner that was consistent with other assets that were not included in the Asset Schedule of the EPO but were subsequently included by ESCOSA in ETSA Utilities' RAB under clause 7.2(e)(iv) of the EPO. In particular, ESCOSA attributed values to these assets that were consistent with the values for each asset included within the price control scheme applicable under the EPO at the time.[182] In the case of the existing easements, the relevant value was $6 million.

The AER also considers that there was no explicit provision in the bidding process for the South Australian distribution network that required easements to be re-valued post purchase and no regulatory compact to this effect.

Based on the above considerations, the AER had decided that ESCOSA's decision to value ETSA Utilities' easements at $6 million was appropriate under the EPO and NEC.

ETSA Utilities' indexed historical cost valuation of easements

In its regulatory proposal to the AER, ETSA Utilities extrapolated a value for easements based on indexed historical costs.[183] As discussed above, the AER has considered the options for determining the value of the easements and has taken the view that there are sound *prima facie* reasons to adopt an approach based on ESCOSA's assessment of the value of the easements. The AER has then analysed ESCOSA's assessment in depth and considers that the value determined by ESCOSA is appropriate. The AER considers that the $6 million value of easements determined by ESCOSA was consistent with the value used by the South Australian government for easements in the price control scheme of the EPO at the time of privatisation. This process established a fair market value of the business as a whole. On this basis, any attempt to reassign a value to a particular asset class would require a compensating adjustment to other asset classes. Given these circumstances, the AER has not had to consider the detail of ETSA Utilities' valuation approach.

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181 ESCOSA, *An application by ETSA Utilities for a review, Decision and Reason for Decision*, May 2005, p. 32.

182 ESCOSA, *An application by ETSA Utilities for a review, Decision and Reason for Decision*, May 2005, p. 15.

183 ETSA Utilities, *Regulatory proposal*, July 2009, attachment I.1, pp. 2–45.

In their submissions, the SACOSS rejected the notion that easements were intended to be revalued post ETSA Utilities purchase of the network, while the COTA considered any revaluation of easements post purchase as equivalent to compensating ETSA Utilities for money that it had not spent. The AER notes, and has considered, these submissions in its review of ETSA Utilities regulatory proposal.

Australian Competition Tribunal review of the AER's ElectraNet decision

The AER notes ETSA Utilities' reference to the Tribunal's decision with respect to the application by ElectraNet Pty Ltd.[184] The decision of the Tribunal was in relation to the AER's determination of ElectraNet's RAB for the 2008–2013 regulatory control period, in particular, the AER's refusal to make an adjustment to ElectraNet's RAB for easement acquisition costs.

In the ElectraNet case, the Tribunal decided that ElectraNet's easements should be revalued using a historical costs approach and decided to adopt as a proxy for ElectraNet's historical easement acquisition costs based on the oldest valuation available to it. This valuation was contained in a Maloney Field Service (MFS) 1997 report as updated by a MFS report in 2000 and adjusted in a later 2002 report by Meritec.[185] The Tribunal noted that the 1997 MFS valuation was exhibited in a June 2000 Information Memorandum prepared for potential investors and was exhibited for them at the time ElectraNet was being privatised. The Tribunal reasoned that this:[186]

> may well have influenced potential investors when they formed their 'reasonable expectations' of an asset base revaluation referred to in the letter from the ACCC to ElectraNet as enshrined in Chapter 11 of the Rules. Those expectations are integral to clause 11.6.13(b) of the Rules and to incorporating an opportunity cost of capital in the RAB which encourages efficient investment for the long term benefit of consumers, consistent with the national electricity objective and the revenue and pricing principles.

The AER has been unable to find evidence that similar representations were made to the bidders for ETSA Utilities by the South Australian government. In the absence of such evidence the AER considers that the Tribunal's ElectraNet decision is not applicable in the present circumstances. Even if it were applicable and the AER applied a similar principle of seeking out the oldest valuation of ETSA Utilities easements, in the present circumstances, this valuation would be the $6 million determined by the South Australian government and was the value adopted by ESCOSA in its 2005 price determination.

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[184] ACT, *Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3* (30 September 2008), para 112.

[185] ACT, *Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3* (30 September 2008), para 221–223.

[186] ACT, *Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3* (30 September 2008), para 225.

5.5.1.2 ESCOSA's adjustment for capital contributions

ESCOSA removed $13.5 million of customer contributions from ETSA Utilities fixed asset base as at 1 July 1999.[187] In doing so, ESCOSA relied on clause 7.2(e)(iii) of the EPO that states:

> the portion of any network augmentation or extension directly funded by customer contributions (in accordance with the Distribution Code) must not be included as an addition to the fixed asset base under clause 7.2(e)(i).

ETSA Utilities has argued that ESCOSA should not have deducted these capital contributions as they relate to a time before the EPO took effect and therefore ESCOSA had no authority to make the deduction. In particular, ETSA Utilities considers that clauses 7.2(e)(i) and 7.3(b)(i) of the EPO allows ESCOSA to only adjustment the fixed asset base for the various matters listed in those clauses (including for capital contributions) 'since the *Commencement Date*', which was 11 October 1999.[188]

In response to a query by the AER, ESCOSA noted it had replicated the calculation of the initial asset base as determined by the Treasurer[189] and that the Treasurer's calculation included the adjustment for capital contributions in the initial asset base.[190] ESCOSA also noted that these calculations were shared with ETSA Utilities prior to the release of ESCOSA's 2005 draft decision and that ETSA Utilities had not raised the capital contributions adjustment as an issue with ESCOSA.

Clause 7.3(b)(i) of the EPO requires the AER to 'reasonably determine' adjustments that should be made to the fixed asset base since the 'commencement date' (being 11 October 1999). It would appear to be reasonable to rely on the adjustments made by ESCOSA previously. To do otherwise, would suggest that the AER might have to reconsider all adjustments that have been made by ESCOSA.

Based on the above considerations, the AER considers that ESCOSA's decision regarding ETSA Utilities initial asset base should prevail. The AER therefore rejects ETSA Utilities' proposal that the capital contributions deducted from its initial asset base be reinstated into its RAB as at 1 July 1999.

5.5.1.3 Conclusion

Based on the considerations above, the AER has not accepted ETSA Utilities' proposed opening RAB as at 1 July 2005 of $2634 million. As discussed above, the AER has rejected ETSA Utilities proposed increase in the value of its easements.

The AER has accepted the value of $2502 million as being the opening RAB as at 1 July 2005. This value is based on the opening RAB proposed by ETSA Utilities:

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187 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, p. 109.

188 The definition of *'Commencement Date'* is given by clause 1.8(a) of the EPO as 11 October 1999.

189 South Australian Electricity Reform and Sales Unit, submission to the ACCC on the EPO, 11 August 1999.

190 ECSOCA, email to the AER, 15 October 2009.

- less $116.2 million associated with ETSA Utilities' revaluation of its easements[191]
- less $16.3 million of capital contributions that ETSA Utilities had reinstated into its RAB.[192]

5.5.2 Use of inflation

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.[193] ETSA Utilities has applied the Australian Bureau of Statistics (ABS) weighted average of eight capital cities, March to March annual CPI.[194] This was consistent with the weighted average price cap used by ESCOSA for the current regulatory control period.[195]

Actual data for March to March CPI is contained in table 5.3. These CPI rates will apply to ETSA Utilities for the purposes of the RFM. With the exception of the CPI for 2008–09, the other CPI figures match those used by ETSA Utilities. As the March to March data for 2009–10 is unavailable at the time of this draft decision, the AER will apply the forecast rate of 2.63 per cent used by ETSA Utilities in its RFM. This figure will be updated for the final decision.

Table 5.3: 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 Removal of metering assets

As discussed in chapter 2, the AER has reclassified certain metering services as alternative control services. Due to this reclassification, the metering assets associated with these alternative control services need to be removed from the opening RAB for standard control services. Based on advice received from ETSA Utilities, the AER has accepted the value of these metering assets to be $82.6 million as at 1 July 2010 and has reduced the RAB for standard control services by this amount.[196] The reduction in ETSA Utilities' opening RAB is allowed under clause S6.2.1(e)(7) of the NER.

5.5.4 Roll forward methodology

In accordance with the RFM, the closing RAB (nominal) for each year of the current regulatory control period is calculated by:

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[191] ETSA Utilities, *Regulatory proposal*, July 2009, p. 234.
[192] ETSA Utilities, *Regulatory proposal*, July 2009, p. 234.
[193] NER, clause 6.5.1(e)(3).
[194] ETSA Utilities, *Regulatory proposal*, July 2009, p. 233.
[195] ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, pp. 107–108.
[196] ETSA Utilities, email to the AER, Issue no: AER.EU.42, 13 November 2009.

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 2005–10 ESCOSA 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.

Applying the RFM, ETSA Utilities derived an opening RAB as at 1 July 2010 of $3011 million as detailed in table 5.1.

The AER has reviewed ETSA Utilities' proposed opening RAB and the cost inputs to the RFM for the current regulatory control period and has cross checked these against ETSA Utilities regulatory accounts. The AER is satisfied that ETSA Utilities has completed the RFM in accordance with the requirements of the NER. However, as noted in section 5.5.1, the AER has not allowed the inclusion of ETSA Utilities' proposed easement re-valuation and the reinstatement of capital contributions. The AER has removed these adjustments from the opening RAB (as at 1 July 2005) proposed by ETSA Utilities. Given the reclassification of metering assets as alternative control services, the value of these assets has also been removed from the RAB.

For the purposes of this draft decision, the AER has applied an opening RAB for ETSA Utilities of $2768 million as at 1 July 2010. This value is used as an input to the PTRM for the purposes of determining ETSA Utilities' annual revenue requirement during the next regulatory control period.

5.5.5 RAB roll forward for the 2015–20 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 an overspend in capex, 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.

AER considerations

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
>
> (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 ETSA Utilities. ETSA Utilities did not address this matter in its regulatory proposal.

The AER assesses the scope and cost of the capex program and ETSA Utilities' investment needs in chapter 7 of this draft decision. The AER also considers whether ETSA Utilities' 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 ETSA Utilities to seek out efficiencies wherever possible in its 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 incentive to ETSA Utilities.

5.6 AER conclusion

The RAB roll forward calculations for ETSA Utilities are set out in table 5.4 and provide for an opening RAB of $2768 million for standard control services for the next regulatory control period (as at 1 July 2010).

Table 5.4: AER conclusion on ETSA Utilities' opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB	2501.8	2590.2	2625.7	2698.2	2770.1
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	149.4	122.5	119.9	176.5	193.2
Straight–line depreciation (adjusted for actual CPI)	61.0	87.1	47.4	104.6	111.9
Closing RAB	2590.2	2625.7	2698.2	2770.1	2851.4
Difference between actual and forecast capex for 2004–05					–0.3
Return on difference					–0.2
Removal of metering assets					–82.6
Opening RAB at 1 July 2010					2768.4

(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.

The AER will update the roll forward of ETSA Utilities' RAB with actual capex for 2008–09, and the most recent forecast of capex and actual CPI for 2009–10 for its final decision.

5.7 AER draft decision

In accordance with clause 6.12.1(6) of the NER, the total opening RAB for ETSA Utilities as at 1 July 2010 is $2768.4 million for standard control services.

In accordance with clause 6.12.1(18) of the NER, the AER will 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 whether ETSA Utilities' demand 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 and whether ETSA Utilities' energy sales forecasts are appropriate inputs to the post–tax revenue model (PTRM).

The AER's assessment of ETSA Utilities' demand forecasts is focussed on the expected summer and winter peak demands, energy sales and customer numbers over the next regulatory control period. Peak 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. Energy sales forecasts (measured in GWh) are used to determine the amount of electricity transported over a period of time and to convert building block revenues to prices in the PTRM. Energy sales forecasts are also a key input into determining X factors under weighted average price cap regulation.[197] Customer number forecasts are an important input into peak demand and energy sales forecasts, and are used in determining weighted average price caps and average price caps.

6.2 Regulatory requirements

ETSA Utilities is required to provide realistic demand forecasts 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) of the NER. Clause 6.12.1(10) of the NER requires the AER to make a decision on appropriate amounts, values or inputs including energy consumption and customer number forecasts, which are inputs to the PTRM.

6.3 ETSA Utilities regulatory proposal

ETSA Utilities based its growth related capex program primarily on forecasts of peak demand at 10 per cent probability of exceedence (PoE).[198]

ETSA Utilities' forecasts of energy sales volumes, taken in conjunction with revenue requirements, determine distribution prices for its customers.[199]

ETSA Utilities forecast peak demand on its network over the next regulatory control period using global (at network level, or top down) and spatial (at zone substation

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197 This is because the AER must take the notional building block requirement and convert this into a weighted average price cap or average price cap based on energy sales growth forecasts.

198 Summer peak demand specified at 10 per cent PoE means that the probability of this maximum demand being exceeded is 10 per cent, or on average one in ten years.

199 ETSA Utilities, *Regulatory proposal*, July 2009, p. 65.

level, or bottom up) forecasts.[200] The global peak demand forecast is used to provide a consistency check against the spatial demand forecasts.[201]

ETSA Utilities' network has been summer peaking in the current regulatory control period and is forecast to remain so in the next regulatory control period.[202] ETSA Utilities' forecasts of peak demand at 10 per cent PoE, energy sales and customer numbers are provided in table 6.1.

Table 6.1: ETSA Utilities' energy sales, peak demand and customer number forecasts

	2010–11	**2011–12**	**2012–13**	**2013–14**	**2014–15**	**Average annual growth 2010–15**
Energy sales (GWh)	10 977	10 989	10 900	10 687	10 596	–0.7%
Network peak demand 10% PoE (MW) – including major customers	3129	3227	3358	3434	3522	3.0%
Customer numbers	828 162	838 160	846 778	854 779	863 230	1.1%

Source: ETSA Utilities, RIN pro forma 2.3.8 (confidential); and ETSA Utilities, response to the AER, 14 September 2009, Issue number AER.EU.23.

ETSA Utilities engaged the National Institute of Economic and Industry Research (NIEIR) to develop forecasts of global peak demand, energy sales and customer numbers for the next regulatory control period.[203] ETSA Utilities stated that the global level forecasts have been developed by NIEIR using rigorous processes, with additional supporting analysis undertaken by Maunsell Australia Pty Ltd (Maunsell).[204]

ETSA Utilities engaged PB Power to review its spatial demand forecasting approach. PB Power concluded that the demand forecast methodology was a generally accepted, effective and historically proven method.[205]

6.3.1 Key drivers

ETSA Utilities identified the following key drivers of peak demand and energy sales on its network:[206]

- the outlook for the South Australian economy

200 ETSA Utilities, *Regulatory proposal*, July 2009, p. 90.
201 ETSA Utilities, *Regulatory proposal*, July 2009, p. 91.
202 ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8, confidential.
203 ETSA Utilities, *Regulatory proposal*, July 2009, p. 65.
204 ETSA Utilities, *Regulatory proposal*, July 2009, p. 65.
205 ETSA Utilities, *Regulatory proposal*, July 2009, p. 100.
206 ETSA Utilities, *Regulatory proposal*, July 2009, p. 65.

- broad suites of government energy efficiency policies including the Carbon Pollution Reduction Scheme (CPRS)
- greenhouse and demand management strategies
- residential customer growth, housing stock and appliance purchase and usage patterns
- growth in business demand and sales driven by specific factors within individual business sectors, including significant major projects such as the Adelaide desalination plant.

6.3.2 Methodology

ETSA Utilities stated that its demand forecasts were based on an April 2009 economic forecast and incorporate the effects of the proposed delay in the introduction of the CPRS to July 2011. However, the forecasts do not incorporate the effects of energy initiatives announced in the May 2009 Federal Budget.[207]

6.4 Submissions

The AER received five submissions addressing ETSA Utilities' demand forecasts, from SA Water, Business SA, the Council On the Ageing Seniors Voice (COTA), the South Australia Council of Social Service (SACOSS) and the Energy Consumers Coalition of South Australia (ECCSA). Each of these submissions addressed the issue of energy consumption forecasts and they are considered in section 6.6.2.

6.5 Consultant review

In April 2009, the AER engaged Electricity Supply Industry Planning Council (ESIPC) to assist it in reviewing ETSA Utilities' forecasts and forecast methodologies for peak demand and energy sales in the next regulatory control period. The ESIPC was dissolved on 30 June 2009, with most of its functions assumed by AEMO from 1 July 2009. The transfer of responsibilities to AEMO included ESIPC's undertaking to report to the AER on ETSA Utilities' demand and energy sales forecast.

The AER also engaged MMA to review ETSA Utilities' customer numbers forecasts and forecast methodology, since this part of the review fells outside of ESIPC's terms of engagement. MMA's review of ETSA Utilities' customer number forecasts followed a similar process to the review of peak demand and energy sales.

AEMO reviewed the forecasts and methodologies described within ETSA Utilities' regulatory proposal, and sought additional information. AEMO undertook the following tasks:[208]

- provide an independent view of ETSA Utilities' annual energy sales by customer category for years 2010–11 to 2014–15 and apportion these to tariff categories

[207] ETSA Utilities, *Regulatory proposal*, July 2009, p. 65.
[208] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009.

- provide an independent view of state–wide distribution network peak demand at the 10 per cent and 50 per cent PoE levels for years 2010–11 to 2014–15 and reconcile these with individual transmission connection point peak demand forecasts submitted by ETSA Utilities

- review the reasonableness of ETSA Utilities' approach and input assumptions used in generating its forecasts

- test the sensitivity of AEMO's forecasts to changes in input assumptions, including using ETSA Utilities' input assumptions as the basis for one of the sensitivities

- identify and comment on the reasons for any differences between ETSA Utilities' and AEMO's sales and network–wide peak demand forecasts.

MMA undertook the following tasks:[209]

- provide a review of ETSA Utilities' approach and methodology used in forecasting customer numbers

- identify and comment on the reasonableness of ETSA Utilities' customer number forecasts.

6.6 Issues and AER considerations

The AER has reviewed ETSA Utilities' regulatory proposal, submissions and analysed AEMO's and MMA's findings and recommendations regarding ETSA Utilities' peak demand, energy sales and customer number forecasts.

6.6.1 Global and spatial peak demand forecasts

6.6.1.1 ETSA Utilities regulatory proposal

The global peak demand forecast is used to provide a consistency check against the spatial demand forecasts.[210] ETSA Utilities' forecasts of peak demand at 10 per cent PoE, energy sales and customer numbers are provided in table 6.1.

Actual demand outcomes for ETSA Utilities during the current regulatory control period are presented in table 6.2. Table 6.2 also shows that ETSA Utilities' summer peak demand over the period 2005–06 to 2007–08 was consistently lower than the level forecast at 10 per cent PoE. This result is not unexpected, given that summer peak demand specified at 10 per cent PoE means that the probability of this peak demand being exceeded is 10 per cent, or that it will be exceeded, on average, only once in ten years.

[209] MMA, *Review of ETSA Utilities customer number forecasts for the 2010 to 2015 price review*, 21 September 2009, p. 1.
[210] ETSA Utilities, *Regulatory proposal*, July 2009, p. 91.

Table 6.2: ETSA Utilities' actual energy sales, peak demand and customer numbers 2005-06 to 2007–08

	2005–06	2006–07	2007–08
Network maximum demand (10% PoE) - 2005 ESCOSA approved forecast (MW)	3037	3116	3196
Network peak demand – actual (MW)	2633	2563	2847
Variation	–13.3%	–17.7%	–10.9%

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8, confidential.

Spatial forecasts

ETSA Utilities noted that its internally produced spatial demand forecasts consist of three independent demand forecasts spanning 10 years at transmission connection point, zone substation and high voltage feeder levels. These three forecasts are updated in April every year and are reconciled with each other using diversity factors at different levels to ensure their consistency.[211] The spatial demand forecasts are aggregated and then compared against NIEIR's global peak demand forecast as a consistency check.

ETSA Utilities provided an outline of its spatial peak demand forecasting process, which included the following steps:

- develop three independent demand forecasts at the transmission connection point, zone substation and high voltage feeder levels
- use recent historical peak demand data to derive the trend in demand growth at the transmission connection point, zone substation and high voltage feeder levels
- extrapolate these growth trends to forecast future demand, taking into account specific local customer driven changes and spot loads impacts
- incorporate network demand management impacts into relevant spatial demand forecasts[212]
- reconcile the three independent forecasts using diversity factors[213]
- check the consistency of the forecast by aggregating the spatial peak demand forecast and comparing it to NIEIR's global peak demand forecast.[214]

Global forecasts

ETSA Utilities provided a high level outline of NIEIR's peak demand forecasting process, which included the following steps:[215]

211 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 90–91.
212 ETSA Utilities, *Regulatory proposal*, July 2009, p. 77.
213 ETSA Utilities, *Regulatory proposal*, July 2009, p. 90.
214 ETSA Utilities, *Regulatory proposal*, July 2009, p. 93.

- separate annual peak demand into weather sensitive demand and weather insensitive demand

- identify key drivers of weather sensitive and weather insensitive peak demand such as real output by industry, population growth, weather conditions and electricity prices

- use an econometric model to quantify the relationship between annual changes in key drivers and peak demand

- produce forecasts for key drivers such as real output by industry, population growth, weather conditions and electricity prices (these variables are used as inputs into the econometric equation to produce point forecasts of global peak demand)

- employ 'bootstrapping', a simulation method which involves generating a large number of synthetic sequences of temperature and the residual from their historical observations. These synthetic sequences are then fed into the estimated demand temperature equations to generate synthetic sequences of demand at 10 per cent, 50 per cent and 90 per cent levels of PoE.

ETSA Utilities provided an outline of NIEIR's energy sales forecasting process, which included the following steps:[216]

- separately forecast annual energy sales to residential, business and major business customers

- disaggregate business sales into industries according to Australian Standard Industrial Classification (ASIC)

- identify key drivers of energy sales for business and residential customers such as real output by industry, population growth, weather conditions and electricity prices

- quantify the relationship between annual changes in key drivers and energy sales for business and residential categories using an econometric model

- use an industry based model to account for economic growth in South Australia and the structure of economic growth in South Australia on an industry basis

- produce annual energy sales forecasts for business and residential customers by inputting NIEIR's projections of the key drivers into the forecast models

- forecast annual energy sales to major business customers based on expected business closures and new starts

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215 ETSA Utilities, *Regulatory proposal*, July 2009, attachment D.2 NIEIR peak demand forecast, pp. 30–32.

216 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 78–83 and attachment D.2 NIEIR peak demand forecast, pp. 24–27.

- quantify the effects of greenhouse policy, climate change, energy efficiency programs, embedded generation and demand management on energy sales and incorporate these effects into the forecast.

6.6.1.2 Consultant review

Spatial peak demand forecasts

AEMO reviewed ETSA Utilities' data sources and approach to compiling its spatial peak demand forecasts at three different levels within the distribution network and its approach to reconciling these forecasts with one another. AEMO considered that this was a sound approach that offered a self-checking mechanism to ensure the forecasts were internally consistent and that consistent data had been used in the preparation of the forecasts.[217]

AEMO evaluated ETSA Utilities' spatial peak demand forecasts at connection point level by reconciling them with AEMO's global peak demand forecasts. AEMO identified two sets of diversity factors at 10 per cent and 1 per cent PoE level, observed during the 2009 summer heatwaves.[218] The two diversity factors were applied to ETSA Utilities' transmission connection point peak demand forecasts and compared with AEMO's 10 per cent and 2 per cent PoE[219] global peak demand forecasts respectively.[220] The results are presented in table 6.3.

Table 6.3: Diversified transmission connection point demands and distribution network demand

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Diversified connection point peak demands at 10% PoE (MW)	3062.7	3173.2	3280.3	3370.6	3461.8	3544.0
AEMO base case 10% PoE global peak demand (MW)	3156.0	3314.6	3358.3	3456.9	3535.3	3625.4
Differences (MW)	–93.3	–141.4	–78.0	–86.3	–73.5	–81.4
Variation	–3.0%	–4.3%	–2.3%	–2.5%	–2.1%	–2.2%
Diversified connection point peak demands at 1% PoE (MW)	3266.7	3386.9	3503.0	3597.9	3695.7	3784.0
AEMO base case 2% PoE global peak demand (MW)	3326.0	3484.6	3538.3	3636.9	3725.3	3825.4
Differences (MW)	–59.3	–97.7	–35.3	–39.0	–29.6	–41.4
Variation	–1.8%	–2.8%	–1.0%	–1.1%	–0.8%	–1.1%

Source: AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 56–59; ETSA Utilities, *Regulatory Proposal*, July 2009, RIN pro forma 2.3.8, confidential.

217 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 60.

218 A diversity factor represents the ratio of demand at a particular connection point at the time of the network-wide peak to the outright peak demand occurring at that point.

219 AEMO indicated that 1 per cent forecasts were not available. AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. XII.

220 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 58–59.

AEMO found that the connection point forecasts, adjusted for diversity factors experienced at the 10 per cent PoE demand level, were broadly consistent with AEMO's peak demand forecasts and lie towards the bottom of the high:low range predicted under the three economic scenarios. The adjusted connection point forecasts are on average around 90 MW below AEMO's base case 10 per cent PoE forecasts. AEMO considered this to be a tolerable discrepancy and within the range of error that might be associated with inherent variability of load diversity across various points within the network. Similarly, ETSA Utilities' connection point forecasts after adjusting for diversity factors observed at the time of the 1 per cent PoE peak demand are also broadly in line with AEMO's 2 per cent PoE base case global peak demand forecasts.[221]

AEMO concluded that ETSA Utilities' transmission connection point forecasts were reasonable.[222]

Global peak demand forecasts

AEMO conducted a review of ETSA Utilities' global peak demand forecasts, the underlying forecasting model and the input assumptions.

Review of input assumptions

AEMO found that ETSA Utilities':[223]

- projected cumulative Australian GDP growth is 5.6 per cent lower compared to the AEMO forecasts over the period 2008–09 to 2014–15
- projected cumulative South Australia GSP growth is 12.9 per cent lower compared to the AEMO forecasts over the period 2008–09 to 2014–15
- projected cumulative average retail electricity price growth is 23.8 per cent higher compared to the AEMO forecasts over the period 2008–09 to 2014–15.

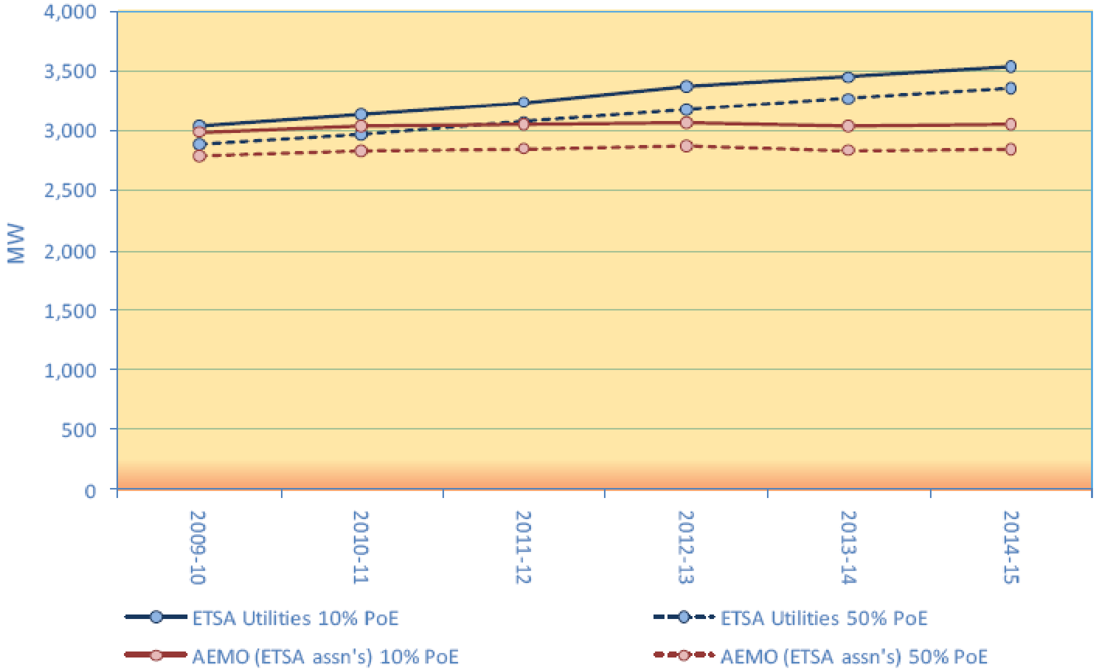
AEMO also considers that in recognition of the possibility that ETSA Utilities' 'Beat the Peak' direct load control program will continue and grow modestly over time, a small downward adjustment, amounting to around 5 to 15 MW over the next regulatory control period, to ETSA Utilities' peak demand forecasts should be included in the peak forecasts.

Review of underlying forecasting model

AEMO reviewed ETSA Utilities' underlying global peak demand forecast model by comparing ETSA Utilities' global peak demand forecasts with equivalent forecasts prepared by AEMO using ETSA Utilities' input assumptions. The results are presented in figure 6.1.

[221] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 59–60.
[222] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 60.
[223] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 19–28.

Figure 6.1: Global peak demand forecasts



Source: AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 50.

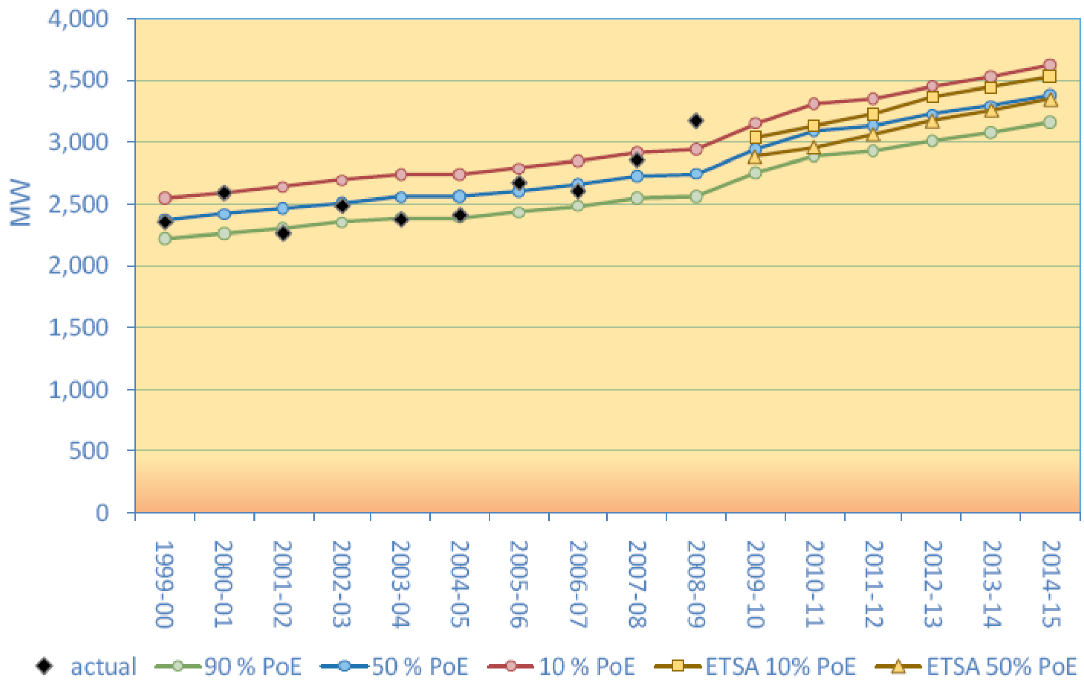
AEMO found that ETSA Utilities' global peak demand model produced much higher forecasts than AEMO's model using the same set of input assumptions. AEMO stated that ETSA Utilities was unable to provide sufficient detail on the model for AEMO to comment in depth on the reasons for the discrepancies in the forecasts.[224]

Review of actual forecasts

AEMO compared the forecasts generated by the two forecast models at the 10 per cent and 50 per cent PoE levels. The results of this comparison, together with actual demand for 1999–2000 to 2008–09, are presented in figure 6.2.

[224] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 50.

Figure 6.2: Comparison of global peak demand forecasts produced by ETSA Utilities and AEMO



Source: AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 56.

AEMO found that the two sets of forecasts are reasonably close for all years throughout the forecast period. AEMO considered that this is a surprising result given the very different economic assumptions underlying the two sets of forecasts. ETSA Utilities' 10 per cent PoE forecasts show compounding growth of 3.1 per cent between 2009–10 and 2014–15 compared with AEMO's forecasts which show growth of 2.8 per cent. AEMO's 10 per cent PoE demand forecast for the 2014–15 summer are 93 MW above ETSA Utilities' forecast.[225]

6.6.1.3 Issues and AER considerations

Spatial peak demand forecast

The AER understands that ETSA Utilities' internally produced spatial peak demand forecasts largely underpin its network capacity planning and consequently its capex program over the regulatory control period. The AER agrees with AEMO's conclusion that ETSA Utilities' spatial peak demand forecast methodology is reasonable, based on the reconciliation of three levels of independent demand forecasts to ensure consistency.

The AER agrees with AEMO's conclusion that ETSA Utilities' spatial peak demand forecasts are reasonable, as the discrepancies between ETSA Utilities' diversified transmission connection point demands and AEMO's global peak demand are within a tolerable range. The AER understands that these discrepancies are mainly driven by the differences between the diversity factors used by the two organisations in deriving

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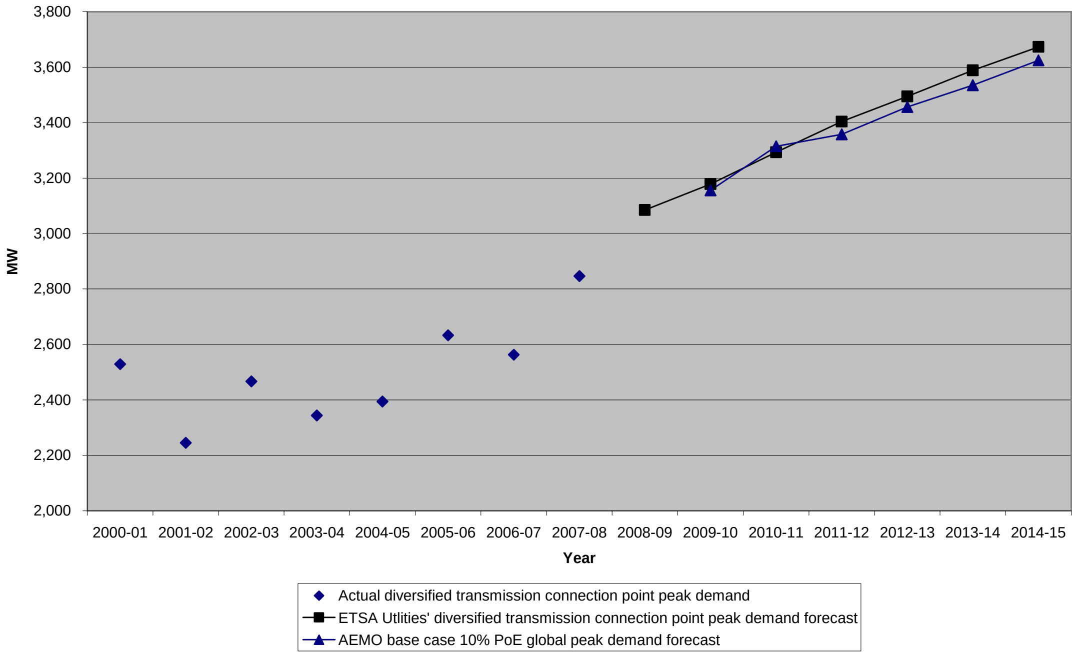
[225] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 56.

the diversified transmission connection point demands.[226] The AER therefore compared ETSA Utilities' diversified transmission connection point demands derived using its own diversity factors with AEMO's base case 10 per cent PoE global peak demand forecasts. The results are presented in figure 6.3.

Figure 6.3: Comparison between ETSA Utilities' diversified transmission connection point demands and AEMO's base case 10 per cent PoE peak demand forecasts



Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8, confidential; and AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 44.

The AER considers the two forecasts are broadly in line, with ETSA Utilities' diversified transmission connection point demands around 33 MW (1 per cent) on average higher than AEMO's global peak demand forecasts over the next regulatory control period. The AER also notes that ETSA Utilities' forecasts of diversified transmission connection point demands are consistent with outcomes from the current regulatory control period, in that the forecasts reflect a reasonable continuation of historical trend.

Global peak demand forecast

The AER understands that ETSA Utilities used NIEIR's global peak demand forecast as a consistency check on the reasonableness of the spatial demand forecasts, but not for network planning purposes.

The AER acknowledges that there appear to be substantial differences between AEMO and NIEIR's underlying forecast models, and that NIEIR's model appears to produce higher global peak demand forecasts when using the same input assumptions. However, the AER agrees with AEMO's conclusion that despite the differences

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226 The AER notes that ETSA Utilities' forecast weighted average diversity factors across transmission connection points are generally higher compared to that assumed by AEMO.

between the two underlying models, they produce similar forecasts. To confirm this, the AER compared NIEIR's global forecasts against AEMO's forecasts, and found the two sets of forecasts are reasonably close over the next regulatory control period, with the former on average 124.1 MW (3.8 per cent) lower than the latter.[227]

6.6.1.4 AER conclusion

Based on AEMO's advice and its own analysis the AER considers that the global and spatial peak demand forecasts provided by ETSA Utilities are 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.

6.6.2 Energy sales forecasts

ETSA Utilities regulatory proposal

ETSA Utilities' forecasts of peak demand at 10 per cent PoE, energy sales and customer numbers are provided in table 6.1.

Actual demand outcomes for ETSA Utilities during the current regulatory control period are presented in table 6.4.

Table 6.4: ETSA Utilities' actual energy sales 2005-06 to 2007–08

	2005–06	2006–07	2007–08
Energy sales – 2005 ESCOSA approved forecast (base) (GWh)	10 509	10 690	10 869
Energy sales – actuals (GWh)	10 954	11 259	11 344
Variation	4.2%	5.3%	4.4%

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8, confidential.

Submissions

SA Water stated that due to the high level of uncertainty surrounding the introduction of the CPRS, consideration of the impact of the CPRS on energy sales forecasts is inappropriate at this time.[228]

Business SA stated that it is sceptical about ETSA Utilities' energy consumption growth forecast of –1.1 per cent over the next regulatory control period, as the forecast is significantly different from the forecast provided by the ESIPC. Business SA stated that ETSA Utilities appears to be overly optimistic in forecasting the fall in electric hot water supply due to the ban on the replacement of electric hot water storage systems. Business SA is also concerned that ETSA Utilities does not appear to have fully accounted for the strong growth in residential electricity sales and peak demand due to air conditioner penetration in its forecasts. Business SA submitted that

[227] Calculated based on ETSA Utilities, *Regulatory Proposal*, July 2009, RIN pro forma 2.3.8, confidential; and ETSA Utilities, response to the AER, 14 September 2009, issue number: AER.EU.23.

[228] SA Water, *SA Water submission on ETSA Utilities regulatory proposal*, 28 August 2009, p. 2.

if energy consumption is higher than forecast in the regulatory proposal, electricity bills for small business will rise even more than the 10 per cent a year increases proposed by ETSA Utilities in the next regulatory control period.

The COTA stated that ETSA Utilities' energy consumption forecasts are underestimated, on the basis that South Australia has a large ageing population, the majority of which do not waste resources and therefore have limited capacity to make substantial energy savings.[229]

The SACOSS stated that the residential energy sales forecasts used by ETSA Utilities are not transparent and appear to be inconsistent with those of other bodies such as the ESIPC. The SACOSS stated that ETSA Utilities' forecast of a fall in residential sales is unreasonable because:[230]

- based on historical data, overall electricity consumption has continued to grow slowly, indicating a strong tendency for electricity consumption to recover from price shocks
- ETSA Utilities has only accounted for demand reductions as a result of energy efficiency programs and appears to have discounted the overall increase in demand as a result of increase in usage of appliances when forecasting residential energy sales.

The SACOSS stated that ETSA Utilities' low energy sales forecast is a response to the incentive embedded in the regulatory framework to minimise energy sales forecasts in order to drive up prices.[231]

The ECCSA stated that there is a mismatch between ETSA Utilities' and ESIPC's demand forecasts, in that ETSA Utilities' peak demand forecast is higher and its energy sales forecast is lower compared to ESIPC's forecasts. It stated that it supports the AER in securing independent assessment of ETSA Utilities' forecast demand growth.[232]

Consultant review

AEMO provided a report to the AER on ETSA Utilities' demand and energy sales forecast. The AEMO process involved reviewing the forecasts and methodologies described within ETSA Utilities' regulatory proposals, and seeking additional information as required.

As shown in figure 6.4, AEMO found that ETSA Utilities' energy sales forecasts over the next regulatory control period are significantly lower than AEMO's energy sales forecasts.

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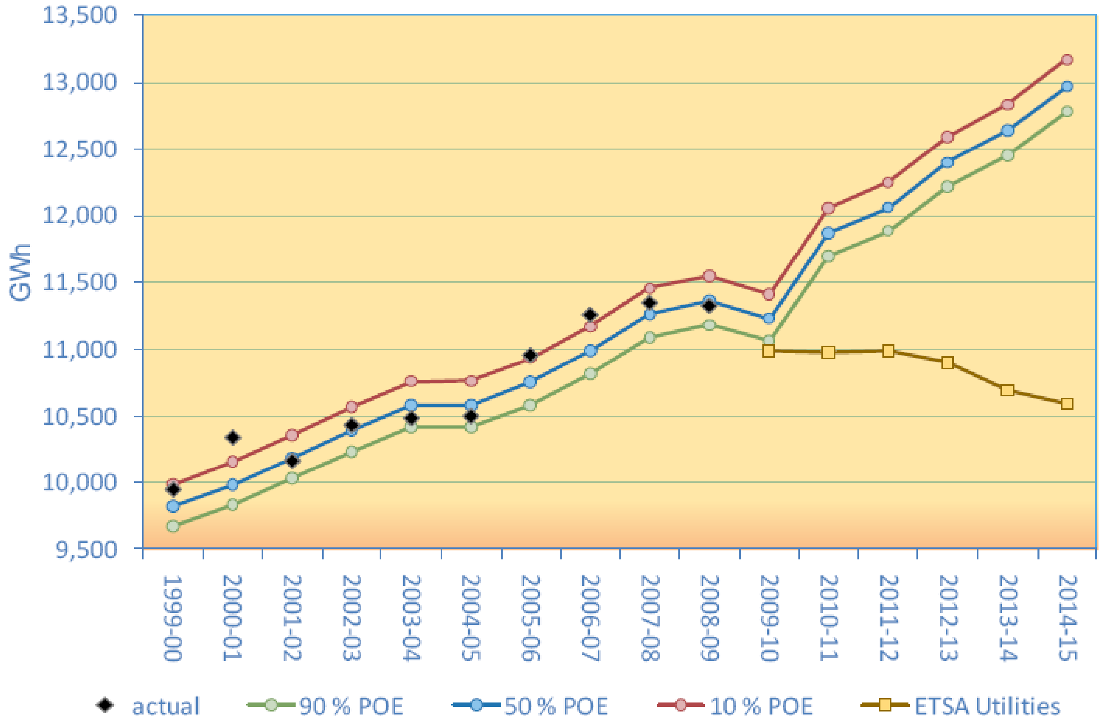
[229] COTA, *ETSA distribution price review*, August 2009, p. 2.
[230] SACOSS, *Submission to the AER*, August 2009 pp. 6–9.
[231] SACOSS, *Submission to the AER*, August 2009, pp. 6–10.
[232] ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 63–65.

Figure 6.4: Comparison of energy sales forecasts by ETSA Utilities and AEMO



Source: AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 53.

AEMO found that its:[233]

- business sector forecasts show average annual growth of 3.5 per cent to 2014–15 compared with ETSA Utilities' forecast average growth of –0.1 per cent
- residential sector sales forecasts show average annual growth of 1.1 per cent compared with ETSA Utilities' average growth rate of –2.5 per cent
- water heating forecasts show average annual growth of –3.5 per cent compared with ETSA Utilities' forecast average annual growth of –10.8 per cent
- forecast of total sales show average annual growth of 2.9 per cent over 2009–10 and 2014–15 compared with ETSA Utilities' forecast average annual growth of –0.7 per cent.

AEMO considered that the differences between the two energy sales forecasts may reflect a combination of factors, including differences in:[234]

- underlying forecasting models relied upon by each organisation
- forecasts of key drivers, including the assumed economic outlook and future retail electricity prices

233 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 54.
234 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 17.

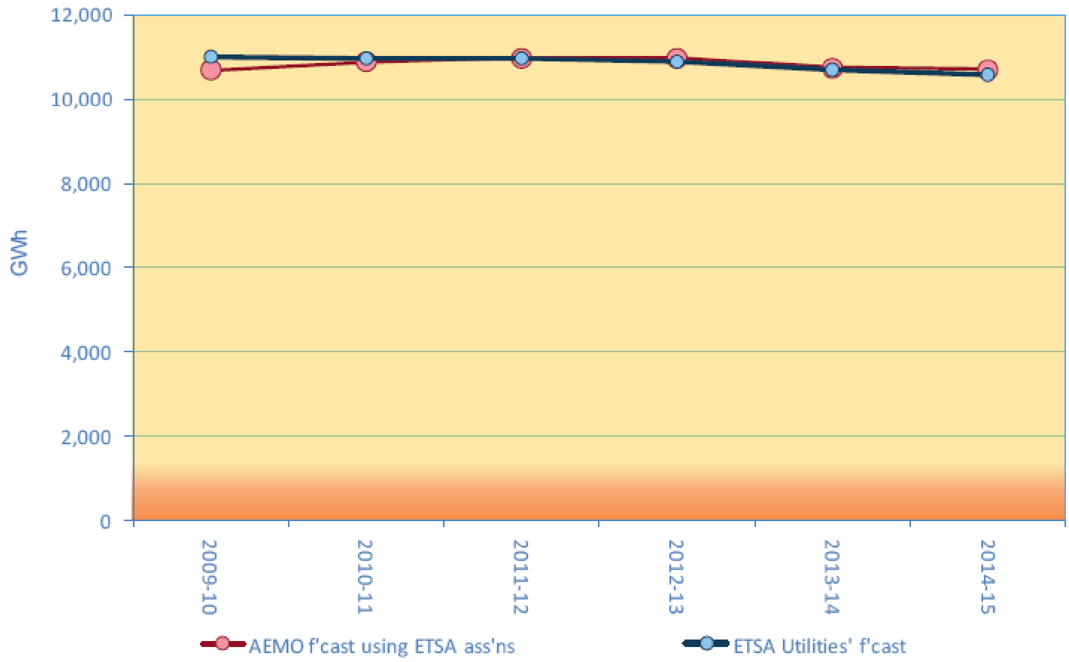
- hot water heating sales forecasts
- post model adjustments applied to the baseline forecasts.

Review of underlying forecasting models

AEMO evaluated ETSA Utilities' underlying energy sales forecast model by comparing ETSA Utilities' total sales forecasts with forecasts prepared using its own model and the same economic and energy efficiency assumptions used by ETSA Utilities.

AEMO found that the forecasts are almost identical over the next regulatory control period, as shown in figure 6.5. AEMO therefore concluded that ETSA Utilities' energy sales forecasting model operates in a broadly similar manner to AEMO's model.[235]

Figure 6.5: Energy sales forecasts



Source: AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 48.

Review of key driver forecasts

AEMO stated that the economic assumptions underpinning its energy sales forecasts were prepared by KPMG Econtech during March 2009.[236] AEMO compared ETSA Utilities' forecasts of key drivers, including economic drivers and projection of future

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235 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 48.

236 The KPMG Econtech forecasts were made available by NEMMCO (now AEMO) to all NEM jurisdiction planning bodies to develop forecasts for the 2009 Electricity Statement of Opportunities. See AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. i.

retail electricity prices to KPMG Econtech's forecasts and made the following observations:[237]

- average growth in dwelling investment between 2009–10 and 2014–15—ETSA Utilities –2.0 per cent, KPMG Econtech –4.5 per cent
- average growth in manufacturing sector gross valued added between 2009–10 and 2014–15—ETSA Utilities –3.0 per cent; KPMG Econtech 2.8 per cent
- average growth in other industry gross valued added (excluding agriculture, mining, manufacturing and the housing sector) between 2009–10 and 2014–15—ETSA Utilities –4.9 per cent; KPMG Econtech 3.2 per cent
- average annual real electricity price increase between 2007–08 and 2014–15—ETSA Utilities 5.2 per cent; KPMG Econtech 2.4 per cent.

Review of water heating energy sales forecasts

Since ETSA Utilities has separately forecast water heating energy sales, as part of its review AEMO prepared its own water heating energy sales forecasts for comparison.

AEMO considered that energy sales forecasts for water heating should be based on a model which reasonably replicates historical sales and customer numbers over the past five years, due to the structural change in water heating energy sales over this period. In particular the forecasts should take into account changes in customers' preferences towards gas and solar-electric water heating units. AEMO considered that ETSA Utilities' water heating energy sales forecasts showed a break with recent trends and effectively assumed an accelerating structural change in this market sector, which is reflected in the following comparative growth rates:[238]

- actual annual growth during the 12 years to 2001–02 averaged around 0.8 per cent
- actual growth during the 6 years to 2008–09 averaged around –2.6 per cent
- AEMO's forecasts show growth averaging –3.5 per cent to 2014–15
- ETSA Utilities' forecasts show growth averaging –10.8 per cent to 2014–15.

Review of post model adjustments

AEMO reviewed each of ETSA Utilities' post model adjustments for energy efficiency savings to the baseline forecasts, shown in table 6.5Table 6.5. AEMO considered that many of the areas in which ETSA Utilities' has allowed for residential energy efficiency savings should be excluded from its post model adjustments, as these effects have already been reflected in the baseline forecasts or because the adjustments would introduce unwanted upward bias into the forecasts.[239]

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[237] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 25–26.
[238] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. xi.
[239] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 31–37.

AEMO considered that the historical sales and demand data includes the impacts of efficiency measures introduced in the past. AEMO therefore assumed the baseline forecasts include the effects of past policies, and hence implicitly assume that further new measures will continue to be introduced with similar frequency and intensity in the future. AEMO also considered that it is inappropriate to make post model reductions to baseline energy sales forecasts to reflect possible improvement in the efficiency of appliances such as televisions, set top boxes and air conditioners unless similar adjustments are also made to reflect the increased penetration.

AEMO considered that adjustments are warranted in relation to the rising penetration of small scale solar photovoltaics (PV) units and the recently introduced policy to tighten Minimum Energy Performance Standards (MEPS) applying to lighting appliances.[240] AEMO's estimates of these impacts are indicated in table 6.5.[241]

Table 6.5: Efficiency measures effecting annual sales forecasts (GWh)

		2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Installation of small scale solar PV units	ETSA	12.1	15.8	19.0	21.6	24.3	26.9
	AEMO	11.3	15.1	18.9	22.7	26.4	30.2
Residential energy efficiency scheme	ETSA	23.5	44.6	66.6	88.6	110.6	132.6
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioner MEPS	ETSA	0.0	6.0	11.9	17.7	23.4	29.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Television MEPS	ETSA	9.0	18.0	27.0	36.0	45.0	54.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Set-top box MEPS	ETSA	1.8	3.6	5.4	7.2	9.0	10.8
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Standby power MEPS	ETSA	14.9	29.7	44.6	59.4	74.3	89.1
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Lighting MEPS	ETSA	62.9	83.9	104.8	125.8	146.8	159.9
	AEMO	28.7	58.2	88.8	120.1	153.9	189.7
Federal insulation program	ETSA	18.6	30.9	37.1	37.1	37.1	37.1
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Total across all policy areas	ETSA	142.8	232.5	316.4	393.4	470.5	539.4
	AEMO	40.0	73.3	107.7	142.8	180.3	219.9

Source: AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 33.

Overall, AEMO concluded that the differences between the two sets of energy sales forecasts from AEMO and ETSA Utilities largely reflect the use of different

240 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 33–34.
241 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 33.

economic assumptions and post-model adjustments for energy efficiency savings, rather than effective underlying model differences.[242]

Issues and AER considerations

Underlying energy sales forecast model

The AER accepts AEMO's finding that ETSA Utilities' underlying energy sales model operates in a broadly similar manner for all practical purposes with AEMO's model. The AER understands that the differences in the energy sales forecasts between the two organisations are largely driven by differences in key economic driver forecasts, retail electricity price projections, water heating energy sales and post model energy efficiency savings adjustment, as discussed below.

Key economic driver forecasts

The AER notes that NIEIR's economic forecasts are materially lower compared to the 2009 South Australian budget report forecasts, and KPMG Econtech's forecasts used by AEMO.

The AER understands that the forecasts contained within the South Australian budget have factored in the potential impacts of the global financial crisis (GFC) and projected 1 per cent and –0.5 per cent growth in 2008–09 and 2009–10 respectively.[243] The AER also notes that according to more recent forecasts produced by Access Economics, ANZ Bank and the South Australia Department of Treasury and Finance, 2008–09 gross state product (GSP) growth is estimated to be higher compared to the budget forecast, at around 1.0 to 1.75 per cent.[244] The AER therefore considers that NIEIR appears to have over estimated the impacts of the GFC in preparing its state economic growth forecasts.

The South Australian state budget also forecasts a strong recovery from the GFC with growth in GSP of 2.25 per cent in 2010–11 and 4.25 per cent for the two years 2011–2012 and 2012–13.[245] In contrast, NIEIR's forecasts show much slower recovery in GSP growth over the same period, of 1.4 per cent, 2.4 per cent and 1.1 per cent.[246] The AER therefore considers that NIEIR appears to have under estimated the economic recovery following the peak of the GFC.

The AER then assessed projected GSP for the period 2008–09 to 2014–15 using three sets of forecasts, from NIEIR, KPMG Econtech and the South Australian government. The AER found that NIEIR's forecast of cumulative GSP growth over the period 2008–09 to 2012–13 is around 7.4 per cent lower than the South Australian government forecasts. NIEIR's forecast of cumulative GSP growth over the period 2008–09 to 2014–15 is around 12.9 per cent lower compared to KPMG Econtech's

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242 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, pp. 48–49.

243 South Australian State Government, *2009–10 Budget overview*, p. 16.

244 South Australia Department of Trade and Economic Development, *South Australia's Economic Performance Update*, May 2009, p. 2.

245 South Australian State Government, *2009–10 Budget overview*, p. 16.

246 ETSA Utilities, *Regulatory proposal*, July 2009, attachment D.1: NIEIR energy sales forecast, p. 21.

forecasts.[247] The AER therefore considers that NIEIR appears to have under estimated the cumulative GSP growth over the next regulatory control period.

The AER also compared NIEIR's South Australian employment growth rates against the South Australian state budget forecasts, as presented in table 6.6.[248] The AER found that the cumulative employment growth forecast by NIEIR is around 5.4 per cent lower compared to South Australian government forecasts for the period 2008–09 to 2012–13. The AER therefore considers that NIEIR appears to have under estimated employment growth following the GFC.

The AER considers that ETSA Utilities' assumptions in relation to key economic drivers tend to produce low energy sales forecasts and are not reasonable.

Table 6.6: Comparison of NIEIR, KPMG Econtech and State budget GSP and employment growth forecasts (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
NIEIR employment growth forecasts	2.70	–2.10	–1.40	–0.30	0.00	0.70	0.90
State budget employment growth forecasts	0.75	–1.50	0.50	2.25	2.25		
NIEIR GSP growth rate forecasts	0.10	–0.80	1.40	2.40	1.10	0.50	2.40
KPMG Econtech GSP growth rate forecasts	2.63	1.24	3.94	2.84	2.46	2.81	2.71
State budget GSP growth rate forecasts	1.00	–0.50	2.25	4.25	4.25		

Source: ETSA Utilities, *Regulatory Proposal*, July 2009, attachment D1, NIEIR energy sales forecasts, p. 21; AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. iv; and South Australian Government, *2009–10 Budget overview*, p. 16.

Retail electricity price forecasts

The AER notes SA Water's view that the impact of the CPRS on energy sales forecasts should not be included at this time. The AER considers that it is not unreasonable for a prudent and efficient business to factor into its planning a possible future event which may have a material impact on its business. The AER therefore considers that it is reasonable to include the impacts of the CPRS into the energy sales forecast for ETSA Utilities' network.

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[247] Calculated based on cumulative GSP growth from: ETSA Utilities, *Regulatory proposal*, July 2009, attachment D1, NIEIR energy sales forecasts, p. 2; and AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 27.

[248] ETSA Utilities, *Regulatory proposal*, July 2009, attachment D1, NIEIR energy sales forecasts, p. 21; AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. iv; and South Australian State Government, *2009–10 Budget overview*, p. 16.

AEMO has estimated that around a quarter of the 42.9 per cent increase in retail electricity prices forecast by ETSA Utilities to occur in the next regulatory control period will be due to impacts from the CPRS and other general economic factors. AEMO stated the rest of the increase would be due mainly to general tariff increases.[249] The AER understands that both NIEIR and AEMO have assumed the Treasury CPRS-5[250] scenario applied out to 2015 in preparing their base case electricity retail price forecasts. This scenario has the introduction of the CPRS delayed until 2011 and a capped carbon price of $10 per tonne in 2011–12.[251] The AER considers this assumption to be reasonable at this time.

The AER notes that a material portion of the retail electricity price growth forecast by NIEIR is due to an update of initial energy sales forecasts by ETSA Utilities in May 2009. ETSA Utilities stated that the update to the energy sales forecast was to account for the ‘implied movement in prices by its submission’.[252] NIEIR also provided the following short summary on the update in its report:[253]

> In preparing ETSA’s regulatory proposal, ETSA calculated the implied distribution and transmission prices. These implied prices .... were then added to the pre-existing price outlooks for residential and business customers, and the model re-run to produce the sales forecasts for ETSA.

The AER notes that NIEIR’s updated retail electricity price forecasts result in an approximate 200 GWh reduction in ETSA Utilities’ forecast annual energy sales, compared to the original forecasts, over the next regulatory control period.

AEMO has raised concerns on this issue, stating that:[254]

> AEMO would also point out that there is a degree of circularity in ETSA Utilities’ approach to its price forecasts, with higher prices driving sales lower, requiring that a higher price be set by the AER and so forth.

As outlined in the previous section, the AER notes that ETSA Utilities’ forecasts of key drivers are not reasonable and tend to produce low energy sales forecasts. The AER considers that NIEIR’s original energy sales forecasts, based upon its forecasts of key drivers, are inappropriate inputs into the PTRM to derive ETSA Utilities’ distribution tariffs. As a result, it is not reasonable to subsequently use these tariffs as the basis for updating the initial energy sales forecasts. The AER therefore considers that ETSA Utilities’ proposed adjustments to NIEIR’s initial retail electricity price and energy sales forecasts are not reasonable.

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249 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 28.

250 Treasury CPRS–5 assumes a slower start to global emission reductions, and Australia’s medium-term target is 5 per cent below 2000 levels by 2020. Accessed from: <http://www.treasury.gov.au/lowpollutionfuture/report/html/00_Executive_Summary.asp>.

251 ETSA Utilities, *Regulatory proposal*, July 2009, attachment D1, NIEIR energy sales forecasts, p. 28.

252 ETSA Utilities, *Regulatory proposal*, July 2009, attachment D1, NIEIR energy sales forecasts, pp. 57–58.

253 ETSA Utilities, *Regulatory proposal*, July 2009, attachment D1,NIEIR energy sales forecasts, pp. 57–58.

254 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. iv.

Post model adjustment for energy efficiency savings

The AER has considered AEMO's review of ETSA Utilities' post model adjustment for energy efficiency savings and supports AEMO's conclusion that the majority of the post model adjustments are not reasonable, as the impacts are already reflected in the baseline forecasts.

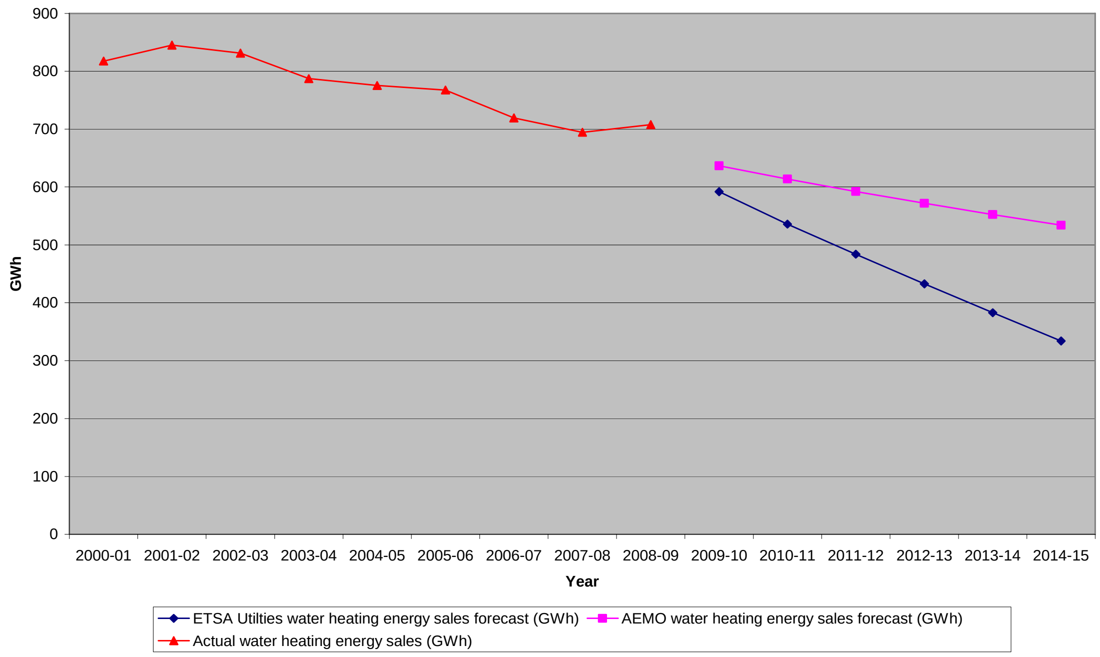
The AER agrees with AEMO's conclusion that adjustments are warranted in relation to the rising penetration of small scale solar PV units, and the recently introduced policy to tighten MEPS applying to lighting appliances, as these policy effects have the potential to significantly change the existing profile of demand. Therefore the AER accepts ETSA Utilities' post model energy efficiency saving adjustments in relation to these two areas.

The AER recognises that the efficiency standard for appliances such as LCD TVs and digital set–top boxes may reduce ETSA Utilities' energy sales through energy efficiency savings. However, it is inappropriate to only apply post model adjustments for possible energy efficiency savings, in the absence of similar adjustment to reflect their increased penetration. Therefore the AER considers ETSA Utilities' post model adjustments for possible efficiency improvement are not reasonable, and are likely to introduce upward bias to the forecasts.

Hot water heating sales forecasts

The AER notes AEMO's view that there have been significant structural changes in this sector during the current regulatory control period, and agrees that AEMO's forecasts reasonably reflect a continuation of current trend of decline in hot water heating energy sales. The AER compared historical trend growth over the period 2003–04 to 2008–09 which averaged around –2.6 per cent, against ETSA Utilities' and AEMO's forecasts of –10.8 per cent and –3.5 per cent growth respectively over the next regulatory control period. The AER found that ETSA Utilities' energy sales forecast shows a clear deviation from the current trend. The AER concluded that AEMO's forecast of –3.5 per cent growth over the next regulatory period as shown in figure 6.6 represents a more realistic view of hot water heating sales.

Figure 6.6: Comparison between actual water heating sales, ETSA Utilities' and AEMO's water heating sales forecasts



Source: ETSA Utilities, *Regulatory Proposal*, July 2009, RIN pro forma 2.3.8, confidential; and AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. 54.

AER conclusion

The AER considers that ETSA Utilities' energy sales forecasts are not reasonable. In particular, the AER considers that ETSA Utilities' forecasts of key economic drivers, water heating sales, and the majority of its post model adjustments for energy efficiency savings are inappropriate.

The AER notes the submissions from Business SA, COTA, SACOSS and ECCSA on the reasonableness of ETSA Utilities' energy consumption growth forecasts. The AER and AEMO have undertaken a detailed analysis of ETSA Utilities' energy sales forecasts and have identified a number of issues, particularly in relation to the forecast of key economic drivers, hot water heating energy sales, and the treatment of energy efficiency savings. Based on its consideration of AEMO's report and the AER's own analysis of ETSA Utilities' regulatory proposal, the AER considers that the energy sales forecasts 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. In addressing the issues outlined in section 6.6.2 regarding key economic drivers, hot water heating sales, and post model adjustment to reflect energy efficiency savings, the AER's conclusion on ETSA Utilities' energy sales forecasts over the next regulatory control period are set out in table 6.7.

Table 6.7: AER conclusion on ETSA Utilities' energy sales forecasts (GWh)

	2010-11	2011-12	2012-13	2013-14	2014-15
Energy sales (GWh)	11 868	12 062	12 399	12 638	12 969

6.6.3 Customer number forecasts

ETSA Utilities regulatory proposal

ETSA Utilities' forecasts of peak demand at 10 per cent PoE, energy sales and customer numbers are provided in table 6.1.

The data in table 6.8 shows that ETSA Utilities' customer numbers have grown by an average annual rate of 0.7 per cent over the period 2005–06 to 2007–08, which is lower than the 2005 forecast approved by ESCOSA of 1.1 per cent.

Table 6.8: ETSA Utilities' actual customer numbers 2005-06 to 2007–08

	2005–06	2006–07	2007–08
Customer numbers – 2005 ESCOSA approved forecast	785 833	796 160	806 817
Customer numbers – actual	776 305	786 703	796 213
Variation	–1.21%	–1.19%	–1.31%

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.3.8, confidential.

Consultant review

The AER engaged MMA to review ETSA Utilities' customer numbers forecasts and forecast methodology.

MMA reviewed the underlying growth drivers of ETSA Utilities' residential customer numbers forecasts in the next regulatory control period. The drivers included growth in the state population and GSP, dwelling starts and persons per dwelling. MMA compared ETSA Utilities' forecasts of these drivers against historical data and other forecasts from various agencies including the Australian Bureau of Statistics (ABS)**,** ESIPC and the Housing Industry Association.[255]

MMA found that ETSA Utilities' forecast of annual population growth of 0.8 per cent over the period 2009–15 lies at the low end of the reasonable forecast range, but considered that the forecasts are consistent with the growth rate experienced between 2001 and 2006.[256]

[255] MMA, *Review of ETSA Utilities customer number forecasts*, 21 September 2009, p. 5.
[256] MMA, *Review of ETSA Utilities customer number forecasts*, 21 September 2009, p. 9.

MMA considered that ETSA Utilities' forecast of a decline in the ratio of persons per household of –0.4 per cent a year is consistent with the historical rate of reduction in persons per household from the ABS census data and appears reasonable.[257]

MMA compared ETSA Utilities' forecasts of residential customer numbers growth to MMA's reasonable range of dwelling growth forecasts for the next regulatory control period. It found that ETSA Utilities' forecasts fall within this range and therefore appear to be reasonable.[258]

MMA reviewed ETSA Utilities' non–residential customer number forecasts using a regression analysis based on the historical relationship between numbers of residential and non–residential customers. Based on the regression result, MMA considered that while ETSA Utilities' forecasts appear to be a little high in the final two years of the next regulatory control period, overall they appear to be reasonable.[259]

Issues and AER considerations

The AER notes MMA's findings that ETSA Utilities' forecasts of annual state population growth of approximately 0.8 per cent over the next regulatory period is lower than the ABS projection of 0.97 per cent growth, but is consistent with growth rate experience between 2001 and 2006.

The AER considers that ETSA Utilities' forecast of annual residential customer numbers growth of approximately 1.2 per cent over the next regulatory control period is reasonable, as it lies within MMA's expected range of 1 to 1.5 per cent established based on its analysis of dwelling growth and changes in persons per dwelling.

The AER considers that MMA's regression analysis of ETSA Utilities' non–residential customer number forecasts, which is based on the historical relationship between residential and non–residential customer numbers, is appropriate. Based on the result of MMA's regression analysis, the AER considers that ETSA Utilities' forecast non–residential customer numbers growth is reasonable.

AER conclusion

Based on MMA's assessment, and the results of the AER's review of ETSA Utilities' regulatory proposal, the AER considers that the customer number forecasts contained within ETSA Utilities' regulatory proposal 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 also considers ETSA Utilities' customer number forecasts are appropriate inputs into the AER's PTRM.

6.7 AER conclusion

The AER considers the global and spatial peak demand forecasts proposed by ETSA Utilities provide a realistic expectation of the demand forecast required to achieve the

257 MMA, *Review of ETSA Utilities customer number forecasts*, 21 September 2009, p. 10.
258 MMA, *Review of ETSA Utilities customer number forecasts*, 21 September 2009, pp. 12–14.
259 MMA, *Review of ETSA Utilities customer number forecasts*, 21 September 2009, p. 15.

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 the energy sales forecasts proposed by ETSA Utilities 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 the customer numbers forecasts proposed by ETSA Utilities 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 conclusion on ETSA Utilities' global peak demand, energy sales and customer number forecasts over the next regulatory control period are set out in table 6.9.

Table 6.9: AER conclusion on ETSA Utilities' peak demand, energy sales and customer number forecasts

	2010-11	2011-12	2012-13	2013-14	2014-15
Peak demand – including major customers (MW)	3129	3227	3358	3434	3522
Energy sales (GWh)	11 868	12 062	12 399	12 638	12 969
Total customer numbers	828 162	838 160	846 778	854 779	863 230

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 are the energy sales forecasts specified in table 6.9 of this draft decision.

7 Forecast capital expenditure

7.1 Introduction

This chapter sets out the AER's conclusions on forecast capex allowances for ETSA Utilities for the next regulatory control period. It also:

- discusses the framework the AER has applied in assessing the proposal
- discusses the outcomes of the current regulatory control period
- provides a general overview of the proposal
- lists comments made by stakeholders on the proposal
- sets out the AER's considerations and responses to stakeholder comments.

The AER's conclusions and the estimates of forecast capex allowances for ETSA Utilities during the next regulatory control period are set out in section 7.9 of this chapter.

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 ETSA Utilities 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 capex forecast included in ETSA Utilities’ regulatory proposal 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 are robust and reflect a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives

- 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 proposal 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 mirrors the requirements in chapter 6 of the NER. However, the application of this approach to ETSA Utilities 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 detailed review of each and every possible project. Specifically:

- while a range of ETSA Utilities' projects and programs were reviewed by the AER and its consultants, the AER's overall assessment has placed less reliance on individual project and program reviews, in contrast to its approach for TNSPs

- due to the limitations of reviewing a large number of projects and programs in detail, relatively more reliance has been placed on a review of ETSA Utilities' policies and procedures and the underlying assumptions such as demand forecasts and cost estimates, to gauge the reasonableness of the proposed capex allowances

- with assistance from its consultant, the AER has considered more general factors (for example trends in asset age, faults) and methods (for example expenditure modelling) in examining investment proposed at lower voltages in the network

- where appropriate, the AER and its consultants have examined departures from identified trends in historical expenditure more closely.

7.4 Current period outcomes

This section summarises the expenditure outcomes of ETSA Utilities compared to the allowances set by ESCOSA. The purpose of the review is to identify any cost drivers that were not identified for the current regulatory control period that should be recognised when examining the proposals for the next regulatory control period.

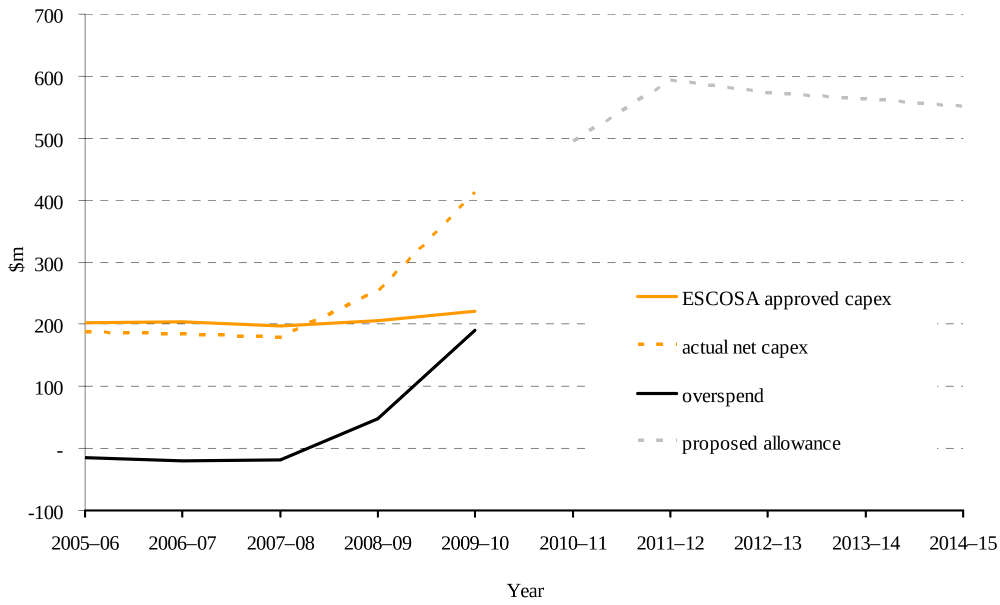
ETSA Utilities is expected to overspend its regulated capex allowance by approximately $185 million ($2009–10) or 19 per cent of the allowance set by ESCOSA.[260] This is shown in table 7.1 and figure 7.1.

Table 7.1: Capex outcomes ($m, 2009–10)

	2005–06	2006–07	2007–08	2008–09 (estimate)	2009–10 (estimate)	Total
Regulatory allowance	201.6	203.8	197.3	206.3	221.7	1030.7
Actual gross capex	186.9	183.3	179.4	254.0	412.8	1216.4
Overspend	–14.7	–20.5	–17.9	47.7	191.1	185.7

Source: AER analysis of historical capex; ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using Australian Bureau of Statistics (ABS) inflation data.
Note: Includes customer contributions.

Figure 7.1: ETSA Utilities actual and proposed capex ($m, 2009–10)



Source: AER analysis of historical capex; ETSA Utilities: RIN pro forma 2.2.1, converted to real terms using ABS inflation data.
Note: Includes customer contributions.

ETSA Utilities stated the underspend in the first three years and overspend in the last two years of the current regulatory control period are due to:[261]

- higher contributions being received than had been anticipated during the determination process, ESTA Utilities stated that:[262]

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260 ETSA Utilities, *Regulatory proposal*, July 2009, p. 98.
261 ETSA Utilities, *Regulatory proposal*, July 2009, p. 98.

> The contributions regime for 2005–2010 represented a significant change from the prior period, resulting from extensive consultation undertaken by ESCOSA. Although ESCOSA and ETSA Utilities undertook best endeavours to estimate the implications of the new regime, a number of factors, including the actual mix of projects undertaken by ETSA Utilities in the current period has resulted in contributions significantly exceeding forecast levels.

- deferred capex where this has been efficient and prudent
- a significant ramp up in expenditure towards the end of the current regulatory control period due to aged asset replacement and peak demand growth.

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:

- actual customer contributions in the current regulatory control period exceeded forecast levels by about $223 million ($2009–10) or 148 per cent. On a net expenditure basis, ETSA Utilities will have underspent its allowances by approximately $37 million ($2009–10) or 4 per cent of the allowances set by ESCOSA[263]
- the large overspend in the last year of the current regulatory control period was partly the result of a $103 million one off forecast increase in new customer connection expenditure, which is not expected to continue in the next regulatory control period and partly as a result of a ramp up of its asset replacement program
- a large proportion of the historical underspend was related to the 'reinforcements and upgrade' (capacity) category. ETSA Utilities has forecast an increase in this expenditure category over the next regulatory control period.

In conclusion, the AER considers that the major reasons for the observed underspend and overspend are known to ETSA Utilities and is satisfied these reasons have been taken into account when developing its current regulatory proposal. This improves the likelihood that ETSA Utilities has presented a complete case on which the AER is able to assess the proposal against the capex criteria. However, the AER notes that customer contributions are still problematic in determining appropriate forecasts for capex relating to network augmentation.

7.5 ETSA Utilities regulatory proposal

ETSA Utilities proposed a capex allowance of $2773 million ($2009–10) for the next regulatory control period. Table 7.2 sets out ETSA Utilities' proposed capex by expenditure purpose.

262 ETSA Utilities, *Regulatory proposal*, July 2009, p. 98.
263 ETSA Utilities, *Regulatory proposal*, July 2009, p. 97.

Table 7.2: ETSA Utilities capex by expenditure purpose ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Demand driven						
Capacity	146.6	194.4	147.6	144.6	142.6	775.8
Customer connection	130.6	139.1	127.6	141.0	143.0	681.3
Quality, reliability and security of supply						
Asset replacement	79.7	91.4	96.8	98.9	99.9	466.7
Security of supply	15.5	45.9	65.3	33.8	9.9	170.4
Reliability	4.9	5.0	5.0	5.1	5.2	25.2
Safety and environment	29.4	36.4	40.0	42.0	42.7	190.5
Non–network expenditure	67.8	59.0	70.3	78.0	88.7	363.8
Other-superannuation and equity raising costs	19.3	21.6	20.1	19.5	18.3	98.8
Total (including customer contributions)	493.8	592.8	572.7	562.9	550.3	2772.5
Customer contributions	–87.4	–93.8	–85.0	–95.0	–96.0	–457.2
Total (net of customer contributions)	406.4	499.0	487.7	467.9	454.3	2315.3

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 108.
Note: Totals may not add due to rounding.

ETSA Utilities' proposed capex program for the next regulatory control period represents a 128 per cent increase from the current regulatory control period.[264] ETSA Utilities stated that significantly increased expenditure is required in order to meet the capex objectives in the NER in the next regulatory control period.[265] The key drivers of ETSA Utilities' forecast capex program were identified as:[266]

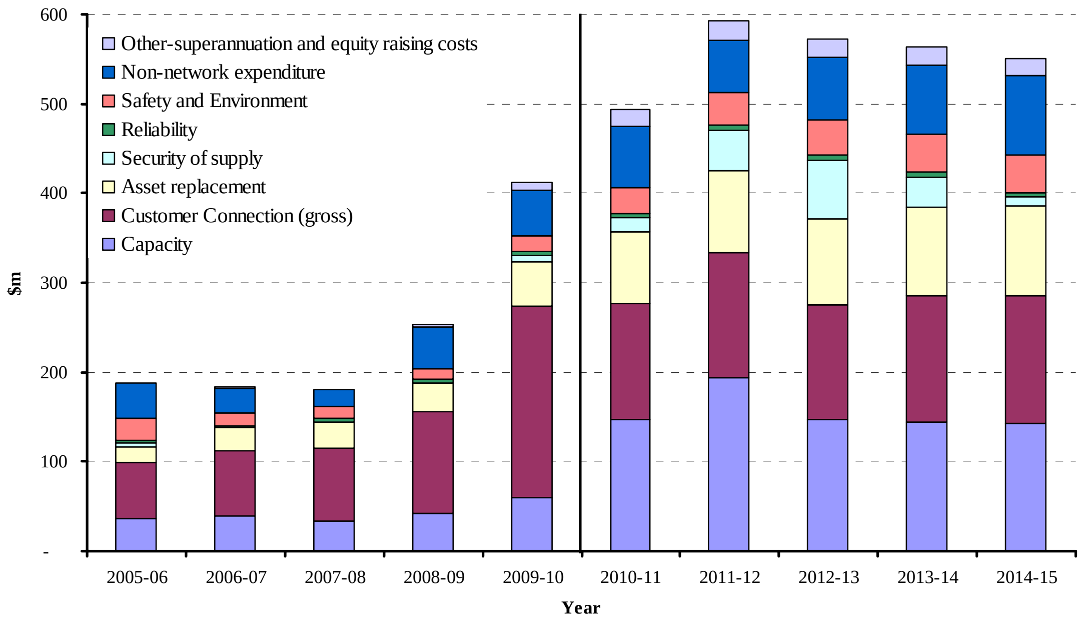
- *Electricity Transmission Code* changes
- change in low voltage network planning criteria
- continued peak demand growth
- increase in major customer projects to support South Australian infrastructure growth
- ramp-up in replacement programs to begin mitigating aged asset risks

[264] Includes customer contributions.
[265] ETSA Utilities, *Regulatory proposal*, July 2009, p. 108.
[266] ETSA Utilities, *Regulatory proposal*, July 2009, p. 109.

- upgrade to the Kangaroo Island network to improve security and support economic growth on the island
- continuing programs to address network security and environmental risks
- growth in the organisation's size.

Figure 7.2 compares ETSA Utilities' actual and proposed capex by driver.

Figure 7.2: ETSA Utilities actual and proposed capex by driver ($m, 2009–10)



Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

ETSA Utilities proposed $1457 million demand driven ($2009–10) network capex.[267] This represents an increase of 93 per cent (in real terms) from the current regulatory control period and will comprise around 53 percent of the total forecast capex program. ETSA Utilities attributed this increase predominantly to capacity related expenditure in response to spatial peak demand growth. ETSA Utilities stated that capacity related expenditure makes up a significant component of its capital program, and is the major driver of capex increases from the current period. ETSA Utilities identified the following key drivers of its forecast increase in capacity expenditure:[268]

- revised low voltage planning criteria, which contributes approximately 22 per cent to the capacity expenditure increase
- electricity transmission code changes, which contribute approximately 22 per cent to the capacity expenditure increase

267 Total includes customer contribution.

268 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 110–118.

- continued peak demand growth
- network utilisation approaching maximum prudent limits.

For the next regulatory control period, ETSA Utilities proposed $662 million network expenditure associated with maintaining the quality, reliability and security of supply. This is approximately 260 per cent (in real terms) higher than expenditure levels in the current regulatory control period, and comprises about 24 per cent of the total forecast capex program. ETSA Utilities identified the following expenditure categories as the key drivers for the forecast increase in quality, reliability and security of supply capex:[269]

- security of supply capex ($170 million)—Kangaroo Island network security upgrades, replacement of ETSA Utilities' system control and data acquisition (SCADA) system and acquisition of land for future substations
- asset replacement capex ($466 million)—ramp up in expenditure to begin mitigating aged asset risks.

ETSA Utilities proposed safety and environment capex for the next regulatory control period that is 138 per cent (in real terms) higher than that of the current regulatory control period. It attributed this expenditure to the continuing programs to address safety and environmental risks.[270]

ETSA Utilities forecast $364 million for non–network capex for the next regulatory control period. This represents a 98 per cent increase from the current regulatory control period. The main driver for the non–network capex increase is to support growth in the organisation's size and capabilities to deliver programs required in the next regulatory control period.[271]

ETSA Utilities proposed $99 million of other capex expenditure, which is an increase of 734 per cent (in real terms) on the current regulatory control period. It attributed this expenditure to the capital component of additional payments required for superannuation funds resulting from market conditions and equity raising costs.[272] ETSA Utilities noted that equity raising costs have been included in its capex forecast rather than its opex forecast because the nature of equity raising is such that it exists in perpetuity until the assets being funded are realised.[273]

ETSA Utilities developed its capex plan by aggregating a large number of generally zero based asset management and/or expenditure plans across a range of expenditure categories. ETSA Utilities stated the scope of each expenditure plan, and in many cases the corresponding asset management plan, was determined using a risk based approach that aligns with its capital governance procedures.[274]

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269 ETSA Utilities, *Regulatory proposal*, July 2009, p. 109.
270 ETSA Utilities, *Regulatory proposal*, July 2009, p. 109.
271 ETSA Utilities, *Regulatory proposal*, July 2009, p. 109.
272 ETSA Utilities, *Regulatory proposal*, July 2009, p. 109.
273 ETSA Utilities, *Regulatory proposal*, July 2009, p. 139.
274 ETSA Utilities, *Regulatory proposal*, July 2009, p. 99.

ETSA Utilities utilised independent consultants for the development or assessment of the identified scope in order to provide confirmation of scope prudence. Once the scope had been determined, this was then costed, generally on the basis of historical unit or 'building block' costs.[275]

In developing its forecasts, ETSA Utilities considered the substitution possibilities between opex and capex and applied escalation for forecast changes in the real costs of materials, labour, and contract services anticipated over the next regulatory control period.[276]

7.6 Submissions

The AER received submissions from Business SA, Council on the Ageing Seniors Voice (COTA), the Energy Consumers Coalition of South Australia (ECCSA), the Energy Users Association of Australia (EUAA), Origin Energy Retail Pty Ltd (Origin), the South Australian Council of Social Service (SACOSS), SA Water, UnitingCare Wesley (UCW) and the South Australian Minister for Energy, the Hon Patrick Conlon MP (SA Energy Minister).

The submissions raised concerns regarding the following aspects of ETSA Utilities' regulatory proposal:

- **Efficiency and prudence of capex—**submissions suggested that the need for the significant capex program should be scrutinised carefully, including the necessity and cost of individual capital investments and the risks of deferral against the risks of unnecessarily early investment.[277] The EUAA was critical of the AER's approach to benchmarking to date and stated that the AER must properly benchmark the proposed expenditure against that of an efficient DNSP as required under the NER.[278]

- **Deferral or prioritisation of capex—**the ECCSA recommended that the AER review ETSA Utilities detailed risk analysis for each capex project, including an assessment for delays in implementation, to assess whether the project is necessary during the next regulatory control period or could be deferred with little risk.[279] UCW suggested that ETSA Utilities' seven largest proposed capex projects and programs be prioritised from the perspective of low income households, and that a more reasonable capex budget for these projects in the next regulatory control period would be $235 million rather than $627 million.[280]

- **Unit costs—**Business SA submitted that a declining scale should be applied to historical unit costs used in justifying cost estimates, to reflect efficiencies that

[275] ETSA Utilities, *Regulatory proposal*, July 2009, p. 99.
[276] ETSA Utilities, *Regulatory proposal*, July 2009, p. 99.
[277] Business SA, *Submission to the AER on ETSA Utilities' regulatory proposal 2010–15*, August 2009, p. 6; EUAA, *Submission to the AER on ETSA Utilities regulatory proposal for the period 2010–15*, 28 August 2009, p. 11; and ECCSA, *ETSA Utilities application, a response*, August 2009, p. 13.
[278] EUAA, *Submission to the AER*, August 2009, pp. 8–9.
[279] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 26.
[280] UCW, *Distribution price review for South Australia, 2010–2015, conducted by the Australian Energy Regulator, August 2009*, pp. 15–16.

most companies achieve over time through learning by doing and technology improvements.[281]

- **Cost escalation**—the ECCSA stated that the AER approach of allowing real cost escalation above inflation relieves DNSPs of cost pressures faced by other firms, and that the AER should return to CPI escalation to cover the costs of materials for the next regulatory control period.[282] Business SA submitted that ETSA Utilities' forecast real wage increase of 3.3 per cent per annum appears higher than can be justified.[283] SA Water stated that it is not prudent to forecast material increases in labour and materials costs in a recovering economic climate.[284]

- **Augmentation capex**—

  - interested parties questioned the relationship between forecast demand and customer number growth rates which are lower than, or consistent with, historical rates and the proposed significant increases in capacity and customer connection related capex.[285] Business SA stated that priority should be given to the connection of new major projects and development initiatives.[286] The SA Energy Minister supported the proposed City West works related to changes to the *Electricity Transmission Code*.[287]

  - Origin queried the basis for ETSA Utilities' projection of an increase in network utilisation, given a slight reduction in peak demand growth and a large increase in investment in augmentation.[288] The EUAA stated that evidence from the 2009 heat wave suggests the ETSA Utilities network held up very well despite enormous increases in peak demand, and that the level of spare capacity and ETSA Utilities' competence in managing its network should not be underestimated.[289]

- **Replacement capex**—

  - Business SA submitted that it supports ETSA Utilities use of condition based monitoring as a basis for asset replacement, though an almost tripling of expenditure in this area requires analysis to confirm it is all required. Business SA and the SA Energy Minister also supported the proposed CBD aged asset replacement program.[290]

  - Origin submitted that it would be useful to understand in more detail at which point ETSA Utilities sees the trend of under investment in the network,

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281 Business SA, *Submission to the AER*, August 2009, p. 6.
282 ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 20–24.
283 Business SA, *Submission to the AER*, August 2009, p. 9.
284 SA Water, *Submission on ETSA Utilities regulatory proposal*, August 2009, p. 3.
285 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 19; and EUAA, *Submission to the AER*, August 2009, p. 11.
286 Business SA, *Submission to the AER*, August 2009, p. 6.
287 SA Energy Minister, *Submission to the AER*, September 2009, p. 2.
288 Origin, *ETSA Utilities*, August 2009, p. 6.
289 EUAA, *Submission to the AER*, August 2009, p. 5.
290 Business SA, *Submission to the AER*, August 2009, p. 6; and SA Energy Minister, *Submission to the* AER, September 2009, p. 2.

brought about by an ageing asset base, will have peaked. Origin also noted ETSA Utilities' reliance on age as a proxy for condition as cause for concern, and queried whether ETSA Utilities' condition based monitoring strategies will be fully implemented by the start of the next regulatory control period.[291]

  - the ECCSA stated that there appeared to be considerable scope for deferral of asset replacement capex through targeted maintenance programs, and suggested the AER develop a set of principles to guide its assessments of asset renewal that could be deferred.[292] The ECCSA also sought advice from the AER as to how to ensure that assets are not replaced before the end of their useful lives, and that asset replacement needs are identified from a commercial (rather than physical) point of view.[293]

- **Security of supply capex—**the SA Energy Minister supported the proposed Kangaroo Island network security project as maintaining security and reliability of supply and supporting further development in this region. The SA Energy Minister suggested that the extensive use of high cost diesel generators on Kangaroo Island indicated the pressing need for further network development.[294]

- **Reliability capex—**COTA submitted that there is evidence that South Australian electricity customers are predominantly happy with current reliability levels and are unwilling to pay for greater reliability of supply.[295] The ECCSA suggested there is scope for capex deferral in the area of reliability, and questioned the need to comply with reliability obligations where the level of expense required to do so is not warranted.[296] Business SA suggested that lowest priority in the capex program should be given to investments where supply is already reliable and secure.[297]

- **Underutilisation of demand management—**

  - Business SA urged the AER to analyse the scope for reducing network capex by swapping increased demand management projects in their place.[298]

  - SACOSS, supported by COTA, submitted that ETSA Utilities' proposal fails to meet the demand management needs of the network, and instead proposes a capex program focussing on expensive, under utilised infrastructure that will fail to meet the long term interests of consumers.[299]

  - UCW expressed disappointment at the apparent retreat from demand management strategies evident in ETSA Utilities' proposal, and suggested it

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291 Origin, *ETSA* Utilities, August 2009, p. 7.
292 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 15.
293 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 25.
294 SA Energy Minister, *Submission to the* AER, September 2009, p. 1.
295 COTA, *ETSA distribution price review 2010–2015*, 27 August 2009, p. 3.
296 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 15.
297 Business SA, *Submission to the AER*, August 2009, p. 6.
298 Business SA, *Submission to the AER*, August 2009, p. 7.
299 SACOSS, *Submission to the AER*, August 2009, pp. 3–4; and COTA, *ETSA distribution price review*, August 2009, p. 5.

would be appropriate for the AER to set demand management targets to be achieved by ETSA Utilities in the next regulatory control period.[300]

- the EUAA commented that the AER's approach to demand management does not provide distributors with sufficient incentives to pursue demand management and does not sufficiently prioritise demand management issues.[301]

- **Other capex—Equity raising costs—**

  - the EUAA submitted that the AER should examine ETSA Utilities' claim for equity raising costs in the context of the actual cost of such equity raising considering its ownership structure as a partnership between HEI Utilities, CKI Utilities, and Spark Infrastructure.[302]

  - the ECCSA stated that a significant amount of the capex is for equity raising costs. If the amount of increased equity required is less due to a less aggressive capex program, this reduction will result in a lower equity raising cost.[303]

- **Deliverability—**

  - interested parties questioned ETSA Utilities' capacity to prudently deliver the proposed capex program, considering the significant increase in expenditure proposed and its history of underspending in the first three years of the current regulatory control period.[304]

  - the ECCSA queried whether the proposed capex program can be managed effectively given the expected large volume of investment projects nationally, against a background of limited resources of labour, plant and materials.[305]

  - Business SA suggested that any projects considered unlikely to be delivered in the regulatory control period should be removed from the capex proposal.[306]

7.7 Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of ETSA Utilities' capex proposal.[307]

PB adopted a phased approach to its review of ETSA Utilities' capex proposal. The approach was designed to provide broad coverage of the capex proposal while

300 UCW, *Distribution price review for South Australia*, p. 14.
301 EUAA, *Submission to the AER*, August 2009, p. 11.
302 EUAA, *Submission to the AER*, 28 August 2009, p. 11.
303 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 27.
304 SA Water, *Submission on ETSA Utilities regulatory proposal*, 28 August 2009, p. 1; UCW, *Distribution price review for South Australia*, p. 18; and ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 8–9.
305 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 8.
306 Business SA, *Submission to the AER*, August 2009, p. 6.
307 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015 for Australian energy Regulator, October 2009*, p. xii.

enabling a more detailed examination of key issues as required. The phased approach involved detailed desktop review of the capex proposal, onsite meetings with ETSA Utilities staff to discuss essential elements of the capex proposal, development of preliminary views on key issues, discussion and agreement with the AER to a scope of works for the focussed review stage and further discussions with ETSA Utilities to establish full understanding of specific capex items.[308]

In assessing whether ESTA Utilities' proposed capex is prudent and efficient, PB:[309]

- assessed whether ETSA Utilities is acting efficiently in accordance with good electricity industry practice through a review of capital governance, policy and procedures, cost estimating practices, and specific reviews of certain expenditures
- assessed whether there is a justifiable need for the proposed capital investment within each expenditure category
- after confirming the need for a capital investment, assessed whether all reasonable options have been considered and the most efficient investment selected to satisfy that need
- where a capital investment is based on assumptions about future conditions, assessed whether those assumptions are reasonable.

PB's review of ETSA Utilities' forecast capex allowance excluded benchmarking of unit costs, the level of forecast demand and the deliverability of the proposed works program from its scope of work.[310]

Based on its review, PB found $1716 million (74 per cent) of ETSA Utilities' proposed system capex to be prudent and efficient. PB's key findings are as follows:[311]

- ETSA Utilities' capital governance is consistent with good electricity industry practice
- risk assessment practices do not support project prioritisation as would be expected from a prudent operator
- planning criteria are aligned with good electricity industry practice and the demand forecast is consistently applied
- although options analysis is not formally documented, ETSA Utilities appears to consider a reasonable range of options in capacity planning decisions
- non–network alternatives and demand management opportunities are considered and pursued

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308 PB, *Report – ETSA Utilities*, October 2009, pp. 3–4.
309 PB, *Report – ETSA Utilities*, October 2009, p. 4.
310 PB, *Report – ETSA Utilities*, October 2009, p. 5.
311 PB, *Report – ETSA Utilities*, October 2009, pp. xii–xiv.

- the efficiency of ETSA Utilities' revised asset management approach has not been demonstrated.

PB recommended reductions in ETSA Utilities' proposed system capex totalling $594 million in the following categories, for the reasons outlined:[312]

- a reduction of $102 million to the low voltage network capacity upgrade program as PB is of the view that the risk assessment overstates the risk, and the underlying analysis does not support the full scope of the proposed program

- a reduction of $31 million to the customer connection capex to reflect the removal of a contingency allowance for unidentified projects which in PB's view is unsupported and has not been demonstrated to be prudent and efficient

- a reduction of $228 million to the asset replacement program as in PB's view, ETSA Utilities' assessment of risk and the basis of its age-based replacement proposals could not be demonstrated to be efficient

- a reduction of $14 million to the security and fencing program to reflect removal of proposed high security fencing projects which exceed industry practice and are not supported by the Energy Networks Association (ENA)[313] guidelines and site risk analysis

- a reduction of $4.7 million to the CBD safety related asset replacement program due to ETSA Utilities' use of a lower risk threshold, which has not been demonstrated to be economically justified, and the lack of demonstration that the timing of these projects is efficient. PB's recommendation reflects the expenditure that would be required if the risk threshold accepted in ETSA Utilities' previous annual budget process was applied

- a reduction of $95 million from the Kangaroo Island security of supply project to reflect PB's view that information provided supports deferral of the undersea cable and the sub-transmission upgrade until after the next regulatory control period

- a reduction of $11 million to the network security of supply program to reflect the removal of costs for operational labour and procurement of land that have been double counted, and removal of costs for the information technology (IT) disaster recovery project which in PB's view is inefficient given the relocation of the network operations centre project which is also planned for completion in the next regulatory control period

- a total reduction of $109 million (6 per cent) to the system capex to reflect inefficiencies in the application of the real cost escalators and the errors in the adjustment of the capex forecast to a 2009–10 basis.

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312 PB, *Report – ETSA Utilities*, October 2009, p. xiv.

313 The Energy Networks Association is the national organisation representing gas and electricity businesses throughout Australia.

PB has assessed ETSA Utilities' proposed non–system capex, including capex for information systems, plant and tools, property and fleet categories, and found the proposed non–system capex to be prudent and efficient. A reduction of $25 million (6 per cent) to the non–system capex is recommended to reflect inefficiencies in the application of the real cost escalators and the errors in the adjustment of the capex forecast to a 2009–10 basis.[314]

PB's specific findings on each area of ETSA Utilities' capex proposal are described in section 7.8.4.

7.8 Issues and AER considerations

This section presents the AER's consideration of the following aspects of ETSA Utilities' regulatory proposal:

- its policies, procedures and methods
- its cost estimation processes
- the application of input cost escalators
- proposed expenditure by major category
- the deliverability of the forecast capex program.

7.8.1 Policies, procedures and methods

This section examines whether ETSA Utilities' capex planning practices are appropriate and provide a framework that is likely to result in prudent and efficient investment decisions. The AER considers that assessing these practices in this manner is relevant for determining whether the AER is satisfied that ETSA Utilities' forecast capex reasonably reflects the capex criteria.

ETSA Utilities regulatory proposal

ETSA Utilities' framework for capex planning activities is articulated through the Board approved asset management policy and high level asset management plan. These documents are supported by a capex directive and specific procedures covering the key areas of capital budgeting, evaluation and approval, and monitoring and post implementation review.[315]

The high level asset management plan, known as Manual 15, governs the development and annual review of individual asset class based asset management plans.[316] ETSA Utilities stated that its capex program for the next regulatory control period has been developed by aggregating these asset management and expenditure plans across a range of expenditure categories.[317]

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314 PB, *Report – ETSA Utilities*, October 2009, p. xv.
315 ETSA Utilities, *Regulatory proposal*, July 2009, RIN proforma 2.3.6.
316 ETSA Utilities, *Regulatory proposal*, July 2009, p. 106.
317 ETSA Utilities, *Regulatory proposal*, July 2009, p. 99.

ETSA Utilities has described the key elements of its capex forecasting process for its regulatory proposal as being:[318]

- determination of project/program scope for each expenditure category, with regard to meeting forecast demand, complying with regulatory and service standard obligations, acceptable levels of business risk, and acceptable levels of safety risk to the public and employees
- analysis of options, including consideration of demand management alternatives and substitution possibilities between capex and opex
- preparation of expenditure forecasts, generally on the basis of historical unit costs, escalated for forecast changes in the real costs of materials, labour and contract services
- executive management and Board review and endorsement of proposed capex plans at strategic stages in the capex development process.

The key inputs that underpin ETSA Utilities' capex forecasts are identified as:[319]

- spatial peak demand growth
- regulatory obligations
- jurisdictional service standards
- network planning criteria
- historical unit costs
- forecast cost escalations for labour, materials and services
- the application of ETSA Utilities' capital governance processes.

ETSA Utilities stated that it has a hierarchy of capital and asset management governance, consisting of Board approved policy, executive management directives, asset management plans, and operating procedures.[320]

The Financial Expenditure Review Committee (FERC) is charged with ensuring the development of prudent and efficient annual capex programs. The FERC, consisting of the Chief Executive Officer, Chief Financial Officer and General Manager Regulation, is responsible for reviewing capital project submissions and endorsing the proposed capital investment program in advance of approval by the ETSA Utilities Board.[321]

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318 ETSA Utilities, *Regulatory proposal*, July 2009, p. 99.
319 ETSA Utilities, *Regulatory proposal*, July 2009, p. 100.
320 ETSA Utilities, *Regulatory proposal*, July 2009, p. 106.
321 ETSA Utilities, *Capital expenditure directive*, p. 6, confidential.

ETSA Utilities engaged UMS Group and K Tothill to assess its corporate and capital governance frameworks against the requirements of the NER. ETSA Utilities stated that these reviews concluded that its corporate and capital governance frameworks reflect good industry practice and are consistent with requirements under the NER.[322]

Consultant review

PB reviewed ETSA Utilities' capex planning and governance policies and procedures as critical elements for assessing the prudence and efficiency of the capex proposal for the next regulatory control period. PB stated it was impractical to assess the reasonableness of each capital investment decision in ETSA Utilities' capex proposal. Therefore PB reviewed the framework in which decisions are made to determine whether the relevant policies and procedures align with good electricity industry practice and if the approach taken by ETSA Utilities is likely to result in appropriate expenditure.[323]

PB developed its view on ETSA Utilities' policies and procedures through a desktop review of documentation, discussions with ETSA Utilities' staff and as an integral part of its review of specific projects and programs of work. Reviewing policies and procedures in the context of specific proposed expenditures allowed PB to confirm appropriate application and implementation.[324]

In relation to ETSA Utilities' capex planning and governance policies and procedures, PB concluded that:

- ETSA Utilities has a well developed documentation framework that demonstrates thorough capital governance practices, and is generally consistent with good electricity industry practice[325]
- ETSA Utilities' planning criteria (with the exception of the revised low voltage network planning criteria) are aligned with good electricity industry practice, suitable for the purposes of forecasting its demand driven investment, and are appropriately applied through the planning process[326]
- the proposed low voltage network planning criteria are more conservative than those applied by other Australian DNSPs[327]
- ETSA Utilities consistently applies its medium growth, spatial demand forecast in identifying the efficient timing of capex projects, and in doing so considers feeder transfers and the use of mobile substations in accordance with its planning criteria to determine the timing of projects[328]

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322 ETSA Utilities, *Regulatory proposal*, July 2009, p. 106.
323 PB, *Report – ETSA Utilities*, October 2009, p. 8.
324 PB, *Report – ETSA Utilities*, October 2009, p. 8.
325 PB, *Report – ETSA Utilities*, October 2009, p. 88.
326 PB, *Report – ETSA Utilities*, October 2009, p. 89.
327 PB, *Report – ETSA Utilities*, October 2009, p. 36.
328 PB, *Report – ETSA Utilities*, October 2009, p. 89.

- a reasonable range of options is considered in ETSA Utilities' capacity planning and, while limited formal documentation is prepared before the business case close to the approval for project expenditure, the options analysis for the reviewed network augmentation projects supported the proposed solution[329]

- the coarseness in the application of the risk assessment procedures at a project level does not support the consistent ranking of projects and analysis of alternative options in the medium term, which influences the identification of capital works priorities for the next regulatory control period[330]

- ETSA Utilities' consideration of efficient non–network solutions was found to be consistent with good electricity industry practice, with efficient non–network alternatives and demand management opportunities being considered and pursued to alleviate network constraints. The efficiency of proposed non–network solutions is evaluated against the benefit of deferring network augmentation[331]

- ETSA Utilities' revised asset management approach, in changing from a fix on failure approach with the effective use of risk mitigation measures to a more extensive condition monitoring approach, had not been demonstrated to be efficient.[332]

AER considerations

The AER has reviewed ETSA Utilities' capex planning and governance framework, and sought advice from PB as to the appropriateness of the key plans, policies and procedures underpinning ETSA Utilities' capex proposal. The AER did not receive any submissions that related specifically to ETSA Utilities' capex planning and governance policies and procedures.

The AER notes that PB has addressed issues with the formulation or application of ETSA Utilities' capex planning and governance policies or procedures in its recommendations about the prudent and efficient level of expenditure for each capex component. The AER's conclusions about the appropriateness of ETSA Utilities' capex planning and governance policies and procedures should be read in conjunction with the discussion of the various specific elements of ETSA Utilities' capex proposal at section 7.8.4.

The AER reviewed ETSA Utilities' capex governance framework, including relevant documentation provided by ETSA Utilities with respect to its capital budgeting, evaluation, approval, monitoring and review procedures, and delegation structures. The AER notes PB's view that ETSA Utilities' capital governance framework is consistent with good electricity industry practice.[333] PB's findings align with the views of ETSA Utilities' consultants, UMS Group and K Tothill, in this regard.[334] The AER notes that ETSA Utilities has a hierarchy of policies, directives, plans and

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329 PB, *Report – ETSA Utilities*, October 2009, p. 89.
330 PB, *Report – ETSA Utilities*, October 2009, p. 89.
331 PB, *Report – ETSA Utilities*, October 2009, pp. 89–90.
332 PB, *Report – ETSA Utilities*, October 2009, p. 90.
333 PB, *Report – ETSA Utilities*, October 2009, p. 88.
334 ETSA Utilities, *Regulatory proposal*, July 2009, p. 106.

procedures, which when taken together appear to set out a robust approach to capital investment governance. On the basis of its review, the AER considers ETSA Utilities' capex governance framework demonstrates thorough capital governance processes.

In relation to capex planning, the AER notes the view of ETSA Utilities' consultant, PB Power, which found that ETSA Utilities' documented planning procedures and planning criteria are robust and in line with good industry practice.[335] Further, the AER notes the views of Sinclair Knight Merz (SKM) and Maunsell Australia Pty Ltd (Maunsell) that ETSA Utilities' asset management policy and asset management plans are generally in accordance with good industry practice.[336]

The AER notes PB's view that ETSA Utilities' planning criteria (with the exception of the revised low voltage network planning criteria) are aligned with good electricity industry practice, suitable for the purposes of forecasting its demand driven investment, and are appropriately applied through the planning process.[337]

The AER also notes PB's advice that ETSA Utilities considers a reasonable range of options, including efficient non–network alternatives, in planning the network, and that demand forecasts are consistently applied in identifying the timing of capex projects.[338]

The AER notes PB's conclusion that the risk assessment process ETSA Utilities applied in developing its capex proposal is appropriate for high level project ranking at a corporate level, but that the detailed assessment of risk within a project or program is simplistic and does not ensure efficient expenditure. The AER also notes PB made a number of recommendations relating to ETSA Utilities' application of risk assessments with respect to proposed non–demand driven capex.[339]

The AER has considered ETSA Utilities' capex planning and governance framework, the reports from ETSA Utilities' consultants and advice from PB. On the basis of this information the AER is generally satisfied that the application of ETSA Utilities' policies and procedures for capex planning and governance is likely to lead to prudent and efficient investment decisions. Where this is not the case, the AER has concluded that specific adjustments should be made to the level of capex proposed by ETSA Utilities as discussed in section 7.8.4.

7.8.2 Cost estimation processes

This section examines the methods adopted by ETSA Utilities to estimate costs for identified investment needs in the context of determining whether the AER is satisfied that ETSA Utilities' forecast capex reasonably reflects the capex criteria.

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335 PB Power, *Review of distribution system planning report*, September 2008, p. 3.
336 SKM, *Review of ETSA Utilities' Asset Management Policy*, April 2008, p. 1; and Maunsell, *Asset Management Plan Review*, November 2008, p. 3.
337 PB, *Report – ETSA Utilities*, October 2009, p. 89.
338 PB, *Report – ETSA Utilities*, October 2009, p. 89.
339 PB, *Report – ETSA Utilities*, October 2009, p. 46.

ETSA Utilities regulatory proposal

To forecast the cost of the majority of its capex program, ETSA Utilities applied a bottom–up method whereby the unit costs of specified capex tasks (such as installing aggregate sections of new plant or equipment) were multiplied by the number of these tasks expected to be performed over the next regulatory control period.[340]

Capex units that make the 10 largest contributions to ETSA Utilities' capex on a volume weighted basis are presented in table 7.3.

Table 7.3: Units that make the 10 largest contributions to ETSA Utilities' capex in the next regulatory control period – confidential

	Capex forecast ($m, 2009–10)
Fully installed underground cable, 66kV, 1600mm^2, copper (per km)	
Fully installed 66kV circuit breaker bay	
Underground cable, 11kV, 630mm, aluminium (per km)	
Substation transformer, 25MVA, 66 to 11kV, excluding installation	
Fully installed 33kV circuit breaker bay	
Fully installed 33kV overhead line, 244mm2, aluminium conductor steel reinforced (per km)	
Fully installed 66kV circuit breaker bay with geographical information system switchgear	
11kV substation feeder exit	
11 kV 2000A switchgear panel with 6 panels	
Installation of 25MVA transformer	
Total	

Source: ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.6, confidential. Capex unit descriptions from ETSA Utilities, issue No: ER.EU.2, response to AER query, 19 August 2009.

ETSA Utilities stated that its unit costs, which reflect the historical costs achieved on similar projects, can be considered efficient because:[341]

- it faces a commercial requirement to deliver appropriate financial returns which also drives unit cost efficiency

[340] ETSA Utilities, *Regulatory proposal*, July 2009, p. 105.
[341] ETSA Utilities, *Regulatory proposal*, July 2009, p. 105.

- its unit costs for a significant sample of representative asset replacement and capacity tasks compare favourably to the unit costs estimated by an independent South Australian construction company engaged by ETSA Utilities.

To forecast the cost of the remainder of its capex program, ETSA Utilities has applied a variety of methods, including:[342]

- Historical cost build up – where forecast scope is largely unknown but likely to be consistent with historical expenditure, ETSA Utilities has utilised a similar approach to the build up of opex in that a base or historical cost has been used, plus cost variations if applicable. This approach has been applied to forecasts capex for reliability, plant and tools, and easements

- Zero-based build up – where ETSA Utilities has been unable to categorise and determine its forecast capex on the basis of unit costs (generally because the scope is new or the type of project is infrequent) zero-based estimates have been developed. These estimates, which have been developed using ETSA Utilities' standard estimating practices, contain estimates for materials, labour, and contract services to implement the required scope of works. Zero-based estimates have been utilised for portions of the build up of the proposed capex for IT, property, and Kangaroo Island undersea cable.

Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of ETSA Utilities' capex proposal. 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 necessary.

In reviewing ETSA Utilities' capex proposal, PB reviewed the costing methodology used by ETSA Utilities to develop its demand driven[343] and asset replacement[344] capex forecasts. As part of its review process, PB discussed with ETSA Utilities the cost estimating processes it applied to develop its demand driven and asset replacement capex forecasts. PB also assessed these processes by reviewing relevant costing spreadsheets and by checking for consistency between:[345]

- the unit costs used in developing the demand driven and replacement capex forecasts

- the unit costs used by ETSA Utilities and the unit costs in the report undertaken for ETSA Utilities

- the unit costs used by ETSA Utilities and ETSA Utilities' historical expenditure.

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342 ETSA Utilities, response to AER query, Issue no: AER.EU.2, 19 August 2009.
343 PB, *Report – ETSA Utilities*, October 2009, pp. 27–28.
344 PB, *Report – ETSA Utilities*, October 2009, pp. 46–47.
345 PB, *Report – ETSA Utilities*, October 2009, p. 47.

PB noted that 41 per cent of the demand driven capex proposed by ETSA Utilities was based on project specific cost estimates rather than on the building-block estimation process, but that this was not unusual where there had been more detailed analysis of costs.[346]

In addition, PB found that around 19 per cent of the base replacement capex forecast, relating to unplanned lines replacement, had been determined on the basis of a ‘top–down’ extrapolation of data that overstated the required expenditure. As a result, PB has recommended an adjustment to ETSA Utilities’ proposed replacement capex to rectify this problem, as discussed in section 7.8.4.2.

Based on its review, and subject to the exceptions noted above, PB concluded that the cost-estimating processes applied to derive ETSA Utilities’ demand driven and asset replacement capex forecasts were based on reasonable building block costs, transparently applied and appropriate for forecasting ETSA Utilities’ capacity expenditure.[347]

AER considerations

In considering ETSA Utilities’ unit costs, the AER has reviewed ETSA Utilities’ proposal, advice from PB and ETSA Utilities’ consultant, and submissions.

The AER notes that ETSA Utilities’ approaches to developing and applying unit costs to forecast its capex requirements are similar to the approaches adopted by other DNSPs and TNSPs.[348]

Regarding the development of the unit costs themselves, the AER notes ETSA Utilities’ view that its internally developed unit costs are likely to be efficient given that they reflect the historical costs achieved on similar projects and that ETSA Utilities is subject to commercial incentives to reduce costs.

In order to confirm that the unit costs reflected actual historical costs, the AER reviewed material provided by ETSA Utilities in support of its proposal in which unit costs were used to compile quotations for past projects.[349] The analysis covered 12 projects, including substation upgrades and high voltage line installation, ranging in value from around $0.5 million to $12 million. The comparison demonstrated that project costs calculated using ETSA Utilities’ unit costs align well with actual project costs. For 50 per cent of the projects assessed, the unit cost estimates were less than actual project costs.

The AER reviewed the unit costs prepared by ETSA Utilities’ consultant and considers those costs provide a suitable benchmark against which to compare ETSA Utilities’ unit costs. In particular, the AER notes that ETSA Utilities’ consultant developed its estimates of ETSA Utilities’ unit costs using two methods of estimation and a variety of personnel. One method involved a panel of people and a facilitator to

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346 PB, *Report – ETSA Utilities,* October 2009, pp. 28.
347 PB, *Report – ETSA Utilities*, October 2009, pp. 28 and 47.
348 PB, *Report – ETSA Utilities*, October 2009, p. 27.
349 ETSA Utilities, *Regulatory proposal*, July 2009, attachment CX009 Unit Cost Methodology, p. 16, confidential.

develop unit costs, while the other method involved an individual with expertise in that area of design and construction work performing a detailed cost breakdown of the tasks and input costs to develop unit costs. The same assumptions were used as inputs to both methods. The AER has confirmed that ETSA Utilities' unit rates compare favourably with those developed by ETSA Utilities' consultant and on this basis, concludes that they are efficient.

The AER also notes PB's conclusion that ETSA Utilities' unit costs were reasonable and suitable for forecasting capex.[350]

Regarding the application of unit costs by ETSA Utilities to its capex build up, the AER notes PB's conclusion that the cost-estimating processes applied to derive ETSA Utilities' demand driven and asset replacement capex forecasts were transparently applied and were appropriate for forecasting ETSA Utilities' capex.[351]

The AER notes Business SA's suggestion that historical unit costs should be adjusted downwards to reflect efficiency improvements over time. The AER considers that the suggestion has merit. The AER notes that ETSA Utilities' capex forecasts already reflect real cost changes (as discussed in section 7.8.3). A significant proportion of ETSA Utilities' capex is accounted for by labour costs. The AER notes that the labour cost escalation rates that the AER determines for ETSA Utilities are based on a separate independent assessment and include efficiency improvements over time. As a result, the significant labour component of ETSA Utilities' capex forecasts will account for efficiency improvements over the next regulatory control period.

The AER also notes that with a weighted average price cap, ETSA Utilities has an incentive to reduce its costs (for example by improving its efficiency) over the course of the next regulatory control period because reduced costs will lead to increased profits. Over time, customers will benefit from such cost savings because the AER will take account of these in setting prices for the following regulatory control period.

Having considered ETSA Utilities' forecast capex program and cost estimation processes, advice from PB, ETSA Utilities' consultant and submissions, the AER is satisfied that ETSA Utilities' 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 ETSA Utilities' cost estimation processes are consistent with the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors. In particular, the AER considers that the benchmarking of ETSA Utilities' unit costs against those calculated by ETSA Utilities' consultant satisfies the capex factor (clause 6.5.7(e)(4)) that the AER have regard for the benchmark capex that would be incurred by an efficient DNSP over the regulatory control period.

7.8.3 Application of input cost escalators

This section examines whether the cost escalators used by ETSA Utilities to develop its capex proposal reflect a realistic expectation of input costs required to meet the capex objectives, in the context of determining whether the AER is satisfied that

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350 PB, *Report – ETSA Utilities,* October 2009, pp. 28 and 47.
351 PB, *Report – ETSA Utilities,* October 2009, pp. 28 and 47.

ETSA Utilities' forecast capex reasonably reflects the capex criteria. While cost escalation affects capex sub-categories discussed in this chapter, the impacts of cost escalation, including any adjustments required by the AER, are treated in aggregate in this section only.

ETSA Utilities regulatory proposal

ETSA Utilities stated that many of the costs of electrical utilities do not increase in ways that reflect the CPI basket of goods. As a result, ETSA Utilities engaged two consultants to develop forecasts of the growth of its key cost inputs of labour, services and materials.[352]

ETSA Utilities engaged BIS Shrapnel to forecast real growth in ETSA Utilities' labour costs and services costs[353] and SKM to forecast real growth in ETSA Utilities' material costs, including aluminium, copper, steel, oil and concrete.[354] The approach to calculating cost escalators taken by each of these consultants is discussed in detail in appendix G of this draft decision.

The materials escalation rates that SKM was required to develop were used by ETSA Utilities to populate an internal cost escalation model.[355] SKM found that ETSA Utilities' model used the same methodology that had been used by ElectraNet (which was ultimately accepted by the AER) in its submission to the AER.[356] SKM also established that all labour and materials components of asset cost escalation had been separated within the ETSA Utilities model, consistent with preferences previously communicated by the AER.[357]

SKM was also required by ETSA Utilities to develop weighting factors relating to how much each of the materials cost drivers was considered to influence each class of network assets.[358] SKM then used a set of network category weightings provided by ETSA Utilities, which indicated the proportion that each asset category contributed to the total distribution network, to develop a single series of materials costs escalation rates.[359]

The cost escalation rates applied by ETSA Utilities to each category of costs are presented in table 7.4. The labour cost escalation rates apply to the costs associated with ETSA Utilities' employees and supplementary labour contractors in delivering standard control services. The materials cost escalation rates apply to the costs of distribution equipment such as conductor, cable, insulators, circuit breakers and transformers, as well as raw materials for the production of poles, and other items of

352 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 102–103.
353 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 103–104.
354 ETSA Utilities, *Regulatory proposal*, July 2009, p. 105.
355 ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.5, SKM: Distribution asset cost escalation rates, p. 3.
356 ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.5, SKM: Distribution asset cost escalation rates, p. 3.
357 ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.5, SKM: Distribution asset cost escalation rates, p. 3.
358 ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.5, SKM: Distribution asset cost escalation rates, p. 4.
359 ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.5, SKM: Distribution asset cost escalation rates, p. 4.

equipment such as vehicles, plant and tools. The services cost escalation rates apply to the costs of other, predominantly labour-based, services purchased by ETSA Utilities in order to deliver its services, for example, tree cutting, meter reading and civil works.[360]

Table 7.4: Forecast real increases for ETSA Utilities' key cost categories (%)

	2010–11	2011–12	2012–13	2013–14	2014–15	Average
Labour costs	2.7	3.8	3.5	3.3	3.5	3.3
Services costs – construction related	1.1	1.7	2.5	2.5	1.5	1.9
Service costs – other outsourced work	0.8	0.5	0.8	1.0	1.0	0.8
Materials costs	1.7	2.0	1.4	1.4	1.3	1.6

Source: ETSA Utilities, *Regulatory proposal*, July 2009, pp. 103–104

ETSA Utilities stated that it applied these forecasts of real growth in labour, materials and services costs to relevant cost lines within its capex model from financial year 2009–10 (given that its base year for its cost build ups is 2008–09).[361]

ETSA Utilities indicated that the application of escalation rates within its model has been reviewed by SKM and KPMG and assessed as being appropriate.[362] The impact of ETSA Utilities' proposed input cost escalation rates are in table 7.5.

Table 7.5: Impact of ETSA Utilities' real cost escalation

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base capex ($2007–08 million)	357.3	428.7	409.7	383.8	364.8	1944.2
Escalation adjustment ($ million)	20.8	35.4	44.0	51.5	57.9	209.6
Inflation adjustment ($ million)	28.4	34.8	34.0	32.6	31.7	161.5
Total capex ($2009–10 million)	406.5	498.9	487.8	467.9	454.3	2315.3

Source: ETSA Utilities, *Regulatory Proposal*, July 2009, attachment E.1.

Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of ETSA Utilities' capex proposal. PB was not required to assess forecast rates of growth in ETSA Utilities' input costs. However, as part of its review, PB was

360 ETSA Utilities, *Regulatory proposal*, July 2009, p. 103.
361 ETSA Utilities, *Regulatory proposal*, July 2009, p. 103.
362 ETSA Utilities, *Regulatory proposal*, July 2009, p. 103.

required to ensure that forecast changes in input costs have been appropriately reflected in the cost escalation calculations performed by ETSA Utilities in forecasting capex.

PB reviewed the approach applied by SKM to determine appropriate materials cost escalators for ETSA Utilities' capex forecasts, and in particular SKM's approach to the weighting of input commodities within asset classes and the weighting of asset classes within ETSA Utilities' total assets.[363]

PB considered that the weightings of input commodities within asset classes were appropriate as they align with PB's expectations and do not appear to be significantly skewed towards any particular input commodity.[364] PB confirmed that the weightings of asset classes used by SKM reflect the weightings within ETSA Utilities' network and considered them suitable for use in the application of cost escalators.[365] As a result of these considerations, PB concluded that SKM's approach results in an escalation index for materials costs that is representative of ETSA Utilities' network and is suitable for application to ETSA Utilities' forecast capex.[366]

PB also reviewed the reasonableness of the methodology ETSA Utilities used to apply the materials cost escalators, as well as escalators developed for labour, general services and construction services.

PB noted that in order to apply the escalators, ETSA Utilities disaggregated its forecast capex into the same categories as the escalators and directly applied the relevant escalator. PB identified the following two issues with ETSA Utilities modelling of this process:[367]

- While input values are in 2007–08 dollars, the model ignores the 2008–09 escalators and starts escalation from 2009–10 onwards. Given that the 2008–09 materials escalator is strongly negative, this omission has the effect of over estimating capex for the next regulatory control period. PB noted ETSA Utilities' comments that it took the approach it did to ensure consistency with cost escalation for opex and that the approach may not align with the real cost increases over the period. PB stated that it did not support the use of 2008–09 as the base year for capex escalation, given the different approaches ETSA Utilities took to develop its opex and capex forecasts. On this basis, PB concluded that ETSA Utilities' application of real cost escalators in the development of its capex forecast is not efficient and the real annual cost escalators for 2008–09 should also be applied.

- A 2.5 year period was used to inflate from 2007–08 dollars to 2009–10 dollars rather than a 2 year period. ETSA Utilities stated that its bottom–up capex estimates were derived from costs in the 2007–08 financial year and have subsequently been treated as December 2007 costs in ETSA Utilities' modelling.

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363 PB, *Report – ETSA Utilities*, October 2009, p. 10.
364 PB, *Report – ETSA Utilities*, October 2009, p. 10.
365 PB, *Report – ETSA Utilities*, October 2009, p. 10.
366 PB, *Report – ETSA Utilities*, October 2009, p. 10.
367 PB, *Report – ETSA Utilities*, October 2009, pp. 11–12.

> PB noted that the costs are identified as 2008 costs in ETSA Utilities' Asset Management Plan (AMP) and costing spreadsheets and that unit costs are specifically stated to have been escalated from 2007 costs to 2008 costs in ETSA Utilities' unit cost report. On this basis, PB concluded that ETSA Utilities' application of CPI escalation in the development of its capex forecasts is not efficient and that ETSA Utilities' bottom–up estimates should be treated as June 2008 costs.

PB calculated that correction of these issues results in a 6.0 per cent reduction in forecast capex over the next regulatory control period. The annual and total adjustments to ETSA Utilities' capex recommended by PB are shown in table 7.6.

Table 7.6: PB recommended adjustments to capex to correct for cost escalation errors

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA proposed gross capex	493.9	592.7	572.7	562.8	550.3	2772.4
Adjustment for real escalation 2007–08 to 2008–09	–19.7	–22.1	–22.0	–21.5	–20.4	–105.7
Adjustment for CPI inflation 2007–08 to 2009–10	–10.6	–12.8	–12.3	–12.1	–11.9	–59.7
Total adjustment ($m)	–30.3	–34.8	–34.4	–33.6	–32.3	–165.4
Total adjustment (%)	–6.1	–5.9	–6.0	–6.0	–5.9	–6.0

Source: PB, *Report – ETSA Utilities*, October 2009, p. 12.

AER considerations

As noted above, the AER assessed forecast rates of growth in ETSA Utilities' input costs and PB was required to ensure that these forecasts have been appropriately reflected in the cost escalation calculations performed by ETSA Utilities.

The AER's detailed consideration and conclusions on ETSA Utilities' input cost escalators, and the methodologies underpinning those escalators, are set out at appendix G to this draft decision. The AER has not accepted the methodologies used to develop ETSA Utilities' real cost escalators.

ETSA Utilities engaged BIS Shrapnel to prepare forecasts of its real wage growth for the period 2008–09 to 2014–15.[368] BIS Shrapnel prepared a single set of labour cost escalation rates to apply to ETSA Utilities' internal labour forecasts for the period. In developing its labour cost growth escalators, BIS Shrapnel considered macro-economic factors and ETSA Utilities' specific circumstances, including contract terms and historical and future conditions.[369] BIS Shrapnel's forecasts indicate stronger wage growth in the South Australian utilities sector compared to other sectors, due to stronger demand for labour, competition for skilled labour and the impact of planned

[368] BIS Shrapnel, *Outlook for wages, contract services and customer connections expenditure to 2014–15, South Australia*, May 2009.

[369] ETSA Utilities, *Regulatory proposal*, July 2009, p. 103.

capex programs planned by network infrastructure businesses in South Australia and nationally.[370] It also noted that the structural initiatives adopted by ETSA Utilities also contribute to wages growth that is higher than the South Australian average.

As discussed in detail in appendix G, the AER does not consider ETSA Utilities' escalation rates for labour costs are acceptable because, amongst other things:

- the forecasts developed by BIS Shrapnel in May 2009 are no longer based on the latest available information and expectations, specifically, expectations regarding the macro economic climate which underpin the forecasts

- the internal labour growth forecasts explicitly reflect the impact of ETSA Utilities' internally determined performance and incentive initiatives, including bonus payments, which the AER considers have not been demonstrated to be efficient by ETSA Utilities

- the forecasts do not appear to accurately consider the actual composition of its internal and contract service labour resources by labour type.

The AER has reviewed the approach applied by SKM to determine appropriate materials cost escalators for ETSA Utilities' capex forecasts. The AER considers that the approach adequately reflects the weightings of input commodities and asset classes within ETSA Utilities' network, and could therefore be expected to produce a realistic expectation of changes in ETSA Utilities' materials costs. The AER notes that PB reached the same conclusion. However, as discussed in detail in appendix G, the AER does not consider that the materials escalation rates themselves are acceptable because they do not reflect the most up to date market–based forecasts of future materials costs.

Regarding the application of escalators by ETSA Utilities in developing its capex forecasts, the AER considers that it is not appropriate for ETSA Utilities to omit escalating real costs in 2008–09, given that its base costs are for 2007–08. ETSA Utilities itself indicated that it appreciated its approach may understate its real cost increases, but considered it was desirable to retain consistency between the capex and opex models.[371] The AER does not consider that any perceived benefit from modelling consistency outweighs properly reflecting the cost changes that occurred in 2008–09. The AER therefore requires ETSA Utilities' to apply real cost escalators for 2008–09 in forecasting capex.

The AER considers that requiring ETSA Utilities to correctly apply real cost escalation to its capex forecasts, which includes accounting for significant real cost decreases in 2008–09, addresses concerns in submissions regarding real cost increases in ETSA Utilities' capex forecasts.

The AER has reviewed ETSA Utilities' escalation model and confirmed PB's finding that 2007–08 base year costs have been escalated by 2.5 years to derive the June 2010

370 BIS Shrapnel, *Outlook for wages, contract services and customer connections expenditure to 2014–15, South Australia*, May 2009, p. 2.

371 ETSA Utilities, response to PB question PB.ETS.EM.67, 20 August 2009.

costs upon which ETSA Utilities' capex forecasts are based.[372] However, a range of sources indicate that ETSA Utilities' base costs reflect 2007 costs escalated to 2008 costs.[373] The AER considers that it is not appropriate to derive June 2010 costs by applying 2.5 years of cost escalation to 2008 base year costs. As a result, the AER requires ETSA Utilities to escalate its base year costs for two years rather than 2.5 years in forecasting capex.

The AER requested ETSA Utilities to model the impacts of the AER's decisions in relation to cost escalation. ETSA Utilities advised that the adjustment to forecast capex is a reduction of $107 million ($2009–10).

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 ETSA Utilities' cost escalation reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities' proposed capex by $107 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.

7.8.4 Review by expenditure type

This section examines the scope, timing and costs of ETSA Utilities' proposed capex by major investment category in the context of determining whether the AER is satisfied that ETSA Utilities' forecast capex reasonably reflects the capex criteria.

7.8.4.1 Demand driven capex

ETSA Utilities regulatory proposal

ETSA Utilities forecast demand driven capex of $1457 million ($2009–10) for the next regulatory control period. Total demand driven capex, which includes both capacity related expenditure and customer connections expenditure, represents approximately 53 per cent of the total forecast capex program. ETSA Utilities' demand driven capex is forecast to increase by approximately 93 per cent from the current regulatory control period.[374] Table 7.7 sets out ETSA Utilities' proposed demand driven capex for the next regulatory control period.

[372] ETSA Utilities, *Regulatory proposal*, July 2009, confidential attachment E.1, SEM capex model version 7.2, cells C55 and C56 of the 'R6 ($2010)' sheet.
[373] ETSA Utilities, *Regulatory proposal*, July 2009, confidential attachments CX001-summary sheets, CX009-unit cost methodology, E.9-Distribution System Planning Report.
[374] Derived from ETSA Utilities RIN proforma 2.2.1.

Table 7.7: ETSA Utilities proposed demand driven capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Capacity	146.6	194.4	147.6	144.6	142.6	775.7
Customer connections	130.6	139.1	127.6	141.0	143.0	681.3
Total gross demand driven capex	277.3	333.4	275.3	285.5	285.5	1457.0
Customer contributions	–87.4	–93.8	–85.0	–95.0	–96.0	–457.1
Total net demand driven capex	189.8	239.6	190.3	190.6	189.5	999.8

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN proforma 2.2.1.
Note: Totals may not add due to rounding.

Capacity

Approximately 53 per cent of the proposed gross demand driven capex is attributed to capacity related expenditure required to upgrade the existing network in response to peak demand growth. ETSA Utilities' capacity related capex includes low voltage related works to upgrade distribution transformers and low voltage mains, as well as feeder, sub–transmission, and substation capacity works.[375] ETSA Utilities has forecast annual network peak demand growth of 2.6 per cent over the next regulatory control period.[376]

ETSA Utilities' capacity related expenditure is forecast to increase by approximately 266 per cent from the current regulatory control period, and is a major driver of the overall increase in capex. The proposed increase in expenditure has been attributed to revised low voltage planning criteria, changes to the South Australian electricity transmission code requiring downstream work on ETSA Utilities' distribution network, and the need to alleviate forecast network constraints.[377]

ETSA Utilities engaged PB Power to review the distribution system planning report which forms the basis of its proposed capacity related expenditure in the next regulatory control period. PB Power found that ETSA Utilities' documented planning procedure is robust and comprehensive enough to meet ETSA Utilities' obligations. Further, PB Power found that ETSA Utilities' risk management process and planning criteria are generally in line with good industry practice.[378]

Customer connections

Approximately 47 per cent of ETSA Utilities' proposed gross demand driven capex relates to customer connection expenditure. This expenditure is associated with additions, upgrades or alterations resulting from the requirements of specific

[375] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 111–113.
[376] ETSA Utilities, *Regulatory proposal*, July 2009, p. 101.
[377] ETSA Utilities, *Regulatory proposal*, July 2009, p. 111.
[378] PB Power, *Review of distribution system planning report*, September 2008, p. 3.

customers, and includes minor, medium and major customer connections, connections of new housing developments, and rebates for assets gifted to ETSA Utilities.[379]

ETSA Utilities engaged BIS Shrapnel to develop the forecast for customer connection expenditure for the next regulatory control period. BIS Shrapnel developed the forecast using a range of economic inputs including expected approvals and commencements for new houses and other dwellings, residential additions and alterations approvals, non–residential building commencements, and other known South Australian project commencements.[380]

Customer connection expenditure is forecast to increase by approximately 25 per cent from the current regulatory control period. BIS Shrapnel attributed the forecast increase in expenditure largely to a substantial increase in major customer connection expenditure underpinned by a range of significant public sector projects.[381]

ETSA Utilities estimated that it will recover approximately 67 per cent of gross customer connections expenditure through contributions from customers, in accordance with the current *Electricity Distribution Code* and ESCOSA guidelines. ETSA Utilities' forecast of the level of customer contributions is based on historical levels of contributions for each customer connection expenditure category.[382]

Consultant review

PB reviewed ETSA Utilities' proposed demand driven capex for the next regulatory control period, including both the capacity related and customer connection capex. PB considered the drivers of these categories of expenditure and the application of key policies and procedures including ETSA Utilities' planning criteria, options analysis and cost estimation procedures. PB also reviewed ETSA Utilities' consideration of non–network alternatives and the application of the demand forecast, and specifically examined the low voltage network upgrade and major customer connections programs.[383]

A review of ETSA Utilities' peak demand forecasts was undertaken for the AER by AEMO.[384] Additionally, McLennan Magasanik Associates (MMA) reviewed ETSA Utilities' forecast customer numbers for the AER.[385] The outcomes of these reviews are discussed in detail in chapter 6. In summary, AEMO and MMA found ETSA Utilities' peak demand and customer number forecasts to be reasonable. PB therefore did not recommend any demand forecast related adjustment to ETSA Utilities' proposed demand driven capex.[386]

PB found ETSA Utilities' planning criteria to be prudent and in accordance with good electricity industry practice. PB considered the planning criteria to be appropriately

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[379] ETSA Utilities, *Regulatory proposal*, July 2009, p. 116.
[380] ETSA Utilities, *Regulatory proposal*, July 2009, p. 117.
[381] BIS Shrapnel, *Outlook for wages, contract services and customer connections expenditure to 2014/15: South Australia*, May 2009, pp. 2–3.
[382] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 116–117.
[383] PB, *Report – ETSA Utilities*, October 2009, p. 26.
[384] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009.
[385] MMA, *Review of ETSA Utilities customer number forecasts*, 21 September 2009.
[386] PB, *Report – ETSA Utilities,* October 2009, p. 40.

applied through the planning process and suitable for forecasting ETSA Utilities' demand driven capex investment.[387] ETSA Utilities' revised planning approach to low voltage capacity was considered separately by PB, as discussed below.

PB found that the cost estimation process used by ETSA Utilities was based on reasonable building block costs, transparently applied and appropriate for forecasting ETSA Utilities' capacity expenditure.[388]

PB reviewed several examples of ETSA Utilities' options analysis for addressing identified network constraints and found that ETSA Utilities considers a reasonable range of options, including non–network alternatives, in its capacity planning decisions. PB concluded that despite the absence of formal business case documentation that would not be finalised until close to the approval of project expenditure, the options analyses for the reviewed network augmentation projects were available to adequately support the proposed solution.[389]

In reviewing the extent to which efficient non–network alternatives are considered by ETSA Utilities to address identified network constraints, PB found that economically viable non–network alternatives are considered as a matter of course before applying network solutions.[390] PB noted that assessment is made to find out whether a non–network alternative is more efficient than a more traditional network augmentation option. PB noted evidence of ETSA Utilities' active development and implementation of demand management practices, and concluded that ETSA Utilities' consideration of non–network solutions and demand management opportunities was consistent with good electricity industry practice.[391]

PB reviewed ETSA Utilities' application of its demand and customer number forecasts in the build up of the proposed capacity and customer connection capex. PB found that ETSA Utilities had applied the demand and customer connection forecasts appropriately in determining the forecast demand driven capex.[392]

ETSA Utilities' revised approach to low voltage capacity planning was specifically reviewed by PB. PB concluded that the risk assessment for the low voltage capacity upgrade program overstated the risk to the low voltage network and does not support the full scope of the proposed program.[393] Further, PB found that ETSA Utilities' proposed low voltage planning criteria were more conservative than those applied by other Australian DNSPs, and the loading assumptions and volume forecast led to an overstated scope of work.[394]

PB concluded that the proposed capex for the low voltage capacity upgrade program was not prudent or efficient.[395] However, PB recognised that recent heatwaves had

[387] PB, *Report – ETSA Utilities*, October 2009, p. 27.
[388] PB, *Report – ETSA Utilities*, October 2009, p. 28.
[389] PB, *Report – ETSA Utilities*, October 2009, p. 29.
[390] PB, *Report – ETSA Utilities*, October 2009, p. 30.
[391] PB, *Report – ETSA Utilities*, October 2009, p. 31.
[392] PB, *Report – ETSA Utilities*, October 2009, pp. 29–30.
[393] PB, *Report – ETSA Utilities*, October 2009, p. 33.
[394] PB, *Report – ETSA Utilities*, October 2009, p. 36.
[395] PB, *Report – ETSA Utilities*, October 2009, p. 36.

resulted in constraints that a prudent network operator would seek to address to maintain service standards. PB therefore considered that a prudent and efficient approach would reflect a business as usual level of expenditure plus additional targeted augmentation expenditure to address identified constraints.[396] PB recommended a reduction of $102 million, to a business as usual level of expenditure plus additional expenditure equating to the replacement of 51 distribution transformers per year, in line with the number of failures experienced in recent heatwaves.[397]

PB also made a specific review of ETSA Utilities' major customer connections program, which accounts for the majority of total proposed customer connection capex. ETSA Utilities' cost estimation process and project likelihood assessments were found to be reasonable. However, PB identified an unsupported contingency of $31 million for unidentified projects in the next regulatory control period.[398] PB recommended that this amount be removed from ETSA Utilities' customer connection capex proposal, as it considered that the approach used by ETSA Utilities to develop its major customer connection forecast already implicitly allows for unknown projects, and no further contingency is required.[399]

AER considerations

The AER reviewed ETSA Utilities' demand driven capex proposal for the next regulatory control period, including both capacity related and customer connection capex. The AER has considered the documentation provided by ETSA Utilities in support of its regulatory proposal, and sought advice from PB about the prudence and efficiency of the proposed expenditures.

The AER notes that demand driven capex accounts for approximately 53 per cent of the total forecast capex program and is forecast to increase by 93 per cent compared to the current regulatory control period.[400] The AER notes that capacity related expenditure is the major contributor to this increase in demand driven expenditure, with a forecast increase of 266 per cent in this category accounting for 80 per cent of the total forecast increase in gross demand driven capex from the current regulatory control period.[401]

The AER notes that ETSA Utilities has estimated that it will recover approximately 67 per cent of gross customer connections expenditure through contributions from customers, and that this forecast is based on historical levels of contributions for each customer connection expenditure category.[402] The AER considers this forecasting approach based on observed historical ratios is appropriate given the contributions regime will remain unchanged in the next regulatory control period. This approach

396 PB, *Report – ETSA Utilities*, October 2009, p. 36.
397 PB, *Report – ETSA Utilities*, October 2009, pp. 36–37.
398 PB, *Report – ETSA Utilities*, October 2009, pp. 38–40.
399 PB, *Report – ETSA Utilities*, October 2009, p. 39.
400 Derived from ETSA Utilities RIN pro forma 2.2.1.
401 Derived from ETSA Utilities RIN pro forma 2.2.1.
402 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 116–117.

should remedy the significant under–estimation of customer contributions levels observed in the current regulatory control period.[403]

ETSA Utilities identified continued peak demand growth as a key driver of demand driven expenditure, and forecast annual peak demand growth of 2.6 per cent over the next regulatory control period.[404] The AER received submissions from the EUAA and ECCSA questioning the relationship between forecast demand and customer number growth rates which are lower than, or consistent with, historical rates and the proposed significant increases in capacity and customer connection related capex.[405]

The AER sought advice from AEMO and MMA on the reasonableness of ETSA Utilities peak demand, sales and customer number forecasts. PB provided advice about the application of the forecasts in ETSA Utilities' preparation of its capex proposal. The AER notes the advice from AEMO and MMA that ETSA Utilities' peak demand and customer number forecasts are reasonable[406], and PB's view that ETSA Utilities has applied its demand and customer number forecasts appropriately in determining the forecast demand driven capex.[407] The AER is therefore satisfied that ETSA Utilities' forecast demand driven capex reasonably reflects a realistic expectation of the demand forecast required to achieve the capex objectives set out in the NER.

The AER received a number of submissions commenting on the extent to which ETSA Utilities has proposed to utilise non–network alternatives to address identified network constraints in the next regulatory control period.[408] The AER reviewed the extent to which ETSA Utilities 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.

The AER notes PB's finding that ETSA Utilities considers economically viable non–network alternatives as a matter of course before applying network solutions, and that it assesses the relative efficiency of non–network alternatives and traditional network augmentation options.[409] PB concluded that ETSA Utilities' consideration of non–network solutions and demand management opportunities was consistent with good electricity industry practice.[410]

The AER found that ETSA Utilities had specifically identified examples of non–network expenditure totalling approximately $19 million within the capacity

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403 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 116–117.

404 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 101 and 109.

405 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 19; and EUAA, *Submission to the AER*, August 2009, p. 11.

406 AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October 2009, p. XIII; and MMA, *Review of ETSA Utilities customer number forecasts*, 21 September 2009, p. 3.

407 PB, *Report – ETSA Utilities*, October 2009, pp. 29–30.

408 Business SA, *Submission to the AER*, August 2009, p.7; SACOSS, *Submission to the* AER, August 2009, pp. 3–4; COTA, *ETSA distribution price review*, August 2009, p. 5; UCW, *Distribution price review for South Australia*, p. 14; and EUAA, *Submission to the AER*, August 2009, p.11.

409 PB, *Report – ETSA Utilities*, October 2009, p. 30.

410 PB, *Report – ETSA Utilities*, October 2009, p. 31.

related capex proposal.[411] In addition, the AER notes that all capacity related projects estimated to cost in excess of $2 million are assessed to determine instances where a non–network alternative may be a viable solution to an identified network constraint.[412] The AER notes that ETSA Utilities has undertaken a number of Requests for Proposals in the current regulatory control period, seeking proposals for non–network solutions to remedy network constraints.[413] In regard to these public processes, the AER recognises that the extent to which ETSA Utilities is then able to make provision for efficient non–network alternatives is dependent upon responses which bring forward viable non–network solutions for consideration.

On the basis of its review, and the advice from PB, the AER is satisfied that ETSA Utilities has appropriately considered, and made provision for, efficient non–network alternatives in its demand driven capex proposal, and that ETSA Utilities' approach is in line with good electricity industry practice in this regard.

In relation to ETSA Utilities' other policies and procedures for planning the proposed demand driven capex, the AER notes PB's findings that:

- ETSA Utilities' planning criteria are prudent, in accordance with good electricity industry practice, and appropriately applied through the planning process[414]

- the options analysis process underpinning capacity planning decisions considers a reasonable range of options, including non–network alternatives, and for the specific projects reviewed adequately supported the proposed solution[415]

- the cost estimation process used by ETSA Utilities is based on reasonable building block costs, transparently applied and appropriate for forecasting ETSA Utilities' capacity expenditure[416]

- ETSA Utilities has a well-developed documentation framework that demonstrates thorough capital governance practices, consistent with good electricity industry practice.[417]

The AER considers that these findings, together with AEMO's findings as to the reasonableness of ETSA Utilities' demand forecast, support a view that the need, timing and efficiency of the proposed expenditures has been appropriately established by ETSA Utilities. The AER is therefore satisfied that, with the exception of the specific areas of qualification noted below, the forecast demand driven capex reflects the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capex objectives set out in the NER.

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411 ETSA Utilities, *Regulatory proposal*, July 2009, RIN18 Consideration on non–network alternatives, p. 1.
412 ETSA Utilities, *Regulatory proposal*, July 2009, p. 113.
413 ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.11 – Projects for which Regulatory Test has been undertaken, June 2009, p. 1.
414 PB, *Report – ETSA Utilities*, October 2009, p. 27.
415 PB, *Report – ETSA Utilities*, October 2009, p. 29.
416 PB, *Report – ETSA Utilities*, October 2009, p. 28.
417 PB, *Report – ETSA Utilities*, October 2009, p. 23.

The AER notes that, despite its findings as to the appropriateness of ETSA Utilities' planning criteria, capex governance, options analysis and cost estimation procedures, PB has recommended that specific adjustments be made to the proposed demand driven capex in two areas: the low voltage network upgrade program and major customer connections capex.[418]

The AER notes PB's assessment that the risk assessment underpinning the low voltage network upgrade program overstates the risk, and that ETSA Utilities' proposed low voltage planning criteria are more conservative than those applied by other Australian DNSPs. The AER considers that the full scope of the proposed program has not been appropriately justified given ETSA Utilities' use of inferred rather than actual load assumptions and the resulting impact on volume forecasts. For example, the AER notes PB's advice that of ETSA Utilities' sample of 168 distribution transformer monitoring points, 65 would qualify for inclusion in the forecast augmentation program based on ETSA Utilities' methodology despite actual monitoring results indicating they were below 100 per cent loaded during the extreme 2009 heatwave event.[419]

PB recommended that ETSA Utilities' low voltage network capex be determined on the basis of business as usual expenditure plus additional targeted expenditure to address actual identified network constraints.[420] The AER notes PB's approach to determining a business as usual level of expenditure, based on the average historical planned transformer and line augmentation capex. PB also recommended additional expenditure to allow for the replacement of a further 51 transformers per annum, consistent with historical levels of overloaded transformer failures.[421] The AER considers that such an approach, which allows for a level of capex over and above historical expenditure to address constraints arising from extreme heat events, represents a reasonable approach to determining a prudent and efficient level of expenditure in the absence of information supporting the full scope of the proposed program. The AER requested ETSA Utilities model the impact of the AER's decision on the low voltage network capex. ETSA Utilities advised that the adjustment to forecast demand driven capex is a reduction of $103 million ($2009–10).

The AER notes that PB recommended that an unsupported contingency of $31 million for unidentified customer connection projects over the next regulatory control period be removed from ETSA Utilities' customer connection capex proposal.[422] The AER has reviewed ETSA Utilities' methodology for developing the major customer connection forecast, whereby projects are included on the basis of a 50 per cent probability of proceeding.[423] The AER considers that this methodology implicitly accounts for contingencies, and that no further contingency is required. The AER requested ETSA Utilities model the impact of the AER's decision on this aspect of customer connection capex, including the offsetting impact of this capex adjustment

[418] PB, *Report – ETSA Utilities*, October 2009, p. 41.
[419] PB, *Report – ETSA Utilities*, October 2009, p. 36.
[420] PB, *Report – ETSA Utilities*, October 2009, p. 36.
[421] PB, *Report – ETSA Utilities*, October 2009, pp. 36–37.
[422] PB, *Report – ETSA Utilities*, October 2009, p. 40.
[423] PB, *Report – ETSA Utilities*, October 2009, p. 39.

on forecast customer contributions. ETSA Utilities advised that the adjustment to net forecast demand driven capex is a reduction of $8 million ($2009–10).

In relation to the submission received from UCW, the AER notes that two of the projects/programs which UCW suggested be excluded from a reasonable capex proposal relate to demand driven capex:[424]

- major infrastructure support projects (major customer connections)
- City West transmission connection point project.

As discussed above, the AER considers the expenditure associated with these projects to be prudent and efficient, with the exception of the major customer connections contingency. The AER considers that it would not be prudent for ETSA Utilities to make no allowance for work it is required to perform in accordance with its licence conditions or as a result of the *Electricity Transmission Code*, such as customer connection projects and the City West project. The AER notes in this regard Business SA's view that priority should be given to the connection of new major projects and development initiatives, and the SA Energy Minister's submission which supported the proposed City West works.[425]

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 ETSA Utilities' demand driven capex proposal reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities' proposed net demand driven capex by $111 million ($2009–10) 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.

7.8.4.2 Asset replacement capex

ETSA Utilities regulatory proposal

ETSA Utilities forecast an amount of $467 million ($2009–10) for replacement capex during the next regulatory control period, an increase of 202 per cent (in real terms) compared to the current regulatory control period. Forecast asset replacement capex represents approximately 17 per cent of ETSA Utilities' total forecast capex program. Table 7.8 sets out the proposed asset replacement capex for each year of the next regulatory control period.

Table 7.8: ETSA Utilities proposed asset replacement capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement	79.7	91.4	96.8	98.9	99.9	466.8

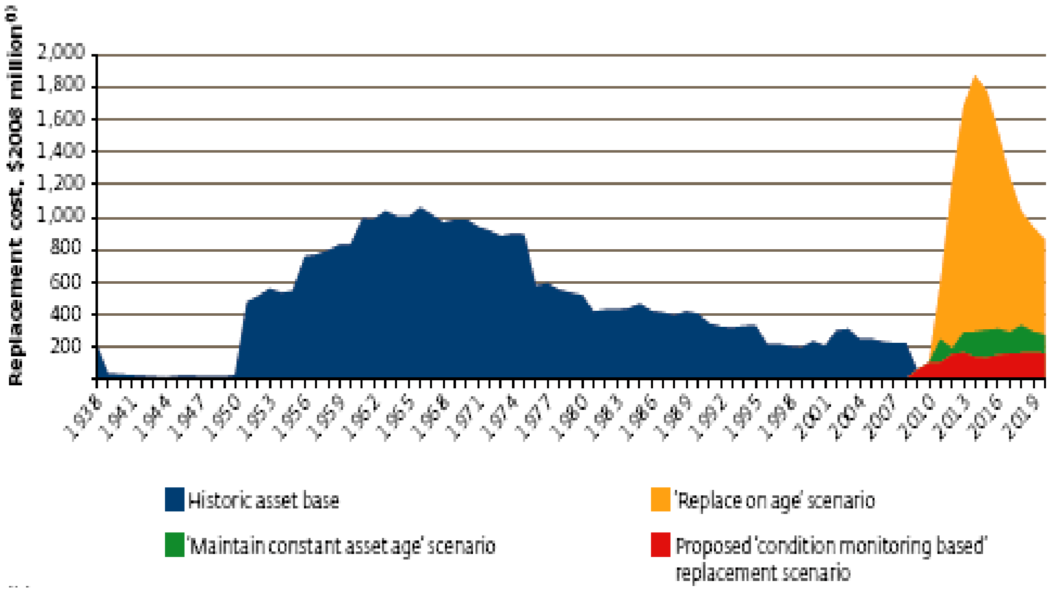
Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 119.

[424] UCW, *Distribution price review for South Australia*, pp. 15–16.
[425] Business SA, *Submission to the AER*, August 2009, p. 6; and SA Energy Minister, *Submission to the AER*, September 2009, p. 2.

ETSA Utilities stated that its asset replacement capex is targeted at the replacement of assets following failure or on the basis of condition or age. It noted that a significant portion of its assets are approaching the end of their engineering lives. Further, it stated that it can not continue its current 'replace on failure' approach without increasing both the risk of unplanned equipment failure and the consequent reliability impacts to unacceptable levels.[426]

ETSA Utilities stated that it has reviewed its asset management plans and decided to adopt an asset management policy and underlying strategies that reflect increased condition monitoring and consequent increased condition based asset replacement. The new plans and strategies are the drivers for the increased asset replacement capex over the next regulatory control period. ETSA Utilities stated that its proposed asset replacement strategy is both prudent and efficient resulting in lower levels of asset replacement capex than would be required if replacement were based on asset age alone, as shown in figure 7.3. However, it noted that its proposed strategy will still result in average asset age increasing from 36 to 39 years and the proportion of assets with ages in excess of their technical lives will increase to more than 20 per cent, highlighting the need for the strategy to be applied over the next 15 to 20 years to reduce average asset age.[427]

Figure 7.3 ETSA Utilities asset age profile and proposed asset replacement capex



Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 120.

ETSA Utilities stated that it has reviewed each of its asset classes to determine risk and known condition. Where condition is unknown, age has been used as the lead indicator of condition. ETSA Utilities noted that its condition monitoring strategies are not yet fully implemented and adequate condition–based information is not yet available for many asset types. ETSA Utilities engaged Maunsell to review its asset

426 ETSA Utilities, *Regulatory proposal*, July 2009, p. 119.
427 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 119–120.

management plans against the requirements in the NER and standard industry practice. Maunsell's key findings included:[428]

- the key assumptions and methodologies used in the asset management plans to determine numbers were generally valid and support NER compliance
- the asset management plans are sufficient to comply with customer service obligations and meet relevant regulations and standards
- the asset management plans are generally in accordance with good industry practice
- ETSA Utilities plans resulted in higher residual risk compared to industry practice and recommended an accelerated asset replacement program.

ETSA Utilities stated that it considered that in most instances the increased risks identified by Maunsell were partially mitigated by the increase in condition monitoring and therefore acceptable, at least in the short term.[429]

Consultant review

PB reviewed ETSA Utilities' policies and procedures including its asset replacement strategy and several asset replacement categories in detail. PB considered a significant proportion of ETSA Utilities' proposed asset replacement capex for the next regulatory control period was not prudent and efficient and recommended adjustments.

Policies and procedures

PB noted that in the past ETSA Utilities adopted a replace on failure approach to asset management which is not uncommon within the industry. It managed the risks of this approach through network redundancy under its planning criteria, the use of mobile substations, feeder capacity management and monitoring and testing of essential assets such as power transformers.[430]

While ETSA Utilities historically managed the risks associated with its assets, it recently adopted a revised asset management approach based on asset condition. PB considered that the need for such a significant change in approach should be clearly demonstrated through a sound economic evaluation of the risks, costs and benefits associated with various options. PB requested the business case that supported ETSA Utilities decision to adopt the proposed asset management strategy. PB stated that the documentation asserted, but did not demonstrate, that the proposed strategy was the least cost or highest NPV when compared to its business as usual approach (that is, its current replace on failure approach). PB also found that ETSA Utilities' asset management plans included limited consideration of cost efficiency or non–replacement options.[431]

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[428] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 120–121.
[429] ETSA Utilities, *Regulatory proposal*, July 2009, p. 121.
[430] PB, *Report – ETSA Utilities*, October 2009, p. 44.
[431] PB, *Report – ETSA Utilities*, October 2009, p. 44.

PB reviewed ETSA Utilities capital budgeting procedures and concluded that ETSA Utilities risk management framework is well implemented at a corporate level. Further, it noted that there is a strong understanding across the business of the need for risk based justification for capital budgeting decisions. PB identified a number of issues with the application of ETSA Utilities risk assessment processes. It concluded that while the risk assessment process ETSA Utilities applied in developing its forecast capex is appropriate for high level project ranking at a corporate level, the detailed assessment of risk within a project or program is simplistic and does not ensure efficient expenditure.[432]

In planning replacement capex, PB considered that the effective evaluation of replacement, refurbishment, run to failure and increased monitoring strategies is important to ensure the full range of options are considered. PB noted that there was limited specific consideration of replacement versus refurbishment options in ETSA Utilities' asset management plans. However, PB noted that ETSA Utilities' maintenance practices have, in the past, focussed on refurbishment of certain asset classes such as circuit breakers and transformers. Overall, PB considered that ETSA Utilities was able to demonstrate that it assesses refurbishment options in carrying out its maintenance and asset investment activities. However, PB considered that ETSA Utilities was unable to demonstrate the routine consideration of differences in expenditure in making its asset replacement decisions. Consequently, PB considered that ETSA Utilities analysis and selection of management strategies for individual asset classes is not well supported by economic assessment and therefore does not result in efficient expenditure.[433]

PB considered that a condition based asset management approach is a prudent approach to managing an ageing asset base, however ETSA Utilities has not been able to demonstrate the efficiency of the proposed replacement program through its asset management documentation. On this basis, PB conducted a detailed review of proposed asset replacement capex to ascertain if it aligns with prudent and efficient asset management practices.[434]

Review of asset replacement program

PB stated that ETSA Utilities proposed a significant increase in asset replacement capex due to its change in asset management approach to incorporate a greater degree of condition monitoring. PB was concerned that ETSA Utilities revised approach also includes a large degree of age based asset replacement forecasts that are not supported by the known condition of the assets and subsequently does not represent efficient expenditure.[435]

PB stated that asset age is a good long term asset replacement planning metric and is typically applied as an upper estimate for asset replacement over a 20 to 30 year horizon. However, it considered over the shorter term, asset population statistics and/or asset condition information should be used to ensure efficient timing of replacement capex forecasts. PB stated that as ETSA Utilities has condition

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[432] PB, *Report – ETSA Utilities*, October 2009, pp. 45–46.
[433] PB, *Report – ETSA Utilities*, October 2009, pp. 47–48.
[434] PB, *Report – ETSA Utilities*, October 2009, p. 44.
[435] PB, *Report – ETSA Utilities*, October 2009, p. 48.

information and failure rate data available, that data should be used as far as practicable to establish the efficient level of asset replacement in the next regulatory control period.[436]

PB noted that in order to optimise asset management, individual assets should be replaced or refurbished only when condition indicates imminent failure or when economically justified.[437] ETSA Utilities historical system average interruption duration index (SAIDI) performance for the period 2001 to 2009 indicates that the past management of its risks has been relatively successful.[438] PB considered that given ETSA Utilities consistent historical reliability performance and comparatively lower capex compared to its peers, the efficiency of any change in approach should be demonstrated.[439]

PB conducted a detailed review of ETSA Utilities asset replacement capex to establish an efficient level of replacement capex that reflects a condition based rather than age based asset management approach.[440] It reviewed ETSA Utilities proposed asset replacement program on the basis of the known condition and historical failure rates of its assets. PB aimed to establish an efficient level of asset replacement capex that reflects a condition based rather than age based asset management approach.[441]

PB conducted detailed reviews of five asset replacement categories which account for $245m or 52 per cent of ETSA Utilities proposed asset replacement capex of $467m.[442]

Unplanned line replacement

With respect to unplanned line replacement, PB noted that ETSA Utilities adopted a top–down approach to forecasting despite the bottom–up cost estimating approach set out in the asset management plans. The top–down approach applied involved the application of compounding growth factors based on ETSA Utilities analysis of historical failure rates and expenditure. PB considered that the bottom–up assessment in the asset management plans is not well supported and a top–down approach is appropriate. However it considered ETSA Utilities derivation of historical trends and application of compounding growth factors into the future is unreasonable and unlikely to result in prudent and efficient forecasts.[443]

PB used unplanned pole replacements as an example. Based on ETSA Utilities' pole failure history, a linear trend was determined which resulted in a compounding annual failure growth rate of 12 per cent. Similarly, based on expenditure history, ETSA Utilities determined an expenditure growth rate of 8.5 per cent per annum. On the basis of these calculations, ETSA Utilities applied a compounding growth rate of 11 per cent to its 2009 forecast expenditure. ETSA Utilities then made an adjustment to curtail the expenditure growth arising from this methodology. A similar approach

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436 PB, *Report – ETSA Utilities*, October 2009, p. 52.
437 PB, *Report – ETSA Utilities,* October 2009, p. 51.
438 PB, *Report – ETSA Utilities,* October 2009, p. 49.
439 PB, *Report – ETSA Utilities,* October 2009, p. 51.
440 PB, *Report – ETSA Utilities*, October 2009, p. 44 and p. 53.
441 PB, *Report – ETSA Utilities,* October 2009, p. 53.
442 PB, *Report – ETSA Utilities,* October 2009, p. 54.
443 PB, *Report – ETSA Utilities,* October 2009, pp. 54–55.

was applied for each of the major components of forecast unplanned lines replacement capex and PB considered this approach was unreasonable.[444]

PB noted that the historical expenditure in the sub–categories within unplanned lines capex (cables, overhead line components, poles, reclosers and overhead switchgear) included a step change from 2006 to 2007 and a flattening out in 2008 and was not driven by a trend in any single sub–category. PB considered this expenditure could be used to develop a substitute forecast.[445]

PB considered ETSA Utilities top–down approach did not result in a reasonable estimate of future capex and recommended that an average of 2007 and 2008 unplanned line capex be used as the basis for the forecast, resulting in an adjustment of $26 million ($2009–10).[446] PB stated that the adjustments result in expenditure which is prudent and efficient.[447]

Substation circuit breakers

PB noted ETSA Utilities' circuit breaker asset management plan sets out the volume of planned replacements based on asset condition and makes allowance for unplanned replacements based on documented circuit breaker failure history.[448]

PB noted that ETSA Utilities favoured the repair of circuit breakers rather than replacement. Further, planned replacements to address known type and condition issues were staged over the next regulatory control period to manage the risk of non–repairable failure. PB considered that ETSA Utilities has an effective condition based circuit breaker replacement strategy in place which is both prudent and efficient. However it noted that within the forecast circuit breaker replacement program, a program to replace circuit breakers purely on the basis of age was also included.[449]

Given the presence of an effective condition based replacement program, PB recommended that 106 of the 173 circuit breaker replacement items (those based purely on age) be removed from forecast substation circuit breaker replacement capex resulting in an adjustment of $37 million ($2009–10).[450]

Power transformers

ETSA Utilities power transformer asset management plan sets out the volume of planned power transformer replacements based on known issues and makes allowances for unplanned replacements based on the documented failure history of the transformer population. PB noted that the power transformer asset management plan also outlines that the spares holding is well planned and presents a well considered spares strategy while also noting that the existing condition monitoring

444 PB, *Report – ETSA Utilities*, October 2009, pp. 55–58.
445 PB, *Report – ETSA Utilities*, October 2009, p. 57.
446 PB, *Report – ETSA Utilities*, October 2009, pp. 57 and 59.
447 PB, *Report – ETSA Utilities*, October 2009, p. 58.
448 PB, *Report – ETSA Utilities*, October 2009, p. 59.
449 PB, *Report – ETSA Utilities*, October 2009, p. 59.
450 PB, *Report – ETSA Utilities*, October 2009, p. 60.

approach has in the past accurately predicted transformer failures enabling an orderly replacement plan.[451]

Despite its proven strategy of power transformer condition monitoring, ETSA Utilities has proposed that approximately 57 per cent of its transformer replacement forecast for the period from 2010 to 2020 be on the basis of age related risk. PB stated that given ETSA Utilities' actual replacement decision will be based on condition rather than age, such a large scale age based replacement program is not supported and should be removed from the capex forecast costs.[452]

Further, PB considered that the number of replacements (planned and unplanned) is greater than that supported by ETSA Utilities' historical data.[453] PB noted that ETSA Utilities has proposed replacement of the Tyree E465 66/11kV transformer class due to a design weakness. It considered the justification for the replacement is based on an arbitrary adjustment to the expected transformer life alone and is not supported on the basis of asset condition or risk and is therefore not prudent or efficient. PB recommended removing the Tyree 465 class transformer replacements from the capex forecast.[454]

PB reviewed the unplanned power transformer replacements (66kV >20MVA and 66kV 5–20MVA). PB stated that the forecast replacements were not consistent with the historical replacement data provided by ETSA Utilities. It recommended a reduction to the unplanned transformer replacement forecast so that it was consistent with the historical average. PB recommended that two transformers be removed from the unplanned 66kV (>20MVA) transformer replacement forecast and one from the 66kV (5–20MVA) transformer replacement forecast.[455]

In total PB recommended that forecast power transformer replacement be adjusted by the amount of $18 million ($2009–10).

Poles

ETSA Utilities' proposed pole refurbishment/replacement program is based on a model of pole age and corrosion zones. While pole age is unknown it may be implied from manufacturing history and an assumed age based on failure profile for each corrosion zone.[456] PB noted that there is a significant cost benefit associated with refurbishment of poles rather than replacement and an efficient asset owner would aim to refurbish poles prior to reaching the point where replacement is necessary.[457] ETSA Utilities noted this benefit in its proposed management strategy for stobie poles.[458] PB tested ETSA Utilities' pole refurbishment/replacement model by obtaining defect information from pole inspections over the past five years and comparing them with its own calculations and found that ETSA Utilities' proposed 11687 pole treatments (that is, refurbishments or replacements) accords with PB's

451 PB, *Report – ETSA Utilities*, October 2009, p. 61.
452 PB, *Report – ETSA Utilities*, October 2009, p. 61.
453 PB, *Report – ETSA Utilities*, October 2009, p. 61.
454 PB, *Report – ETSA Utilities*, October 2009, p. 62.
455 PB, *Report – ETSA Utilities*, October 2009, pp. 61–62.
456 PB, *Report – ETSA Utilities*, October 2009, p. 63.
457 PB, *Report – ETSA Utilities*, October 2009, p. 64.
458 PB, *Report – ETSA Utilities*, October 2009, p. 64.

calculation based on a ‘refurbish within 10 years estimate’.[459] PB stated that ETSA Utilities’ increased focus on refurbishment is prudent and that the total volume of its pole failure forecasts is efficient.[460]

PB noted that as a result of adopting an approach that favours refurbishment rather than replacement, the number of replacements should decline. ETSA Utilities’ low and medium corrosion zone forecasts reflect this decline (for example, in the medium corrosion zone, replacements are forecast to fall from 39 per cent to 15 per cent). However, in high corrosion zones, ETSA Utilities has forecast replacements to increase from 32 per cent to 80 per cent.[461] PB stated that no justification for the increase was provided by ETSA Utilities and further, it considered that an improvement to the historical replacement rate should be expected. Therefore it recommended a reduction to the forecast replacement rate to at least 15 per cent which is consistent with the forecast reduction in the replacement rate in the medium corrosion zone. As a result, PB recommended an adjustment to pole replacement capex of $22 million ($2009–10).[462]

Conductors

PB noted that ETSA Utilities based its proposed conductor replacement capex predominantly on the basis of age where age is considered to be the ‘useful asset life’.[463] It stated that ‘useful asset life’ is generally used for depreciation calculations and, given that age based replacement models are sensitive to input age, ETSA Utilities’ approach is likely to overstate forecast conductor replacement.[464]

PB stated that ETSA Utilities’ replacement model and asset management plan (AMP) also make allowance for corrosion zones and conductor type. Further, the forecast allowance for age based replacement to occur over a relatively long period (13 to 15 years depending on the corrosion zone) smoothes the volatility associated with a purely age based approach.[465] PB compared the model’s predicted expenditure with that of ETSA Utilities’ historical expenditure and demonstrated that the model predicted total expenditure, from 2005–06 to 2008–09, approximately seven times that of historical expenditure.[466] It noted that by increasing average useful life by approximately eight years, the model predicted results in line with historical data.[467] PB considered that following the adjustments it made to ETSA Utilities’ model, it could be used as a proxy for the efficient level of forecast replacement conductor

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459 PB, *Report – ETSA Utilities*, October 2009, pp. 64–65. The ‘refurbish within 10 years’ estimate refers to refurbishing a pole within the 10–year period prior to the pole reaching the 50 per cent metal loss criterion.

460 PB, *Report – ETSA Utilities*, October 2009, p. 65.

461 PB stated that ETSA Utilities advised that prior to 2007, areas were not defined in corrosion zones. PB has assumed that the corrosion zone based defect data provided by ETSA Utilities for years prior to 2007 is based on ETSA Utilities best estimates.

462 PB, *Report – ETSA Utilities*, October 2009, pp. 65–67.

463 PB, *Report – ETSA Utilities*, October 2009, p. 67.

464 PB, *Report – ETSA Utilities*, October 2009, pp. 67–68.

465 PB, *Report – ETSA Utilities*, October 2009, p. 68.

466 PB, *Report – ETSA Utilities*, October 2009, pp. 68–69.

467 PB, *Report – ETSA Utilities*, October 2009, p. 68.

capex. On this basis, it recommended an adjustment to forecast conductor replacement capex of $18 million ($2009–10).[468]

General asset replacement adjustment

PB reviewed in detail proposed replacement capex totalling $245m ($2009–10), or 52 per cent of total replacement capex and recommended a reduction of approximately 49 per cent to $125 million. In its detailed review, it noted a reliance on age based forecasting as well as existing condition based forecasts. Further, it noted the use of compounding annual growth rates which are not supported by historical data, and the limited use of known condition data to be of concern. PB noted that ETSA Utilities has adopted a similar approach to estimating replacement capex across each of the asset replacement categories, which it considered was indicative of a systemic overestimation of replacement capex. On this basis, PB stated that the remainder of ETSA Utilities' forecast asset replacement capex is not representative of prudent and efficient expenditure.[469]

PB tested its view by conducting a high level review of the forecasts set out in the overhead line components asset management plan and the protection and control asset management plan. It found similar issues to those identified in its detailed review and therefore recommended that a general adjustment be applied to the remainder of ETSA Utilities' replacement capex. PB recommended that a pro rata reduction of 49 per cent be applied to the remaining 48 per cent of ETSA Utilities' asset replacement capex allowance.[470] Consequently PB recommended a general adjustment of $108 million ($2009–10).

PB recommended a total reduction to ETSA Utilities' replacement capex of $228 million ($2009–10). Following the application of the adjustment to replacement capex due to cost escalation, PB recommended a reduction of $242 million ($2009–10) to ETSA Utilities forecast replacement capex allowance for the next regulatory control period.[471]

AER considerations

The AER notes that ETSA Utilities' proposed replacement capex is forecast to increase approximately 200 per cent compared to the current regulatory control period. ETSA Utilities stated that much of its asset base is approaching the end of its prudent engineering life and that it has recently adopted an asset management policy and asset management strategies to promote condition based asset replacement.[472] However, ETSA Utilities was unable to demonstrate that its new asset management strategy, at least as currently applied, was least cost or highest NPV (and therefore more efficient) compared to its current replace on failure approach. The AER notes that much of ETSA Utilities' forecast replacement capex program relied on age based forecasting in addition to ETSA Utilities' existing condition based forecasts.[473] The AER considers a condition based asset replacement approach which factors in many

[468] PB, *Report – ETSA Utilities,* October 2009, pp. 69–70.
[469] PB, *Report – ETSA Utilities,* October 2009, pp. 70–71.
[470] PB, *Report – ETSA Utilities*, October 2009, p. 71.
[471] PB, *Report – ETSA Utilities,* October 2009, pp. 72 and 92.
[472] ETSA Utilities, *Regulatory proposal,* July 2009, p. 119.
[473] PB, *Report – ETSA Utilities,* October 2009, p. 70.

asset variables (such as, age, defect history and physical conditions) is prudent and will likely point towards an efficient outcome. The AER considers an asset replacement approach which is based on condition as well as age is not prudent or efficient. Given ETSA Utilities has forecast replacement based on condition and age, the AER considers adjustments to replacement capex are warranted.

The AER has reviewed the documentation provided by ETSA Utilities in support of its forecast replacement capex allowance and considered the advice provided by PB. PB recommended adjustments to every replacement capex category it reviewed based on a lack of prudence and/or inefficiency (or a lack of demonstrated efficiency). Based on PB's analysis and recommendations, the AER considers several adjustments to ETSA Utilities replacement capex are necessary to reasonably reflect the capex criteria, including the capex objectives.

In the unplanned lines asset replacement category, the AER notes PB's analysis which indicates that ETSA Utilities has rejected the bottom–up estimates set out in its asset management plans and substituted a top–down approach. During its review PB found that unplanned pole failures (a category of unplanned lines) forecast capex was based on compounding annual growth rates of historical expenditure and failure rates. Based on these two compounding growth rates, ETSA Utilities has effectively assumed an annual compounding growth rate of 11 per cent and applied this rate to its 2009 forecast capex figures for unplanned pole replacements (with a minor adjustment to curtail capex growth).[474] PB stated that ETSA Utilities has applied the same approach to each of its unplanned line replacement categories.[475] The AER accepts PB's advice that ETSA Utilities has applied unreasonable compounding growth rates which overstate forecast capex. The AER considers PB's proposed approach which takes the average of the 2007 and 2008 expenditure as the basis for the forecast to be a reasonable approach to forecasting capex for this category of asset replacement. Using this approach reflects the step change in 2007 which flattened out in 2008 and is consistent with recent business as usual expenditure (that is, the historical expenditure with abnormal under and over spends removed).

The AER notes PB's comments that ETSA Utilities has a circuit breaker population, some of which are 70 years of age and that the current condition and performance monitoring of circuit breaker assets is sufficient to manage the efficient replacement of its assets.[476] ETSA Utilities has an effective substation circuit breaker condition based replacement strategy in place and its provision for age based replacement of circuit breakers, in addition to its condition based approach is not prudent or efficient.[477] The AER considers that ETSA Utilities should remove the age based replacement of 106 circuit breakers from its forecast.

The AER notes PB's analysis that ETSA Utilities' substation power transformer replacement capex will be based on condition rather than age and therefore the inclusion of the age based replacements is unsupported. Additionally, PB has recommended an adjustment to the unplanned 66kV power transformer replacement

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474 PB, *Report – ETSA Utilities*, October 2009, pp. 55–56.
475 PB, *Report – ETSA Utilities*, October 2009, p. 57.
476 PB, *Report – ETSA Utilities*, October 2009, p. 59.
477 PB, *Report – ETSA Utilities*, October 2009, p. 60.

on the basis that the forecast replacement rate significantly deviates from the historical rate. Further, PB has recommended the removal of the Tyree E465 66/11kV transformer replacements from forecast capex on the basis of unknown condition and risk. While the age of an asset might be considered when assessing its condition the AER considers that it is inefficient for ETSA Utilities to base its power transformer replacement program on age as well as condition. ETSA Utilities has not provided sufficient information to justify the increases in unplanned 66kV power transformer replacements and the replacement of the Tyree E465 class transformers. The AER accepts PB's advice that the unplanned 66kV transformer replacements should be reduced by removing two transformers from the 66kV (20MVA) transformer class and one from the 66kV (5–20) transformer class. Additionally, the Tyree 465 class transformers should be removed from the forecast.

The AER notes PB's analysis which indicated that ETSA Utilities has an efficient strategy to refurbish poles before they need to be replaced. While PB considered that ETSA Utilities' strategy and forecast of pole failure was both prudent and efficient, it did not agree with the forecast pole replacement as a proportion of total failures for the high corrosion zone.[478] ETSA Utilities' pole defect history for the medium corrosion zone was 39 per cent and is forecast to decrease to 15 per cent. However, in the high corrosion zone, historical pole replacements were 32 per cent and are forecast to increase to 80 per cent. The AER notes that ETSA Utilities did not provide PB with justification for this increase and consequently, PB considered that the increase was not prudent and efficient. The AER accepts PB's advice that ETSA Utilities replacement rate should decrease to reflect efficiency improvements, not increase. The AER considers that a reduction from 80 per cent to 15 per cent for high corrosion zone replacements is prudent and efficient.

In considering conductor replacement capex PB noted the sensitivity of the ETSA Utilities model to asset age. PB used ETSA Utilities' model to predict historical conductor replacement in the period from 2005 to 2009 and found it overestimated actual replacement by four to ten times. PB adjusted the model's 'useful asset life' age by eight years until it aligned with the historical expenditure and recent defect history. PB stated that while ETSA Utilities' age based replacement approach was not in accordance with good asset management practices, in the absence of detailed conductor condition information, the (PB adjusted) model could be used as a proxy for efficient expenditure.[479] The AER considers that the approach recommended by PB is more likely to result in a prudent and efficient outcome as the use of historical data is more likely to reflect actual replacement timing.

The AER notes that PB's detailed review encapsulated 52 per cent of ETSA Utilities $467 million capex program and within every replacement category it reviewed, PB did not agree with the forecasts and accordingly recommended adjustments be made. PB noted that during the review, it found a reliance on age based forecasting in addition to existing condition based forecasts. Additionally it noted the use of compounding growth rates were not supported by the underlying historical data and limited use of known condition data. The AER is concerned that while PB has been able to identify these issues and recommend adjustments to 52 per cent of forecast

[478] PB, *Report – ETSA Utilities*, October 2009, p. 65.
[479] PB, *Report – ETSA Utilities*, October 2009, p. 69.

replacement capex, 48 per cent of replacement capex remains as forecast by ETSA Utilities. The AER considers that given the level of adjustment required to the categories subject to the detailed review, a general adjustment to the remaining replacement capex is, under the circumstances, justified. Considering the level of adjustment necessary to the 52 per cent of replacement capex reviewed by PB, the AER considers a proportionate adjustment based on the total adjustment derived from the detailed review is prudent.

The AER considers its decision regarding the efficiency of ETSA Utilities' proposed replacement capex will allay some of the concerns of Business SA, Origin and ECCSA. In response to ECCSA's concerns that ETSA Utilities may replace assets before the end of their useful lives, the AER is not in a position to tell DNSPs specifically when they can and can not replace assets. In accordance with the capex criteria in the NER, the AER must be satisfied that ETSA Utilities' total forecast capex reasonably reflects the efficient costs of achieving the capex objectives and the costs that a prudent operator would require to achieve the capex objectives. The AER considers that the analysis and adjustments to ETSA Utilities' replacement capex contribute to the achievement of its responsibilities under the NER.

The AER requested ETSA Utilities model the impact of its decision on replacement capex. ETSA Utilities advised that the adjustment to forecast replacement capex is a reduction of $227 million ($2009–10).

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast replacement capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities proposed replacement capex by $227 million ($2009–10) 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.

7.8.4.3 Security of supply capex

ETSA Utilities regulatory proposal

ETSA Utilities forecast an amount of $170 million ($2009–10) for security of supply capex during the next regulatory control period. Security of supply capex is a new expenditure category and there is no past expenditure to compare it against. Forecast security of supply capex represents approximately 6 per cent of ETSA Utilities' total forecast capex program. Table 7.9 sets out the proposed security of supply capex for each year of the next regulatory control period.

Table 7.9: ETSA Utilities forecast security of supply capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Security of supply	15.5	45.9	65.3	33.8	9.9	170.4

Source: ETSA Utilities, *Regulatory proposal,* July 2009, p. 122.

Kangaroo Island network security

ETSA Utilities proposed capex of $95 million in the next regulatory control period to improve Kangaroo Island's network security.[480] ETSA Utilities proposed to install a second undersea cable to mitigate the risk of catastrophic failure of the existing undersea cable. During the current regulatory control period ETSA Utilities installed diesel generation with a capacity of 6 MW as a backup supply to Kangaroo Island. Due to plant maintenance requirements, the backup supply would only be available to supply Kangaroo Island for a period of 10 to 14 days and fuel costs over an extended period would be high.[481]

ETSA Utilities proposed to replicate the existing 33kV backbone on Kangaroo Island with a 66kV backbone to remove a constraint on development. ETSA Utilities stated that economic development is currently being constrained because large customers and developers are unwilling to make the significant capital contributions required to allow them to connect to the network. Additionally, analysis undertaken by the Kangaroo Island Regional Development Committee indicated that there is considerable unserved peak demand which is supplied by local generation rather than the distribution network.[482]

Network control

ETSA Utilities proposed capex of $10 million per annum to replace or upgrade network control systems, including:[483]

- replace its SCADA software due to technical obsolescence
- build a larger network operations centre to accommodate the increase in resources to support additional field work
- manage the risk of evacuating its main network operations centre by building a backup operations centre
- install additional switches at high bushfire risk boundaries to provide for more precise disconnection and reconnection of feeders during high bushfire risk conditions.[484]

Substation land

ETSA Utilities proposed capex of $5.2 million per annum for the acquisition of land for substation development as part of its capex program.[485]

Consultant review

PB conducted a detailed review of the Kangaroo Island and network control security of supply projects.

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480 ETSA Utilities, *Regulatory proposal*, July 2009, p. 122.
481 ETSA Utilities, *Regulatory proposal*, July 2009, p. 123.
482 ETSA Utilities, *Regulatory proposal*, July 2009, p. 123.
483 ETSA Utilities, *Regulatory proposal*, July 2009, p. 124.
484 ETSA Utilities has a policy of disconnecting high bushfire risk areas under certain circumstances to mitigate the risk of bushfire.
485 ETSA Utilities, *Regulatory proposal*, July 2009, p. 124.

Kangaroo Island network security

In reviewing the Kangaroo Island network security project PB noted several concerns:[486]

- As ETSA Utilities is not obliged to meet an N–1 criterion for Kangaroo Island, duplication of the undersea cable is not necessary to meet ETSA Utilities planning obligations for the next regulatory control period.

- ESCOSA noted that it expects ETSA Utilities to meet the 450 SAIDI target using existing generation and ETSA Utilities reported 2008 calendar year performance of 261 SAIDI minutes.

- The 450 minute SAIDI target was intended to have the same effect as an N–1 criterion.

- The planned $3.6m augmentation of Kangaroo Island's Kingscote Power station generation plant is intended to meet the islands' peak demand.

- Based on ETSA Utilities' documentation, the capacity driven undersea cable augmentation is not required until 2016 and the capacity driven 66kV sub–transmission augmentation is not required until 2025.

PB noted that in addition to the Kingscote power station, there is significant private generation available to meet Kangaroo Island's peak demand and therefore the risk of failure of the existing undersea cable is well mitigated.[487]

ETSA Utilities put forward four options for the long–term development of Kangaroo Island, two were developed on the basis of 7 per cent annual load growth rate while the others were based on historical growth of 3.3 per cent. PB considered the options based on historical growth only as it considered that providing capacity for speculative load growth went beyond ETSA Utilities planning obligations. The options include:[488]

- a capacity driven scenario where the undersea cable is required in 2016 and the sub–transmission augmentation required in 2025

- a security of supply driven scenario whereby the cable is installed in 2012 and the sub–transmission augmentation required in 2014.

PB noted that ETSA Utilities has estimated the long–term emergency supply costs for Kangaroo Island would be $20.7 million ($2008) for a 12 month period. However ETSA Utilities did not include these costs into the options it considered and PB considered they should be included in any assessment of the option costs.[489]

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486 PB, *Report – ETSA Utilities*, October 2009, p. 79.
487 PB, *Report – ETSA Utilities*, October 2009, pp. 79–80.
488 PB, *Report – ETSA Utilities*, October 2009, p. 80.
489 PB, *Report – ETSA Utilities*, October 2009, p. 80.

PB conducted an NPV analysis on the capacity and supply driven scenarios and included the probability weighted cost of emergency supply into its calculations. Regardless of the discount rate applied, the capacity driven scenario was the highest NPV option over 30 years.[490]

PB stated that ETSA Utilities is not in breach of its mandatory security of supply requirements under the current arrangements and its proposed security of supply option is not the least cost option to meet the capacity requirements of Kangaroo Island. On this basis, PB recommended that the Kangaroo Island cable duplication project and the 66kV sub–transmission augmentation project be removed from the forecast capex allowance for the next regulatory control period.[491]

Network control

PB noted that ETSA Utilities' proposed network control project is based on portions of the scope set out in a report by KEMA on ETSA Utilities' SCADA and distribution management system (DMS).[492] Following its review of the project, PB was concerned with a number of aspects.[493]

KEMA set out the staffing requirements to deliver the program over the next regulatory control period. PB stated that the majority of staff resourcing relates to engineering and operational staff. PB noted that in response to its enquiries, ETSA Utilities identified that staff costs associated with the network operations centre (NOC) should be allocated to forecast opex only. On this basis, PB recommended reducing the labour component of the network control projects by 80 per cent, a reduction of $7.9 million ($2009–10).[494]

PB considered IT capex for the establishment of a disaster recovery site. The disaster recovery site will be used while a new NOC is built and the existing NOC is converted to a disaster recovery site. PB considered that while the establishment of a disaster recovery site is prudent and efficient, ETSA Utilities has included IT capex which will have a limited life of two to three years.[495] PB noted that up to now ETSA Utilities has accepted the risk associated with not having a SCADA equipped disaster recovery centre and it considered the additional IT capex for a temporary disaster recovery site to be inefficient.[496] It recommended a reduction of $3.3 million ($2009–10).[497]

KEMA included land acquisition costs as part of the costs associated with building the new NOC. PB noted that the new NOC will be developed on a site owned by ETSA Utilities and recommended a reduction of $0.2 million ($2009–10).[498]

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490 PB, *Report – ETSA Utilities*, October 2009, pp. 81–82.
491 PB, *Report – ETSA Utilities*, October 2009, p. 82.
492 KEMA is an energy consulting and testing and certification company.
493 PB, *Report – ETSA Utilities*, October 2009, p. 83.
494 PB, *Report – ETSA Utilities*, October 2009, p. 84.
495 PB, *Report – ETSA Utilities*, October 2009, p. 84.
496 PB, *Report – ETSA Utilities*, October 2009, p. 85.
497 PB, *Report – ETSA Utilities*, October 2009, p. 86.
498 PB, *Report – ETSA Utilities*, October 2009, pp. 85–86.

PB recommended a total reduction to the forecast network control capex component of security of supply capex of $11 million ($2009–10) or 23 per cent.[499]

Substation land

PB noted that ETSA Utilities increase in substation land acquisition capex is consistent with the increase in capacity expenditure associated with new lines and substation sites. Based on its high level review, PB did not consider a more detailed review was required and recommended that ETSA Utilities proposed substation land capex be accepted.[500]

AER considerations

Kangaroo Island network security

The Kangaroo Island undersea cable duplication and 66kV backbone upgrade accounts for $95 million ($2009–10) or approximately 55 per cent of total forecast security of supply capex. In considering the Kangaroo Island project, the AER has taken into account the outcome of PB's detailed review and those of ESCOSA in its electricity distribution service standards final decision for 2010–2015.[501] ESCOSA stated that it had set ETSA Utilities' SAIDI target for Kangaroo Island at 450 minutes in July 2004 as it considered that it would have the same effect as a separate N–1 reliability standard for supply to the island. Further it considered it would likely bring forward a solution to address both the possibility of failure of the undersea cable as well as the ongoing reliability problems on the island.[502] ESCOSA noted that in 2006 ETSA Utilities installed backup generation on Kangaroo Island.

The AER notes that ETSA Utilities will add a fourth generator to the three existing generators at the Kingscote power station during the next regulatory control period. ETSA Utilities stated that following the commissioning of this additional generator it will be able to supply the island's entire load 95 per cent of the time.[503] The AER also notes the availability of private generation on the island which, as set out in the Wessex Consult investigation, could supply approximately 99 per cent of the island's peak demand.[504] Given the standby generation available at the Kingscote power station and the availability of private generation, the AER accepts PB's advice that the risks associated with failure of the undersea cable are well mitigated.

The AER also notes PB's work to establish the NPV of the two options, based on historical growth rates, for the long–term development of the Kangaroo Island network. Based on PB's analysis discussed above, replacement of the undersea cable in 2016 and augmenting the 66kV sub–transmission network in 2025 is the least cost

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499 PB, *Report – ETSA Utilities*, October 2009, p. 86.

500 PB, *Report – ETSA Utilities*, October 2009, p. 78.

501 ESCOSA, *South Australian electricity distribution service standards: 2010–2015, Final decision*, November 2008.

502 ESCOSA, *South Australian electricity distribution service standards: 2010–2015, Final decision*, November 2008, p. 62.

503 ETSA Utilities, email to the AER, 31 July 2009, p. 5.

504 Wessex Consult Pty Ltd, *An investigation into the utilisation of end user generation on Kangaroo Island*, January 2009, p. 15. The AER is not suggesting that private generation be used to supply to supply to entire Island in the event of an outage, rather the Wessex report highlights the level of private generation available on Kangaroo Island.

option and the AER supports an efficient least cost option for the Kangaroo Island network control project.

The South Australian Energy Minister supported maintaining security and reliability of supply on Kangaroo Island and supported further development in the region. The AER notes that the commissioning of a fourth generator at the Kingscote power station will assist in maintaining security and reliability. Additionally, based on PB’s analysis, the installation of a second undersea cable prior to 2016 and the augmentation of the sub–transmission network in 2025 would not be the least cost solution. The AER considers that consistent with the capex criteria in the NER to promote efficient investment, delaying the Kangaroo Island project is prudent.

The AER has concluded that the risks associated with the failure of the undersea cable are well mitigated by ETSA Utilities’ standby generation at Kingscote power station and private generation. Further, based on PB’s NPV analysis, replacing the undersea cable in 2016 and augmenting the 66kV sub–transmission network in 2025 results in the least cost outcome. On this basis, the AER considers the removal of the Kangaroo Island project from the forecast security of supply capex is both prudent and efficient.

Network control

PB reviewed ETSA Utilities’ proposed network control project which accounts for a total of $50 million ($2009–10) or 29 per cent of the total security of supply expenditure for the next regulatory control period.

The AER notes PB’s finding that the bulk of labour resourcing requirements for the NOC have been included in the capex and opex forecasts. The double counting associated with the engineering and operational staff should be removed from the capex forecast for the next regulatory control period. Additionally, the IT capex proposed for use over a period of just two to three years is inefficient and should be removed from the forecast. The forecast capex for land acquisition costs associated with the NOC should also be removed as the new NOC will be built on land already owned by ETSA Utilities.

Substation land

ETSA Utilities has included an allowance for proactive purchase of substation land for its capital program. The proposed expenditure is based on unit costs per area of land and is based on Valuer General valuations. Proposed land acquisition capex is forecast to average $5 million per annum. PB’s high level review indicated that the increase in substation land is consistent with the increase in ETSA Utilities’ capex program.

The AER notes that PB’s high level capex review included a review of ETSA Utilities’ capital governance and policies and procedures. The AER considers that ETSA Utilities’ proactive purchase of substation land to be prudent and given that substation land forecast capex is less than one per cent of forecast total capex has not conducted a detailed review. Therefore the AER is satisfied the costs are consistent with the requirements of the NER and no adjustments have been made to forecast substation land capex.

Adjustment to security of supply capex

The AER requested ETSA Utilities model the impact of the AER's decision on security of supply capex. ETSA Utilities advised that the adjustment to forecast security of supply capex is a reduction of $105 million ($2009–10).

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast security of supply capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities proposed security of supply capex by $105 million ($2009–10) 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.

7.8.4.4 Reliability capex

ETSA Utilities regulatory proposal

ETSA Utilities forecast an amount of $25 million ($2009–10) for reliability capex during the next regulatory control period, an increase of 44 per cent (in real terms) compared to the current regulatory control period. Forecast reliability capex represents approximately 1 per cent of ETSA Utilities' total forecast capex program. Table 7.10 sets out the proposed reliability capex for each year of the next regulatory control period.

Table 7.10: ETSA Utilities proposed reliability capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Reliability	4.9	5.0	5.0	5.1	5.2	25.2

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 126.

ETSA Utilities stated that its reliability capex is required to maintain its reliability performance in accordance with ESCOSA's service standards targets.[505] Reliability capex is generally targeted to increase operational flexibility of the network during outages by providing additional information or by providing additional restoration points.[506] Additionally, capex on emergency response equipment such as generators and plant to maintain supply to customers during planned maintenance is captured within reliability capex.[507]

The key driver for the increase in reliability capex is related to additional and replacement investment in emergency response equipment.[508]

Consultant review

PB noted that proposed reliability capex is driven by a need to maintain current network reliability levels and is therefore driven by compliance issues.[509] It stated that

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505 ETSA Utilities, *Regulatory proposal*, July 2009, p. 126.
506 ETSA Utilities, *Regulatory proposal*, July 2009, p. 126.
507 ETSA Utilities, *Regulatory proposal*, July 2009, p. 126.
508 ETSA Utilities, *Regulatory proposal*, July 2009, p. 127.

the proposed increase is largely consistent with total historical expenditure.[510] Based on its high level review, PB concluded that the proposed expenditure is prudent and efficient and did not consider a more detailed review was required.[511] It recommended that ETSA Utilities reliability capex be accepted.[512]

AER considerations

ETSA Utilities' reliability capex is forecast to increase from 2008–09 expenditure of $3.9 million to an average of $5 million per year in the next regulatory control period. The AER notes that ETSA Utilities is required to meet ESCOSA's service standard targets.[513] The South Australian Electricity Industry Code (EIC) specifies that ETSA Utilities must use its best endeavours to meet its average service standards targets and compliance with the EIC (and hence the jurisdictional average service standards) is a licence condition for ETSA Utilities.[514]

The AER notes ETSA Utilities claims regarding the increased operational flexibility arising from reliability capex, and that the variance over the current regulatory control period relates to additional and replacement expenditure for emergency response plant.

ESCOSA noted that in the period from 2005 to 2007, ETSA Utilities' reliability performance was below its targets in the majority of regions but in 2007–08, its performance improved significantly.[515] ETSA Utilities total network SAIDI target was 165 minutes, and its performance in 2005–06 and 2006–07 was 199 minutes and 184 minutes respectively.[516] In 2007–08 performance was under the target at 150 minutes. Despite this improvement, ESCOSA remained concerned with ETSA Utilities' performance in a number of regional supply areas particularly with respect to outage duration.[517] Targeted reliability capex will assist in addressing this issue.

The AER notes the concerns of interested parties in submissions on ETSA Utilities' forecast reliability capex. COTA stated that South Australian consumers are happy with current reliability levels and are unwilling to pay for greater reliability. The AER notes that ETSA Utilities' reliability capex is largely stable when compared to the current regulatory control period and much of the increase relates to expenditure on emergency response equipment to manage both planned and unplanned outages on its

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509 PB, *Report – ETSA Utilities*, October 2009, pp. 21 and 42.
510 PB, *Report – ETSA Utilities*, October 2009, p. 42.
511 PB, *Report – ETSA Utilities*, October 2009, pp. xiv, 21, 42 and 92.
512 PB, *Report – ETSA Utilities*, October 2009, p. 92.
513 ESCOSA's role in service standards is to set average service standards and a guaranteed service level payments scheme. The AER will apply and monitor a service standards incentive scheme to ETSA Utilities for the next regulatory control period.
514 ESCOSA, *South Australian electricity distribution service standards: 2010–2015, Final decision*, November 2008, p. 22.
515 ESCOSA, *South Australian electricity distribution service standards: 2010–2015, Final decision*, November 2008, p. 24.
516 ESCOSA, *South Australian electricity distribution service standards: 2010–2015, Final decision*, November 2008, p. 25. ESCOSA noted there is no explicit SAIDI target for the total network and the target figure quoted is taken from part A of the Electricity Distribution Price Determination and reflect average performance of the total network for 2000–01 to 2003–04.
517 ESCOSA, *South Australian electricity distribution service standards: 2010–2015, Final decision*, November 2008, p. 24.

network. In response to the ECCSA's concerns, the AER notes that ETSA Utilities' compliance with its jurisdictional service standards is a licence condition and therefore not optional. Business SA considered that lowest priority should be given to reliability capex where supply is reliable and stable. The AER agrees with this aspect of Business SA's submission and notes that ETSA Utilities targets its reliability capex where network reliability is worst.

The AER notes that ETSA Utilities must comply with jurisdictional service standards obligations and the forecast reliability capex is largely in line with historical expenditure. Further, the proposed expenditure on plant, to manage planned and unplanned outages, is likely to enhance network reliability and further assist it in meeting jurisdictional service standards. The AER is satisfied ETSA Utilities' proposed reliability capex is prudent and reflects efficient costs.

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and other material, the AER is satisfied that ETSA Utilities' 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.

7.8.4.5 Safety

ETSA Utilities regulatory proposal

ETSA Utilities stated safety capex is associated with maintaining safety of the network for its workforce and the general public. ETSA Utilities forecast an amount of $131 million ($2009–10) for safety capex during the next regulatory control period, an increase of 589 per cent (in real terms) compared to the current regulatory control period. Forecast safety capex represents approximately 5 per cent of ETSA Utilities' total forecast capex program. Table 7.11 sets out the proposed safety capex for each year of the next regulatory control period.

Table 7.11: ETSA Utilities proposed safety capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Safety	18.4	24.6	27.9	29.9	30.2	131.0

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 128.

ETSA Utilities' safety related asset management plans include long term (10 to 20 year) replacement programs which have been in place for some time. Based on advice from SKM and Maunsell, safety risks related to some network elements have been reassessed resulting in acceleration of some programs and implementation of additional programs.[518]

ETSA Utilities existing safety programs vary in scope and include replacement of high risk assets, upgrading assets that do not comply with occupational health and

[518] ETSA Utilities, *Regulatory proposal*, July 2009, p. 128.

safety requirements, removal of equipment containing asbestos and replacement of inoperable switchgear.[519] Further, its new programs include addressing:[520]

- occupational health and safety non–compliance risks in the CBD
- risks to the public and ETSA Utilities' employees at a number of substations
- replacement of the mobile radio system used to communicate in rural remote regions for network switching and emergencies.

ETSA Utilities engaged Maunsell to review its safety asset management plans. ETSA Utilities stated that Maunsell concluded that the key assumptions and methodology used to derive replacement numbers were generally valid and logical and the plans were consistent with industry practice.[521]

Maunsell was commissioned to develop a CBD asset management plan. It noted that repair and maintenance of CBD assets at night increased safety risks and costs to ETSA Utilities and its customers.[522] On this basis, ETSA Utilities proposed a significant asset replacement program for high risk CBD assets.[523]

Consultant review

PB reviewed two projects in detail which accounted for 55 per cent of forecast safety capex.

Substation security and fencing program

PB noted that ETSA Utilities' current substation fencing standard complies with mandatory requirements but it has proposed to apply a higher standard to substations that have been assessed as high risk in order to prevent unauthorised entry. Given ETSA Utilities' statement that its fences meet or exceed the relevant Australian Standard, its proposal to replace 57 per cent of all its substation fences over 10 years is not supported by PB.[524]

PB noted that the ENA has developed and published a guideline for prevention of unauthorised access to electricity infrastructure. The ENA guideline is mainly intended for new installations and recommends a site–specific approach to security. PB noted that ETSA Utilities reviewed its existing substation fences in 2003 and more recently conducted a site risk assessment based on the ENA guidelines. PB reviewed this approach and found that it results in a high risk being assigned to sites deemed to be medium or low risk. PB concluded that ETSA Utilities analysis was inconsistent with the ENA guideline as well as ETSA Utilities risk management framework.[525]

PB noted that ETSA Utilities proposed safety capex also includes provision for 30 closed circuit television (CCTV) installations and supporting research and

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519 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 128–129.
520 ETSA Utilities, *Regulatory proposal*, July 2009, p. 129.
521 ETSA Utilities, *Regulatory proposal*, July 2009, p. 129.
522 ETSA Utilities, *Asset management plan*, AMP 2.1.07, 2009 to 2020, CBD, February 2009, p. 5.
523 ETSA Utilities, *Regulatory proposal*, July 2009, p. 129.
524 PB, *Report – ETSA Utilities*, October 2009, pp. 72–73.
525 PB, *Report – ETSA Utilities*, October 2009, p. 73.

development for other security improvement measures. PB noted that ETSA Utilities has commenced trials at two sites and the effectiveness and practicalities of the CCTV program have not been evaluated. Given the uncertainty surrounding the effectiveness of the trials PB did not consider a wide scale rollout is prudent.[526]

PB concluded that a targeted approach to improving substation security at high risk sites where a site specific need is identified may be warranted. It considered a proposal to improve security should be supported by a uniformly applied site specific risk assessment and where an approach is driven by security policy, a sound business case should be developed. PB stated that these requirements have not been demonstrated by ETSA Utilities.[527]

PB stated that while ETSA Utilities' focus on substation security is prudent it has not demonstrated the efficiency of the scope of its proposed security fencing replacement program. PB recommended a condition based approach which essentially allows for:[528]

- installing high security fencing at substations assessed as high risk
- installing new chain wire fences to replace the existing fences at substations assessed as low and medium risk where the fence condition is assessed as a high risk
- upgrading existing chain wire fences at substations assessed as low and medium risk where the fence condition is assessed as a medium risk
- installing CCTV at demonstrated high-risk installations following targeted R&D to demonstrate the business case.

PB designed a substitute substation security and fencing replacement plan and based on its calculations, recommended a reduction of $14 million ($2009–10) to the total safety capex program.[529]

CBD aged asset replacement program

PB conducted a detailed review of ETSA Utilities' safety related CBD aged asset replacement program which targeted aged, obsolete and unsafe switchgear, cables and associated equipment in Adelaide's CBD. It noted the program included safety driven installation of ducts and manholes due to overcrowding and fault level control to facilitate improved access to cable vaults as well as replacements of:[530]

- low voltage switchboards
- 33kV switchgear that can not be operated because of safety bans
- cables.

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[526] PB, *Report – ETSA Utilities*, October 2009, p. 73.
[527] PB, *Report – ETSA Utilities*, October 2009, pp. 73–74.
[528] PB, *Report – ETSA Utilities*, October 2009, p. 74.
[529] PB, *Report – ETSA Utilities*, October 2009, pp. 75–76.
[530] PB, *Report – ETSA Utilities*, October 2009, p. 76.

PB stated that the only economic rationale provided for the proposed replacement was that the current approach (of conducting maintenance work at night) resulted in higher operational costs and reduced staff effectiveness. It stated that no attempt had been made to quantify the reduction in opex costs or determine the value of the risk reduction achieved as a result of completing the CBD replacement program. In meetings with PB, ETSA Utilities stated that detailed economic assessments had not been made for the project as the need was clear and asset risk is unacceptable in the long term. PB requested information on the project risk assessment and costing. ETSA Utilities stated that the risk posed with the current risk mitigation measures in place is medium and therefore the project is considered discretionary under its capital budgeting procedures.[531]

PB considered that, given the importance of the Adelaide CBD load it is prudent to address safety issues that restrict the ability of ETSA Utilities to operate the CBD network.[532] However, it considered that ETSA Utilities had not demonstrated the efficiency of its proposed solutions and, given the large number of individual projects, recommended a high level adjustment be made based on ETSA Utilities' historical risk level.[533]

ETSA Utilities prepared its regulatory proposal on the basis of addressing risks above a medium or 6.0 risk level. PB noted that ETSA Utilities applied micro–risk levels of 6.4 and 6.5 in its annual budgets for 2008 and 2009, however it has not applied these micro–risk levels in its regulatory proposal.[534] Further PB noted that the risk bands indicate the residual risk if ETSA Utilities were not to undertake the proposed works program in the year planned and deferral of projects would generally raise the risk level. PB considered that if the historically accepted risk level of 6.4 were applied to the CBD asset replacement projects, it would result in an annual deferral of 40 per cent of capex. PB calculated its adjustment to ETSA Utilities' CBD aged asset replacement program in this manner and recommended a reduction of $4.7 million ($2009–10).[535]

AER considerations

ETSA Utilities proposed safety related capex totalling $131 million and PB conducted a detailed review of the substation security and fencing and CBD aged asset replacement programs accounting for approximately 55 per cent of the expenditure.

The AER notes ETSA Utilities' existing fencing meets or exceeds the relevant Australian Standard and its practice of topping fences with three strands of barbed wire is consistent with other electricity companies in Australia and overseas.[536] Despite its fencing meeting the Australian standard and the widely accepted ENA guideline, ETSA Utilities proposed to adopt a more stringent standard for high security fencing for its substations. The AER notes that ETSA Utilities proposed to

531 PB, *Report – ETSA Utilities*, October 2009, pp. 76–77.
532 PB, *Report – ETSA Utilities*, October 2009, p. 77.
533 PB, *Report – ETSA Utilities*, October 2009, p. 77. PB noted that the risk posed by the current risk mitigation process was deemed by ETSA Utilities to be medium or a numerical rating of 6.0.
534 Micro–risk levels provide for the scaling of risk between risk levels.
535 PB, *Report – ETSA Utilities*, October 2009, p. 77.
536 ETSA Utilities, *Asset management plan* AMP.5.1.03 2009 to 2020 – Substation fences and security, 29 May 2008, pp. 8–9.

assign a high risk to fences at sites which are considered be low or medium risks. The AER accepts PB's advice that the efficiency of the proposed fencing program has not been demonstrated.

ETSA Utilities also included provision for 30 CCTV installations at its substations. PB's analysis indicated that the practicalities and effectiveness of the CCTV monitoring has not been evaluated and therefore a wide scale roll out is not prudent.[537] The AER has reviewed ETSA Utilities' regulatory proposal and PB's advice and considers the proposed CCTV trial at two sites should be completed and evaluated before a forecast capex allowance is provided.

The AER considers that while ETSA Utilities has demonstrated that its focus on substation security and fencing is prudent, it has not demonstrated the efficiency of the scope of its proposed programs. The AER considers that a condition based approach to substation security and fencing be applied and has therefore reduced the forecast capex for this category.

ETSA Utilities proposed a replacement program for aged assets in the Adelaide CBD totalling $52 million ($2009–10). In the absence of any analysis to quantify the potential reduction in opex or risk associated with the replacement program, the AER considers ETSA Utilities has not demonstrated the efficiency of it proposed CBD replacement capex.

The AER notes the support for the CBD aged asset replacement program in submissions from Business SA and the South Australian Energy Minister.[538] ETSA Utilities' CBD asset replacement program will target obsolete and unsafe switchgear, cables and associated equipment in the Adelaide CBD. To date, ETSA Utilities has managed the risks associated with these assets by applying safety bans on live switching and restricting access to manholes containing energised high voltage cables.[539] The AER recognises there are likely to be benefits arising from the program in terms of safer working conditions for those working on CBD assets, reduced operating expenses for ETSA Utilities and therefore benefits for South Australian consumers. However, the AER also notes the concerns of PB that ETSA Utilities was unable to demonstrate the efficiency of the costs associated with the program. Based on its review, the AER agrees there is a need for the program to proceed but is concerned about how the proposed capex program has been forecast and particularly its efficiency.

ETSA Utilities assessed the risks associated with the CBD replacement program as 6.0 on its risk scale but did not quantify the risk to a micro level as it has in the past when developing its annual budget.[540] PB considered that if the historically accepted 'micro–risk' level of 6.4 (rather than the actual risk level of 6.0) were applied to CBD replacement projects, it would result in an annual deferral of 40 per cent of capex.[541] The AER considers that this approach to estimating the overall reduction in CBD

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537 PB, *Report – ETSA Utilities*, October 2009, p. 73.

538 Business SA, *Submisson to the AER*, August 2009, p. 6; and SA Energy Minister, *Submission to the AER*, September 2009, p. 2.

539 PB, *Report – ETSA Utilities*, October 2009, p. 76.

540 PB, *Report – ETSA Utilities*, October 2009, p. 77.

541 PB, *Report – ETSA Utilities*, October 2009, p. 77.

replacement capex is reasonable given the large number of individual projects and therefore considers that an annual deferral of 40 per cent of CBD replacement capex should apply.

The AER requested ETSA Utilities model the impact of the AER's decision on safety related capex. ETSA Utilities advised that the adjustment to forecast safety related capex is a reduction of $19 million ($2009–10).

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast safety related capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities proposed safety related capex by $19 million ($2009–10) 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.

7.8.4.6 Environmental capex

ETSA Utilities regulatory proposal

Environmental capex is undertaken to ensure appropriate management of environmental risks and compliance with Environmental Protection Agency (EPA) requirements. ETSA Utilities forecast an amount of $16 million ($2009–10) for environmental capex during the next regulatory control period, an increase of 152 per cent (in real terms) compared to the current regulatory control period. Forecast environmental capex represents less than 1 per cent of ETSA Utilities' total forecast capex program. Table 7.12 sets out the proposed environmental capex for each year of the next regulatory control period.

Table 7.12: ETSA Utilities proposed environmental capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Environmental	2.7	3.2	3.3	3.3	3.4	15.9

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 130.

ETSA Utilities stated the key drivers for increased environmental capex in the next regulatory control period were an increase in the following programs:[542]

- substation firewalls to minimise the risk of substation fires spreading and noise abatement to meet EPA noise standards
- oil containment solutions for high risk distribution transformers.

Additionally, environmental capex is proposed for the following ongoing programs:[543]

542 ETSA Utilities, *Regulatory proposal*, July 2009, p. 130.
543 ETSA Utilities, *Regulatory proposal*, July 2009, p. 130.

- substation transformer oil containment
- testing for and phased removal of polychlorinated biphenyl (PCB) contaminated substation assets in accordance with the Australian National PCB Management Plan.

Consultant review

PB conducted a high level review of proposed environmental capex and noted it is driven by compliance issues such as increased need for oil containment, fire and noise treatment at high risk substation sites. Based on its high level review, PB noted that the proposed capex is largely consistent with historical expenditure and concluded that it was prudent and efficient.[544]

AER considerations

The AER notes that ETSA Utilities engaged Maunsell to review its asset management plans. Maunsell noted that ETSA Utilities' environmental asset management plans put in place a management plan to ensure continual compliance with the *Environmental Protection Act 1993* (EPA), the Environmental Protection (Water Quality) policy and the requirements of the EPA.[545]

The AER notes that ETSA Utilities is required to comply with various environmental requirements and therefore considers that ETSA Utilities' forecast environmental capex to manage its ongoing environmental obligations is prudent. Given the materiality of the proposed capex (less than one per cent of total capex) and that it builds on expenditure to maintain compliance with relevant legislation in the previous and current regulatory control periods, the AER considers ETSA Utilities environmental capex is reasonable. Further, the AER accepts PB's advice that the proposed capex is prudent and efficient.

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and other material, the AER is satisfied that ETSA Utilities' forecast environmental capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

7.8.4.7 Other network capex

ETSA Utilities forecast an amount of $44 million ($2009–10) for other network capex during the next regulatory control period, a decrease of 21 per cent (in real terms) compared to the current regulatory control period. Forecast other network capex represents approximately 2 per cent of ETSA Utilities' total forecast capex program. Table 7.13 sets out the proposed other network capex for each year of the next regulatory control period.

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[544] PB, *Report – ETSA Utilities*, October 2009, p. xiv, p. 21, p. 42 and 92.
[545] Maunsell, *Asset management plan review*, 26 November 2008, pp. 43 and 45, confidential.

Table 7.13: ETSA Utilities proposed other network capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Other network	8.4	8.6	8.7	8.9	9.0	43.6

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 131.

Other network capex is undertaken for:[546]

- Power Line Environment Committee (PLEC)—undergrounding selected sections of the network in accordance with legislative requirements. Forecast PLEC capex accounts for the majority of other network capex at $37 million ($2009–10) or 84 per cent

- easements—expenditure associated with obtaining powerline easements which accounts for $4.4 million ($2009–10) or 10 per cent of other network capex

- other—specialist tools and equipment associated with condition monitoring account for approximately $3 million ($2009–10) or 6 per cent of other network capex.

Consultant review

PB stated that proposed other network capex included expenditure for easement acquisition, undergrounding, distribution training centre equipment costs and ETSA Utilities condition monitoring strategy. It noted that the majority of proposed expenditure was for the PLEC works which was driven by statutory compliance.[547] Based on its high level review, PB did not consider a more detailed review was required, concluding that the proposed expenditure was prudent and efficient.[548]

AER considerations

The AER notes the main component of other network capex is expenditure allocated to undergrounding capex in accordance with legislative requirements associated with the PLEC. Undergrounding capex is forecast to remain consistent with that of the current regulatory control period.

The AER requested further information on the breakdown of the remaining other network capex. ETSA Utilities advised that other components of the program related to forecast capex for network training plant and asset condition monitoring equipment.[549] On the basis of the information provided by ETSA Utilities the AER considers the remaining other network capex is prudent.

The AER has reviewed the information provided by ETSA Utilities and the advice from PB and considers the proposed capex is prudent and efficient.

546 ETSA Utilities, *Regulatory proposal*, July 2009, p. 131; and ETSA Utilities, email to AER, 14 September 2009.
547 PB, *Report – ETSA Utilities*, October 2009, p. 21.
548 PB, *Report – ETSA Utilities*, October 2009, pp. xiv, 21, 42 and 92.
549 ETSA Utilities, email to the AER, 14 September 2009.

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and other material, the AER is satisfied that ETSA Utilities' 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.

7.8.4.8 Other capex

ETSA Utilities regulatory proposal

ETSA Utilities proposed other capex of $99 million ($2009–10) comprising expenditure on equity raising costs and the capital allocation of superannuation costs.[550] Other capex represents approximately 4 per cent of the total forecast capex program. Table 7.14 sets out ETSA Utilities' proposed other capex by expenditure category.

Table 7.14: ETSA Utilities' proposed other capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Equity raising costs	10.1	12.1	10.3	9.3	7.8	49.5
Superannuation costs	9.2	9.5	9.9	10.2	10.5	49.3
Total other capex	19.3	21.6	20.1	19.5	18.3	98.8

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.2.1.
Note: Totals may not add up due to rounding.

Equity raising costs

ETSA Utilities proposed equity raising costs of $50 million during the next regulatory control period. No specific allowance for equity raising costs was made for ETSA Utilities in the current regulatory control period. ETSA Utilities' proposed equity raising expenditure relates to costs associated with financing its proposed capex program.[551]

ETSA Utilities submitted that the proposed equity raising costs had been developed based on advice from the Competition Economists Group (CEG).[552] On the basis of CEG's advice, ETSA Utilities estimated direct equity raising costs of four per cent and indirect equity raising costs of three per cent of the amount of equity to be raised via an external seasoned equity offering (SEO). These costs, together with assumed dividend reinvestment plan costs of one per cent, the benchmark cash flow analysis based on values from the PTRM, and the amount of required equity, have been used by ETSA Utilities to determine the proposed equity raising capex.[553]

Superannuation costs

ETSA Utilities proposed capex for superannuation costs of $49 million during the next regulatory control period. The superannuation expenditure included in ETSA

550 ETSA Utilities, *Regulatory proposal*, July 2009, p. 139.
551 ETSA Utilities, *Regulatory proposal*, July 2009, p. 139.
552 CEG, *Debt and equity raising costs: A report for ETSA*, June 2009.
553 ETSA Utilities, *Regulatory proposal*, July 2009, p. 139.

Utilities' capex program relates to the capital allocation of the increase in superannuation contributions that ETSA Utilities is required to make to the Electricity Industry Superannuation Scheme (EISS) on behalf of its employees.[554]

ETSA Utilities submitted that the EISS is a separate legal entity that is independent of ETSA Utilities. The rate of employer contributions required to be paid by ETSA Utilities to ensure that the EISS is appropriately funded is set by the EISS actuary in conjunction with the EISS Board.[555]

The proposed level of superannuation capex has been determined by ETSA Utilities on the basis of the contribution rates approved by the EISS Board, and reflects ETSA Utilities' allocation of costs between standard control, negotiated and unregulated services as well as a split between capital and operating expenditure on the basis of the labour components of each category.[556]

ETSA Utilities' proposed opex for superannuation costs is discussed in chapter 8.

AER considerations

Superannuation costs

While ETSA Utilities proposed superannuation costs as part of both its opex and capex proposals, the AER has discussed the details of its consideration of all proposed superannuation costs in the opex chapter.

In summary, in the course of its review of proposed superannuation costs, the AER identified a CPI escalation modelling error in ETSA Utilities' proposal. The AER requested ETSA Utilities model the impact of the error on proposed superannuation capex. ETSA Utilities advised that the adjustment to forecast superannuation capex is a reduction of $1.8 million ($2009–10).[557]

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.[558] A DNSP should only be provided an allowance for equity raising costs where cheaper sources of funding—for example, retained earnings—are insufficient,

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554 ETSA Utilities, *Regulatory proposal*, July 2009, p. 140.
555 ETSA Utilities, *Regulatory proposal*, July 2009, p. 161.
556 ETSA Utilities, *Regulatory proposal*, July 2009, p. 161.
557 ETSA Utilities, email to AER, 16 October 2009.
558 AER, *Decision, Powerlink Queensland*, p. 100; AER, *Final Decision, SP AusNet*, January 2008, p. 144; and AER, *Final Decision, ElectraNet*, 11 April 2008, p. 88.

subject to the gearing ratio and other assumptions about financing decisions being consistent with regulatory benchmarks.

The AER's detailed analysis and considerations of ETSA Utilities' proposed equity raising costs are set out in appendix J.

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.[559] The AER notes the data presented by CEG 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.[560] The AER considers that the data for Australian utilities on equity raising types categorised by purpose remains the most relevant guide to the types of equity issued by the benchmark firm.

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 it 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 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

559 AER, *Final decision, NSW DNSPs*, 28 April 2009, pp. 194 (table 8.18) and 579–587.
560 AER, *Final decision, ACT DNSP*, April 2009, appendix H, p. 241.

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.[561]

The AER's conclusion on benchmark equity raising costs for ETSA Utilities over the next regulatory control period is set out in table 7.15.

Table 7.15: AER's conclusion on ETSA Utilities' benchmark equity raising cost ($m, nominal)

Cash flow analysis	AER draft decision (total)	Notes
Dividends	603.2	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	181.0	30% of dividends paid
Cost of dividend reinvestment plans	1.8	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	1725.2	This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment)
Debt component	701.4	Set to equal 60% of RAB increase (not capex)
Equity component	1023.8	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	756.3	Includes dividends reinvested
External equity requirement	267.5	Equal to equity component less retained cash flows
External equity raising cost	8.0	External equity requirement multiplied by benchmark direct cost (3%)
Total equity raising cost	9.8	Sum of dividend reinvestment plan cost and external equity raising cost
Total equity raising cost ($2009–10)	9.2	To be added to the RAB at the start of the next regulatory control period

ETSA Utilities proposed to include equity raising costs as part of its capex forecast—that is, to amortise the allowance.[562] This is consistent with the AER's approach for

561 AER, *Final decision, NSW DNSPs*, April 2009, p. 194.

treating benchmark equity raising costs. While ETSA Utilities has used the benchmark cash flow analysis (as determined by the AER in its April 2009 regulatory determinations) to model the equity raising cost allowance, some 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 assumption set out in chapter 9, and removing the impact of capital contributions on the amount of tax payable in the cash flow analysis.[563]

Further, in amortising the equity raising cost allowance for regulatory purposes, ETSA Utilities has adopted a standard asset life of 22.2 years, while for tax purposes a standard asset life of 18.9 years has been adopted. The AER reviewed ETSA Utilities' calculations and considers that adjustments are required to properly weight each standard asset life by the RAB. The AER considers that the period over which equity raising cost is to be amortised should reflect the weighted average standard lives of all assets in ETSA Utilities' RAB. Based on this approach, the AER determined a standard life of 47.8 years for amortising equity raising costs in the PTRM, consistent with the weighted average standard asset life for ETSA Utilities. This standard life should also be used for tax purposes.

For the reasons discussed and as a result of the AER's analysis of ETSA Utilities' regulatory proposal, the AER is not satisfied that ETSA Utilities' proposed equity raising cost allowance reasonably reflects the capex criteria, including the capex objectives. The AER considers the revised benchmark equity raising cost allowance associated with ETSA Utilities' forecast capex, as set out in table 7.16 represents the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capex objectives in the next regulatory control period 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.

7.8.4.9 Non–system capex

ETSA Utilities regulatory proposal

ETSA Utilities' proposed non–system capex of $364 million ($2009–10) includes expenditure on information technology, property, fleet, and plant and tools. Non–system capex represents approximately 13 per cent of the total forecast capex program. Table 7.16 sets out ETSA Utilities' proposed non–system capex by major categories.

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562 ETSA Utilities, *Regulatory proposal*, July 2009, p. 139.

563 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.

Table 7.16: ETSA Utilities' proposed non–system capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Information technology	28.8	25.2	22.0	27.9	45.7	149.7
Property	17.0	17.8	21.7	15.9	11.0	83.4
Fleet	14.2	8.7	19.7	25.9	24.7	93.2
Plant and tools	7.8	7.2	6.9	8.3	7.3	37.5
Total non–system capex	67.8	59.0	70.3	78.0	88.7	363.8

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN proforma 2.2.1.
Note: Totals may not add due to rounding.

ETSA Utilities' expenditure on non–system assets is forecast to increase by $180 million ($2009–10) or 98 per cent from the current regulatory control period. Proposed expenditure in the next regulatory control period is greater than expenditure in the current regulatory control period for all categories of non–system capex.[564]

Information technology

ETSA Utilities has proposed to spend $150 million on IT during the next regulatory control period, an increase of 109 per cent from the current regulatory control period. The proposed expenditure includes increased baseline costs required to support existing applications, as well as expenditure associated with the implementation of a number of new systems and applications. ETSA Utilities has identified the following factors as influencing the proposed increase in baseline IT capex:[565]

- increasing levels of new personnel in the organisation
- increased reliance on mobile computing
- an increasing number of operating sites to support
- an increase in the level of required software upgrades and equipment renewals
- some major systems requiring renewal, such as the current Full Retail Contestability (FRC) systems.

The new systems which ETSA Utilities proposed to introduce include enterprise wide data management and project management systems, mobility and associated IT governance systems, an asset management system and a business workflow system.[566]

Property

ETSA Utilities' proposed capex for non–system property, including office and depot accommodation, buildings and land, amounts to $83 million during the next

564 ETSA Utilities, RIN proforma 2.2.1
565 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 132–133.
566 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 132–133.

regulatory control period. This represents an increase of 194 per cent from the current regulatory control period. The key proposed expenditure includes:[567]

- alleviation of accommodation constraints through facility upgrades, additional depots and depot rebuilds
- depot relocations, including the construction of two replacement depots, due to end of lease and council pressures
- ramp up of long–term programs for asbestos removal and depot security fencing
- capex at depots more than fifty years old, based on an assessment of condition and expected life.

Fleet

ETSA Utilities proposed fleet expenditure of $93 million on in the next regulatory control period. This represents an increase of approximately 39 per cent from the current regulatory control period. The forecast fleet capex relates to the purchase, replacement or rebuild costs associated with ETSA Utilities' commercial and passenger vehicles. ETSA Utilities stated its rebuild and replacement work requirements are typically governed by legislative requirements or manufacturers' recommendations, while new fleet expenditure forecasts are based on projected employee numbers and historical ratios of personnel to vehicles.[568]

Plant and tools

ETSA Utilities proposed to spend $37 million on plant and tools in the next regulatory control period. This represents an increase of 119 per cent from the current regulatory control period. Forecast expenditure in this category is associated with the purchase of plant and tools, generally for field based personnel. ETSA Utilities has identified the key drivers of increased capex in this category as workforce growth, the need for new and replacement specialist tools in support of condition monitoring strategies, and the standardisation of plant and tools for the existing workforce.[569]

Consultant review

PB reviewed ETSA Utilities' proposed non–system capex for the next regulatory control period. Its review encompassed a high level analysis of trends in expenditures from the current and previous regulatory control periods, and a detailed review of the specific expenditure categories proposed by ETSA Utilities. The detailed review included consideration of relevant policies and procedures and other expenditure drivers.[570]

In summary, PB found ETSA Utilities' proposed non–system capex to be prudent and efficient and did not recommend any adjustments to the proposed expenditure on that

[567] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 205–206.
[568] ETSA Utilities, *Regulatory proposal*, July 2009, p. 137.
[569] ETSA Utilities, *Regulatory proposal*, July 2009, p. 138.
[570] PB, *Report – ETSA Utilities*, October 2009, p. 93.

basis.[571] PB's findings on each category of ETSA Utilities' proposed non–system capex are set out below.

Information technology

PB reviewed ETSA Utilities' proposed IT capex, and found that the proposed increase in expenditure in this category is driven mainly by an increase in uptake of IT systems by existing staff, growth in employee numbers in the next regulatory control period, and increasing capability driven by business need.[572]

PB noted that ETSA Utilities' IT capex is comprised of two components, being core systems and maintenance (classed as 'business as usual' expenditure) and new business driven initiatives. PB considered the proposed core systems and maintenance expenditure to be comparable with capex in the current regulatory control period when taking into account expected growth in usage of IT systems by existing staff and growth in overall employee numbers.[573]

PB reviewed the proposed new business driven initiatives, including the proposed replacement of ETSA Utilities' FRC systems which accounts for $32 million of the proposed expenditure. PB found that the replacement FRC systems are required due to discontinued vendor systems supporting the existing IT platform, and that ETSA Utilities' cost sharing with Citipower and Powercor is an efficient way to establish the replacement FRC systems.[574]

Overall, PB considered that ETSA Utilities' business driven initiatives align with corporate strategy and that the timing of the initiatives is aligned with business driven needs. PB found ETSA Utilities expenditure to be efficient, including where it had substantiated estimated costs through external parties. On the basis of its review, PB found ETSA Utilities' IT capex to be prudent and efficient and recommended that the proposed IT capex be accepted as proposed. This recommendation was qualified by PB in recommending that the expenditure relating to new business driven initiatives be approved for the next regulatory control period as one-off expenditure and should not be considered to be business as usual.[575]

Property

PB reviewed ETSA Utilities' proposed property capex for the next regulatory control period. ETSA Utilities' property capex proposal is based on its property strategy, which PB found details the proposed works required to replace, repair, repurpose and relocate on a site by site basis.[576]

PB noted that ETSA Utilities' cost estimation process used condition assessments as a basis for upgrades and repairs, and that new/replacement facility costs had been estimated on the basis of a template depot concept design scaled to meet capacity requirements.[577] Property costs were offset against revenue realised from the sale of

[571] PB, *Report – ETSA Utilities*, October 2009, p. 109
[572] PB, *Report – ETSA Utilities*, October 2009, p. 97.
[573] PB, *Report – ETSA Utilities*, October 2009, p. 98.
[574] PB, *Report – ETSA Utilities*, October 2009, p. 99.
[575] PB, *Report – ETSA Utilities*, October 2009, pp. 99–100.
[576] PB, *Report – ETSA Utilities*, October 2009, p. 104.
[577] PB, *Report – ETSA Utilities*, October 2009, p. 105.

surplus land.[578] PB found that the majority of the new, replacement and relocation projects are relatively evenly distributed across 2011–12 to 2014–15, corresponding with forecast employee growth.[579]

PB considered that ETSA Utilities demonstrated an appropriate staggering of projects to correspond with employee growth. Further, PB considered that ETSA Utilities demonstrated sufficient rigour in its cost estimation process for existing facilities based on condition assessments, and for new facilities based on its generic depot design template.[580]

On the basis of its review, PB found ETSA Utilities' property capex to be prudent and efficient and recommended that the proposed property capex be accepted as proposed.[581]

Fleet

PB reviewed ETSA Utilities' proposed fleet capex and found that the proposed increase in expenditure in this category is driven by workforce growth and a requirement for a significant portion of the heavy vehicle fleet to be replaced in the next regulatory control period.[582]

PB confirmed that ETSA Utilities' fleet replacement policy is driven by need, determined on the basis of age and kilometre based criteria depending on vehicle type, and verified ETSA Utilities' adherence to the policy. Forecast vehicle numbers for the next regulatory control period were found to correlate with forecast workforce growth.[583]

In the course of its review, PB found that ETSA Utilities sought a range of market quotes for fleet purchases, and had considered options including the relative costs of owning versus leasing light vehicles. On the basis of its review, PB found ETSA Utilities' fleet capex to be prudent and efficient and recommended that the proposed fleet capex be accepted as proposed.[584]

Plant and tools

PB undertook a high level review of ETSA Utilities' proposed expenditure on tools and equipment.[585] PB noted that the proposed expenditure is based on a business as usual approach, with increases in expenditure required to support workforce growth and a larger vehicle fleet.[586]

As part of its review, PB considered the processes and procedures used to determine projected tooling and equipment levels and found them likely to lead to expenditures

578 PB, *Report – ETSA Utilities*, October 2009, p. 104.
579 PB, *Report – ETSA Utilities*, October 2009, p. 106.
580 PB, *Report – ETSA Utilities*, October 2009, p. 106.
581 PB, *Report – ETSA Utilities*, October 2009, p. 106.
582 PB, *Report – ETSA Utilities*, October 2009, p. 107.
583 PB, *Report – ETSA Utilities*, October 2009, p. 108.
584 PB, *Report – ETSA Utilities*, October 2009, p. 108.
585 PB, *Report – ETSA Utilities*, October 2009, p. 102.
586 PB, *Report – ETSA Utilities*, October 2009, p. 101.

that are prudent and efficient.[587] PB recommended that the proposed capex for tools and equipment be accepted without adjustment.[588]

AER considerations

The AER reviewed ETSA Utilities' non–system capex proposal, taking into account additional information provided in support of the regulatory proposal and the advice of PB.

The AER notes ETSA Utilities' proposed non–system capex represents a significant increase of 98 per cent from the current regulatory control period. The AER does however also note the cyclical nature of certain elements of the non–system capex, such as costs associated with the replacement of IT systems and the timing of fleet replacement expenditures.[589]

The AER recognises that workforce growth is an important driver of non–system capex given the need to ensure employees are provided with appropriate facilities, vehicles, equipment and support systems to deliver work programs efficiently. In this regard, the AER notes that ETSA Utilities expects its workforce to grow by approximately 29 per cent from current levels by the end of the next regulatory control period.[590]

The AER notes PB's conclusion that ETSA Utilities' proposed non–system capex is prudent and efficient.[591] The AER considers the underlying scope and timing of ETSA Utilities' non–system capex proposal is appropriately supported by the documentation provided with ETSA Utilities' regulatory proposal. The plans, policies and procedures underpinning the non–system capex proposal, such as ETSA Utilities' property strategy and fleet replacement policy, appear to provide an appropriate basis for investment need such as asset condition or usage, and for estimated costs. The AER therefore considers ETSA Utilities' proposed non–system capex to be prudent and efficient.

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 satisfied that ETSA Utilities' proposed non–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.

7.8.5 Deliverability of the forecast capex program

This section examines the methods proposed by ETSA Utilities to deliver its proposed capex program within the next regulatory control period in the context of determining whether the AER is satisfied that ETSA Utilities' forecast capex reasonably reflects the capex criteria.

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587 PB, *Report – ETSA Utilities*, October 2009, p. 101.
588 PB, *Report – ETSA Utilities*, October 2009, p. 102.
589 PB, *Report – ETSA Utilities*, October 2009, pp. 97 and 110.
590 ETSA Utilities, *Regulatory proposal*, July 2009, p. 103.
591 PB, *Report – ETSA Utilities*, October 2009, pp. 109–110.

ETSA Utilities regulatory proposal

ETSA Utilities increased its recruitment of apprentices and engineering trainees in anticipation of the growth in work volume from 2009. Despite this, ETSA Utilities acknowledged that it will not be able to deliver its increased capital program without assistance from external contractors.[592]

ETSA Utilities has a number of strategies for delivering the proposed work program, including:[593]

- standardisation of design and documentation of sub-stations to assist outsourcing
- identification of other key projects for outsourcing
- increased number of employees in workload ‘supply’ roles such as design, procurement and project management
- strategic alliances between multiple external contractors and ETSA Utilities’ staff to achieve greater efficiencies than traditional forms of contracting.

In further support of its ability to deliver the proposed capex program, ETSA Utilities noted that it has had significant experience gearing up to deliver large programs and projects in the past and that other comparable DNSPs have recently achieved increases in expenditure similar to that proposed by ETSA Utilities.[594]

Consultant review

The AER engaged Energy and Management Services (EMS) to review the deliverability of ETSA Utilities’ proposed capex and opex programs. In doing so, EMS reviewed ETSA Utilities’:[595]

- workforce resources, including the field workforce required at the time of construction and the engineering expertise required in the years preceding construction
- actual preparedness in the form of project management, design, and materials and plant procurement.

EMS relied on ETSA Utilities’ regulatory proposal, information received during interviews with key personnel, a range of supplementary information documents provided following the site visit and a number of external references relating to labour availability.[596]

EMS concluded that ETSA Utilities’ engineering workforce has been built up with sufficient lead time to allow an adequate level of expertise, experience, training and

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592 ETSA Utilities, *Regulatory proposal*, July 2009, p. 141.
593 ETSA Utilities, *Regulatory proposal*, July 2009, p. 141.
594 ETSA Utilities, *Regulatory proposal*, July 2009, p. 141.
595 EMS, *Deliverability of capital expenditure program as proposed by ETSA Utilities for the 2010–2015 regulatory period*, September 2009, p. 2.
596 EMS, *Deliverability of capex program proposed by ETSA Utilities*, September 2009, p. 2.

development and that the range and diversity of engineering disciplines is appropriate.[597]

EMS also concluded that ETSA Utilities' preparedness for the proposed capex program appears to be sound, based, amongst other things, on recent improvements to the project planning cycle, high quality project management, more strategic procurement and greater standardisation of designs.[598]

However, EMS concluded that ETSA Utilities may face some challenges delivering its proposed expenditure program in the early years of the next regulatory control period due to:[599]

- the need to re-assign work traditionally performed by trade skilled workers to general skilled workers by means of outsourcing to contractors alone (at least 10 per cent of work traditionally performed by trade skilled workers in the first year and 20 per cent in subsequent years)[600]
- the external demand for general skilled workers that is likely to occur in the mining and building construction sectors due to the recovery of the Australian economy
- the sheer volume of the proposed works, being more than twice the current level.

EMS noted that ETSA Utilities' proposed capex program peaks in the second year of the next regulatory control period. EMS expressed the view that due to the challenges that are likely to arise in the early years of the next regulatory control period, it is almost inevitable that some slippage will occur such that some of the works planned for 2011–12 may be delayed until later years. EMS did not review the prudency and efficiency of the proposed expenditure and offered no comment on whether any of the 2011–12 projects may be delayed without adverse effects. However, EMS noted that it may be prudent to plan now for the deferment of some early year projects rather than experiencing the inefficiencies and costs that unplanned delays inevitably create.[601]

EMS concluded that, regardless of any adjustment to the timing of projects, the total level of capex proposed by ETSA Utilities for the next regulatory control period is deliverable.[602]

AER considerations

The AER considers that ETSA Utilities appears to be well prepared for delivering its forecast capex program. In particular, the AER notes that ETSA Utilities has already significantly increased its internal resourcing to undertake some of the increased work

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597 EMS, *Deliverability of capex program proposed by ETSA Utilities*, September 2009, p. 23.
598 EMS, *Deliverability of capex program proposed by ETSA Utilities*, September 2009, p. 23.
599 EMS, *Deliverability of capex program proposed by ETSA Utilities*, September 2009, p. 23.
600 ETSA Utilities indicated that it will only explore reassignment to contractors' general skilled workers after all other practical avenues for obtaining qualified tradespeople (for example apprenticeships, recruitment) have been exhausted.
601 EMS, *Deliverability of capex program proposed by ETSA Utilities*, September 2009, p. 23.
602 EMS, *Deliverability of capex program proposed by ETSA Utilities*, September 2009, p. 23.

itself and has implemented a range of strategies to ensure that the remainder is delivered by external contractors. The AER also notes EMS's conclusion in relation to the high quality of ETSA Utilities' project management, improved project planning cycle, more strategic procurement and greater standardisation of designs.

However, the AER notes that ETSA Utilities' forecast capex program represents a significant increase compared to the level of investment undertaken in the current regulatory control period and that ETSA Utilities may face competition for resources if economic growth is stronger than currently expected. These concerns were raised in submissions and EMS cited these as potential reasons why ETSA Utilities may face some challenges delivering its proposed expenditure program in the early years of the next regulatory control period. The AER notes that despite these concerns, EMS concluded that the total level of capex proposed by ETSA Utilities for the next regulatory control period is deliverable.

Having considered ETSA Utilities' forecast capex program and proposed delivery strategies, and the advice of EMS, 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 ETSA Utilities' 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 imposed on ETSA Utilities' forecast capex program in this draft decision provides further confidence that ETSA Utilities will be able to deliver its program of works.

7.9 AER conclusion

The AER has reviewed ETSA Utilities' proposed forecast capex allowance and, for the reasons set out in this appendix, the AER is not satisfied that the proposed forecast capex allowance reasonably reflects 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. In particular the AER considers:

- the proposed demand driven capex, in particular capex associated with the low voltage network upgrade program and major customer connections, does not reflect the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capex objectives

- ETSA Utilities' proposed asset replacement capex does not reflect the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capex objectives

- the proposed security of supply capex relating to the Kangaroo Island network security project and elements of the network control project have not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the capex criteria

- ETSA Utilities' proposed safety related capex for the substation security fencing program and CBD aged asset replacement program do not reasonably reflect the efficient costs of achieving the capex objectives

- the proposed capex relating to superannuation and benchmark equity raising costs does not reflect the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capex objectives

- the expenditures associated with ETSA Utilities' application of cost escalators, including CPI, do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.

As the AER is not satisfied that the total capex allowance reasonably reflects the capex criteria, under clause 6.5.7(d) of the NER the AER must not accept the forecast capex proposed by ETSA Utilities. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of the capex for ETSA Utilities over the next regulatory control period which it is satisfied reasonably reflects the capex criteria, taking into account the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast net capex for ETSA Utilities is $1628 million, as set out in table 7.17. The AER considers these adjustments are the minimum adjustment necessary to ensure ETSA Utilities' capex forecast meets the capex criteria.

Table 7.17: AER conclusion on ETSA Utilities' capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities proposed gross capex[a]	483.8	580.6	562.5	553.5	542.5	2722.9
Customer contributions	–87.4	–93.8	–85.0	–95.0	–96.0	–457.1
Adjustment to demand driven capex	–20.3	–21.0	–21.9	–23.1	–24.6	–110.9
Adjustment to asset replacement capex	–36.0	–44.4	–50.6	–48.3	–48.1	–227.3
Adjustment to security of supply capex	–5.1	–30.3	–48.7	–19.9	–1.4	–105.4
Adjustment to safety capex	–5.6	–3.4	–2.8	–3.6	–3.4	–18.8
Adjustment to other capex	–0.3	–0.3	–0.4	–0.4	–0.4	–1.8
Adjustment to cost escalators	–16.4	–17.2	–18.8	–24.5	–30.2	–107.1
Adjustment to remove alternative control metering costs[b]	–12.7	–13.5	–12.4	–13.7	–13.9	–66.3
AER capex allowance	300.1	356.6	321.8	325.0	324.5	1628.2

Notes: Totals may not add due to rounding.

(a) Excludes proposed equity raising costs. The AER will allow ETSA Utilities to amortise a total amount of $9.2 million ($2009–10) in benchmark equity raising costs for the next regulatory control period.

(b) As discussed in chapter 2 of this draft decision, the AER has decided not to classify certain metering services as standard control services. The relevant costs have therefore been removed from ETSA Utilities' proposed capex for standard control services.

7.10 AER draft decision

In accordance with clause 6.12.1(3)(ii) of the NER the AER does not accept ETSA Utilities' forecast capex for the next regulatory control period. The AER is not satisfied that ETSA Utilities' 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 ETSA Utilities in the next regulatory period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.17 of this draft decision.

8 Forecast operating expenditure

8.1 Introduction

This chapter sets out ETSA Utilities' forecast opex, submissions from interested parties, a summary of consultants' reviews and the AER's conclusion on ETSA Utilities' opex allowance 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 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 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; and

(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 also 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 the opex criteria:

(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 opex factors:[603]

(1) the information included in or accompanying the building block proposal;

[603] NER, clause 6.5.6(e).

(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) 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 ETSA Utilities' regulatory proposal reasonably reflects the requirements of the NER, the AER has examined whether:

- ETSA Utilities' 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 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 their scope, timing, and costs

- the proposed opex requirement is commensurate with what a prudent business in the circumstances of ETSA Utilities, 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 networks, characterised by large numbers of lower value expenditure projects and ongoing programs, has defined the AER's approach to considering ETSA Utilities' proposal. Specifically:

- while a range of ETSA Utilities' projects and 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 projects reviews

- the AER has focussed on the policies, procedures and underlying assumptions, and how these have been practically applied by ETSA Utilities, both historically and in developing the opex forecasts

- with assistance from its consultant, the AER has considered more general factors (for example trends in asset age, faults) 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 ETSA Utilities.

8.4 Current period outcomes

This section summarises ETSA Utilities' actual operating expenditure outcomes compared to the allowances set by ESCOSA. The purpose of this review is to identify any cost drivers having effect during the current regulatory control period that should be recognised when assessing the forecast opex proposals for the next regulatory control period.

ETSA Utilities is expected to underspend its regulated opex allowance by approximately $22 million ($2009–10) or 3 per cent of the allowance set by ESCOSA during the current regulatory control period. This is shown in table 8.1 and figure 8.1.

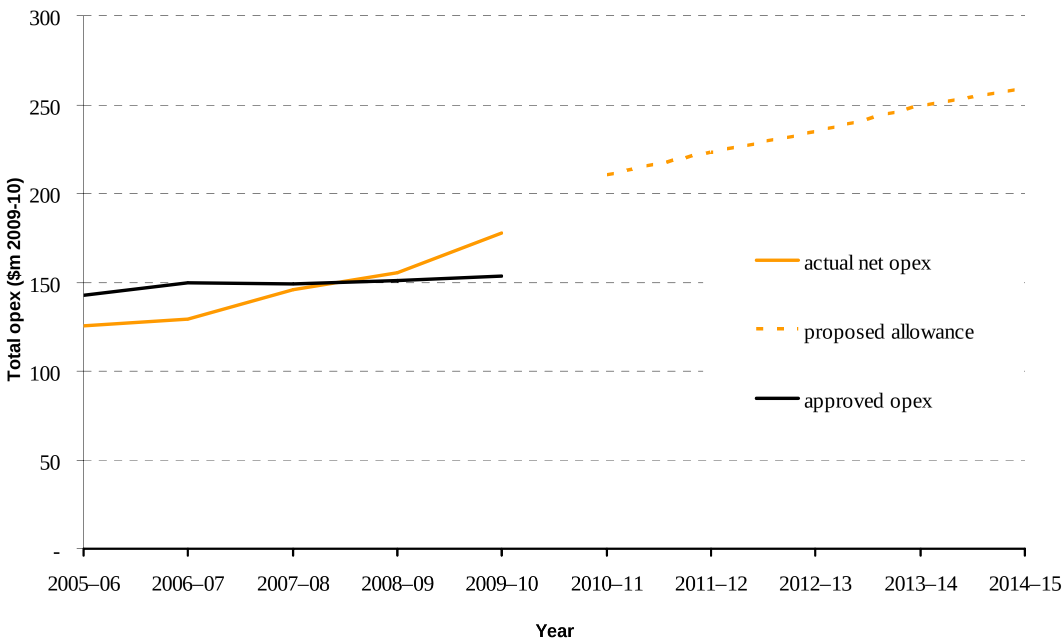
Table 8.1: ETSA Utilties opex outcomes ($m, 2009–10)

	2005–06	2006–07	2007–08	2008–09	2009–10	Total
ETSA Utilities proposed opex (incl. pass through requested)	169.9	173.7	172.8	184.6	184.7	885.7
ESCOSA approved allowance (incl. approved pass through)	143.9	152.2	151.0	154.9	153.4	755.3
ETSA Utilities actual opex	125.3	129.3	145.8	154.7	177.8	732.9
Over (underspend) % of allowance	–12.9	–15.0	–3.5	–0.1	15.9	–3.0

Source: AER analysis; ETSA Utilities, *Regulatory proposal*, July 2009, ETSA Utilities, email to AER, 28 August 2009, RIN proforma 2.2.2, converted to real terms using Australian Bureau of Statistics (ABS) data.

Figure 8.1 shows ETSA Utilities' actual and allowed total opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

Figure 8.1: ETSA Utilities actual and allowed opex ($m, 2009–10)



Source: AER analysis; ETSA Utilities, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, converted to real terms using ABS data.

ESCOSA annual performance reports

The AER has reviewed relevant annual performance reports prepared by ESCOSA. Some of the reasons identified by ESCOSA for the expected variances from the regulated allowances are set out below. Values and percentages discussed here are presented in nominal terms, unless otherwise noted.

2005–06

ETSA Utilities' total opex increased in nominal terms by 17 per cent from $98 million in 2004–05 to $115 million in 2005–06. Notwithstanding this increase in 2005–06, total opex was approximately 12 per cent below the regulated allowance (including approved pass throughs).[604]

ESCOSA noted that the storms in August 2005 and the heatwave in January 2006 had contributed to the 19 per cent increase in emergency response costs in this year. These events also contributed to increases in other costs such as guaranteed service level payments to customers affected by network outages, which was much higher than the regulated allowance.[605]

In categories where actual expenses were lower than the regulated allowances, such as in peak demand management expenditure ($1.5 million), outage management system costs ($1.2 million) and retail contestability costs ($3.9 million), ESCOSA noted these were primarily the result of timing differences due to delayed expenditure.[606]

In regard to demand management expenditure, ETSA Utilities reported actual opex of $0.9 million in 2005–06 was below the regulated allowance of $2.4 million. This underspend was attributed to the introduction of ESCOSA's demand management allowance (introduced for the current regulatory control period), and ETSA Utilities being in the planning stages of its demand management initiatives during 2005–06.[607]

2006–07

ETSA Utilities' total opex decreased in nominal terms by 3.2 per cent from $115 million in 2005–06 to $111 million in 2006–07. Total opex in 2006–07 was approximately 18.7 per cent below the regulated allowance.

Actual opex for peak demand management ($1.9 million) and retail contestability costs ($5.7 million) were lower than the regulated allowances. ESCOSA considered these differences were explained by timing variations due to delayed expenditure, as well as differences (positive and negative) reflecting combinations of weather, operational requirements and cyclical programs.[608]

ETSA Utilities total actual opex for maintenance and inspection, vegetation management and emergency response for the first two years of the 2005–10 regulatory control period was $84.5 million which was $1.8 million (2.1 per cent) below the combined regulatory allowance for these categories.

2007–08

ETSA Utilities' total opex increased in nominal terms by 18.5 per cent from $111 million in 2006–07 to $132 million in 2007–08. The major contributors to increased opex appear to be vegetation management and emergency response

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[604] ESCOSA, *2005/06 Annual performance report: Performance of South Australian energy networks*, November 2006, p. 85.

[605] ESCOSA, *2005/06 Annual performance report*, November 2006, pp. 69–72.

[606] ESCOSA, *2005/06 Annual performance report*, November 2006, p. 72.

[607] ESCOSA, *2005/06 Annual performance report*, November 2006, p. 72.

[608] ESCOSA, *2006/07 Annual performance report: Performance of South Australian energy networks*, November 2007, pp. 60–61.

expenditures. However, the overall level of total opex was approximately 7 per cent below the regulated allowance.

ETSA Utilities underspent against its regulated allowance for the categories of maintenance expenditure ($3.7 million) and retail contestability costs ($4.8 million). ESCOSA considered these differences were explained by timing differences due to delayed expenditure, as well as differences reflecting combinations of weather, operational requirements and cyclical programs.[609]

Although ETSA Utilities underspent against the total regulated opex allowance, ESCOSA noted that it overspent in the categories of maintenance and inspection, vegetation management and emergency response, which it considered were important to the distribution network reliability.[610] ETSA Utilities' total expenditure on these categories for the first three years of the regulatory control period was $137.7 million, which was 4.6 per cent above the combined regulated allowances for these categories.

8.5 ETSA Utilities regulatory proposal

ETSA Utilities' total forecast opex for the next regulatory control period is $1175 million ($2009–10), which represents an increase of $442 million, or 60 per cent, above ETSA Utilities' expected actual opex in the current regulatory control period of $733 million. Table 8.2 sets out ETSA Utilities' forecast opex by cost category for the next regulatory control period.

[609] ESCOSA, *2007/08 Annual performance report: Performance of South Australian energy networks*, November 2008, pp. 66–67.

[610] ESCOSA, *2007/08 Annual performance report*, November 2008, pp. 66–67.

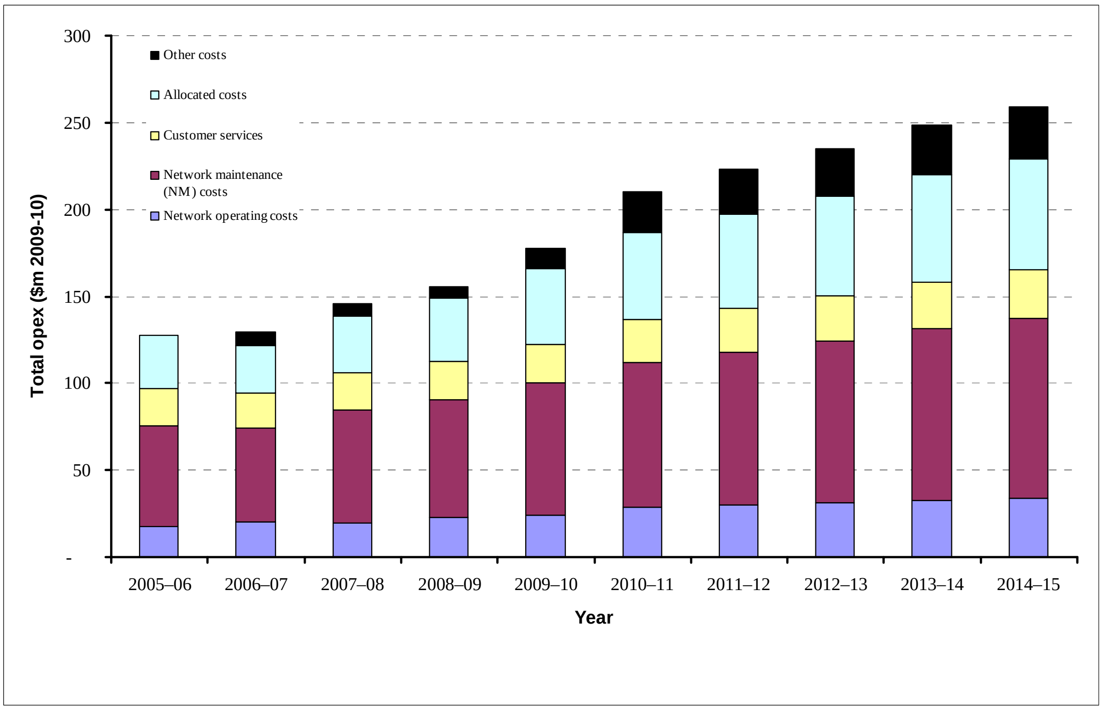
Table 8.2: ETSA Utilities forecast total opex by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Controllable opex						
Network operating costs	28.5	30.0	31.1	32.4	33.8	155.7
Network maintenance costs	83.5	87.7	93.0	99.0	103.9	467.1
Customer services	24.8	25.4	26.1	26.7	27.4	130.4
Allocated costs	49.9	54.3	57.5	62.2	63.9	287.8
Total controllable opex	186.7	197.4	207.7	220.3	229.0	1041.0
Superannuation	10.1	10.5	10.8	11.2	11.6	54.2
Feed-in tariffs[a]	5.7	6.9	7.8	8.7	9.7	38.8
Self insurance variation[b]	3.4	3.6	3.7	3.9	4.0	18.6
Debt raising costs	4.1	4.3	4.5	4.7	4.9	22.4
Proposed total opex	210.0	222.7	234.5	248.8	259.2	1175.0

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 150 and RIN opex proforma 2.2.2.
Notes: Totals may not add due to rounding.
(a) ETSA Utilities did not include an allowance for feed-in tariffs in its original submission in July 2009.
(b) Total self insurance is the summation of the baseline and variation self insurance premiums. Total controllable opex includes a level of baseline self insurance premiums. ETSA Utilities notified the AER on 15 September 2009 that its original submission in July 2009 underestimated the self insurance variation by $6 million; ETSA Utilities, email response, issue number AER.EU.25, 15 September 2009, revised schedules I–5 and R–2, confidential.

Figure 8.2 shows ETSA Utilities' actual and expected opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

Figure 8.2: ETSA Utilities actual and forecast total opex by purpose 2005–2015 ($m, 2009–10)



Source: AER analysis; ETSA Utilities, *Regulatory proposal*, July 2009, RIN proforma 2.2.2, converted to real terms using ABS data.

Controllable opex

The total controllable opex component of ETSA Utilities' forecast opex for the next regulatory control period is $1041 million ($2009–10), compared with an estimated actual expenditure of $677 million in the current regulatory control period, an increase of 54 per cent.

Table 8.3 sets out ETSA Utilities' current and forecast controllable opex by cost category and year.[611]

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611 ETSA Utilities categorises its controllable opex as total opex less superannuation, self insurance and debt raising costs.

Table 8.3: ETSA Utilities actual and forecast controllable opex by category ($m, 2009–10)

	Actual			Estimated		Forecast				
	05–06	**06–07**	**07–08**	**08–09**	**09–10**	**10–11**	**11–12**	**12–13**	**13–14**	**14–15**
Network operating	15.7	18.1	18.8	17.4	24.3	28.5	30.0	31.1	32.4	33.8
Network maintenance	51.7	49.7	61.5	76.1	75.9	83.5	87.7	93.0	99.0	103.9
Customer services	18.8	18.2	20.3	17.3	22.1	24.8	25.4	26.1	26.7	27.4
Allocated costs	27.2	25.1	31.4	43.5	43.7	49.9	54.3	57.5	62.2	63.9
Total	113.4	111.1	132.0	154.3	166.0	186.7	197.4	207.7	220.3	229.0

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN proforma 2.2.2.
Note: Totals may not add due to rounding.

ETSA Utilities' forecast controllable opex for the next regulatory control period consists of:

- network operations ($155.6 million)
- network maintenance ($467.1 million)
- customer services ($130.4 million)
- allocated costs ($287.8 million).

Almost half (45 per cent) of ETSA Utilities' forecast controllable opex for the next regulatory control period is attributed to network maintenance. This figure is consistent with the contribution of network maintenance to controllable costs in the current regulatory control period. ETSA Utilities indicated the key cost drivers for the increase in controllable opex for the next regulatory control period were:[612]

- unusual base year expenditure[613]
- changing risk profile of the distribution network
- impact of the capex program
- changes associated with economic factors

[612] ETSA Utilities, *Regulatory proposal*, July 2009, p. 151.
[613] ETSA Utilities submitted that its base year expenditure included a number of unusual expenditures that are likely to understate or overstate ETSA Utilities' longer-term efficient costs. Included in these unusual base year expenditures are vegetation management, telecommunications, debt raising costs, self insurance, regulatory proposal, demand management and finance adjustments.

- changes in regulatory, legal, or tax obligations
- changing community expectations
- other changes in scope
- scale escalation
- input cost escalation.

Superannuation, self insurance and debt raising costs

ETSA Utilities proposed to include $54 million for expensed superannuation costs, $37 million for self insurance costs and $23 million for debt raising costs for the next regulatory control period.[614]

8.6 Submissions

Business SA, Energy Users Association of Australia (EUAA), the Electricity Consumers Coalition of South Australia (ECCSA), SA Water, UnitingCare Wesley (UCW), the South Australian Council of Social Service (SACOSS), and the Council on the Ageing (COTA), made comments in their submissions relating to ETSA Utilities' proposed forecast opex proposal. In summary, interested parties raised issues regarding:

- magnitude of the total opex increase – submissions raised concerns about the overall size of the proposed opex and requested the AER to focus on the necessity and justification of the opex program.[615]
- proposed real cost escalations for labour and materials – submissions were concerned about a variety of factors surrounding real cost escalations, including concerns about incentives for productivity improvements if businesses are compensated for above CPI cost increases and the rate of forecast wage growth in the next regulatory control period.[616]
- benchmarking – the submissions considered benchmarking as a useful tool in assessing the efficiency of the proposed opex program.[617] In particular, the EUAA submitted that the AER was required to undertake benchmarking analysis of proposed opex under the NER.[618]

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[614] ETSA Utilities, *Regulatory proposal*, July 2009, p. 150.
[615] Business SA, *Submission to the AER*, August 2009, p. 3; and SA Energy Minister, *Submission to the* AER, September 2009.
[616] ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 20–23; Business SA, *Submission to the AER*, August 2009, p. 9; and UCW, *Distribution price review for South Australia*, p. 19.
[617] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 44,; EUAA, *Submission to the AER*, 28 August 2009, pp. 4 and 8–9; and SA Energy Minister, *Submission to the* AER, September 2009, p. 1.
[618] EUAA, *Submission to the AER*, 28 August 2009, p. 4 and pp. 8–9.

- incentives for demand management – several submissions accepted that if the AER deems a demand management project to be justified, then an increase in demand management expenditure may be appropriate.[619] SACOSS stated that ETSA Utilities was now ready to deliver significant demand management projects.[620] Several submissions also suggested that the AER's current approach to demand management did not provide enough incentives for businesses to pursue demand management.[621]

- capex/opex trade off – the ECCSA stated that the proposed capex program should have a greater efficiency effect on the opex program than stipulated by ETSA Utilities.[622]

- step changes – the ECCSA questioned the size and drivers of the proposed step changes and the method the AER should use to analyse these step changes.[623]

- base year – ECCSA commented on ETSA Utilities' choice of base year, and stated that the use of the fourth year in current period as an efficient base year encourages ETSA Utilities to ramp up expenditure towards the end of the current regulatory control period.[624]

- debt and equity raising costs – two submissions raised concerns about ETSA Utilities' debt and equity raising costs. The EUAA stated that the AER should examine ETSA Utilities' proposed costs in the context of actual costs.[625] ECCSA stated that debt raising costs are already covered in the opex allowance, and that only a new element for additional debt that is required to fund the capex program should be considered.[626]

- reliability expenditure – COTA commented that the 2002 'Willingness to Pay' study indicated that SA consumers were not willing to pay for increased supply reliability. COTA raised concerns that ETSA Utilities was justifying its increased opex partly on a false premise.[627]

These submissions are discussed in further detail in this chapter. Where the AER has considered it appropriate to directly address these submissions, it has done so in the relevant sections throughout this chapter.

8.7 Consultant review

The AER engaged PB to provide an independent assessment of ETSA Utilities' forecast opex proposal. PB adopted a two-stage review process consisting of an initial

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619 Business SA, *Submission to the AER*, August 2009, p. 7; and ECCSA, *ETSA Utilities application, a response*, August 2009, p. 38.
620 SACOSS, *Submission to the AER*, August 2009, p. 4–5.
621 Business SA, *Submission to the AER*, August 2009, p. 7; EUAA, *Submission to the AER*, 28 August 2009, pp. 10–11; and SACOSS, p. *Submission to the AER*, August 2009, pp. 4–5.
622 ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 29 and 37.
623 ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 10, 24, 29 and 38.
624 ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 29–30.
625 EUAA, *Submission to the AER*, 28 August 2009, p. 11.
626 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 37.
627 COTA, *ETSA distribution price review*, August 2009, p. 3.

high-level review, followed by a more detailed investigation into areas of particular materiality or variance. The objectives of PB's staged process were aimed at:[628]

- reviewing and understanding the business as usual asset management approach and practice, including relevant policies and procedures, from both a technical and commercial perspective
- reviewing and understanding the expenditure forecasting methodology and modelling used, with a strong view to being informed of the scope of work proposed; understanding changes proposed by the business; and the drivers presented by the business for any notable and material changes.

PB's review included an assessment of:[629]

- the efficiency of the forecast opex for each year of the next regulatory control period, and whether there is any further scope for efficiencies
- the appropriateness of the allocation of opex costs to specific activities
- 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:
  - assessing the efficiency of the base year selected
  - 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
  - investigating the design and output of ETSA Utilities' opex model, which informs the directly attributed regulated opex services in terms of 24 separately identified services and through 41 separately identified allocated cost categories
  - 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.

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[628] PB, *Report – ETSA Utilities*, October 2009, p. 5.
[629] PB, *Report – ETSA Utilities*, October 2009, p. 5.

Based on its review, PB found that 96 per cent of ETSA Utilities' $1175 million proposed opex was prudent and efficient, but recommended that the forecast opex be reduced by $46 million.[630] PB's key findings are as follows:[631]

- 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

- asset maintenance and management practices are in a transitional stage – moving from a lagging indicator and fixed time-based inspection approach, to a future state capturing more condition based knowledge and informed through leading indicators

- the base year opex of $155m for 2008–09 is prudent and efficient for the purposes of informing the forecasts

- ETSA Utilities has provided a clear description of how and why it established and applied scale escalators, and PB is generally satisfied that network size, work volume, workforce size and customer growth are each factors that will influence opex requirements and has used a reasonable level of discretion in selecting the activities to which each of the factors apply.

PB recommended the following indicative adjustments to ETSA Utilities' proposed opex:

- a reduction of $9.9 million to account for a network growth factor that better reflects the actual assets that will be installed from a bottom–up perspective

- a reduction in the total network access, monitoring and control opex activity of $2.7 million based on a bottom–up forecast of staff required to undertake this activity

- a reduction in the total emergency response opex activity of $8.7 million to reduce the growth escalation, on the basis that new assets are not likely to fail consistently and repeatedly in an unplanned manner

- a reduction of $0.3 million to account for the asset replacement capex / opex trade off

- a reduction of $19.5 million is made to remove the escalation in network maintenance opex due to increasing asset age. This change has not been substantiated primarily due to the lack of calibration of the Sinclair Knight Merz (SKM) age versus opex characteristics to ETSA Utilities' existing asset base and classes

- a reduction of $4.8 million is made to remove the 5 per cent contingency allowance included in the proposed vegetation management.

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630 PB, *Report – ETSA Utilities*, October 2009, p. 169.
631 PB, *Report – ETSA Utilities*, October 2009, pp. 166–167.

PB's specific findings on each area of ETSA Utilities' forecast controllable opex proposal are discussed in section 8.8 of this draft decision.

8.8 Issues and AER considerations

8.8.1 Controllable opex

The AER must determine whether ETSA Utilities' opex forecast reasonably reflects the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the opex objectives, and a realistic expectation of the demand forecast and cost inputs required to achieve the objectives.[632] The AER engaged PB to assist it in assessing the controllable components of ETSA Utilities' opex forecasts.

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 ETSA Utilities' opex proposal is prudent and efficient, and satisfies the requirements of chapter 6 of the NER.

The AER notes that the majority of issues raised by interested parties in their submissions have been considered in its assessment of ETSA Utilities' forecast opex. In particular, the submissions expressed general concerns about the large increases in opex relative to historical expenditure and the need for the AER and consumers to be satisfied that the proposed allowances are necessary. The AER considers that these concerns have been appropriately considered in PB's assessment, and its own independent consideration of ETSA Utilities' opex proposal, based on the approach discussed in section 8.3. Specifically, the AER and PB assessed, among other things:

- the appropriateness of the forecasting methods and procedures used by ETSA Utilities, including reviewing the allocation of costs in accordance with the AER approved cost allocation method (CAM)

- the efficiency of ETSA Utilities' forecast opex and base year, using detailed bottom up methods where possible, and with reference to benchmarking studies

- the impact and reasonableness of proposed real input cost escalators and network scale/growth escalators

- step changes in opex, the rationale for those changes and the associated efficiency benefits

- the scope for capex/opex trade offs and demand management initiatives.

In addition, the AER has undertaken analysis of the reasonableness and efficiency of ETSA Utilities' proposed uncontrollable opex. These considerations are set out in section 8.8.3 to 8.8.6.

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632 NER, clause 6.5.6.

The AER's review of forecast opex is undertaken separately to its review of input cost escalators (section 8.8.1.5 of this draft decision). The impact of revisions to input cost escalators is therefore not factored into the AER conclusions presented on forecast opex. The consolidated impact of all adjustments required by the AER (controllable opex, uncontrollable opex, capex, and real cost escalation) is set out in the AER conclusions (section 8.9 of this draft decision).

The AER considerations on ETSA Utilities' forecast opex proposal are set out below.

8.8.1.1 Opex forecasting methodology

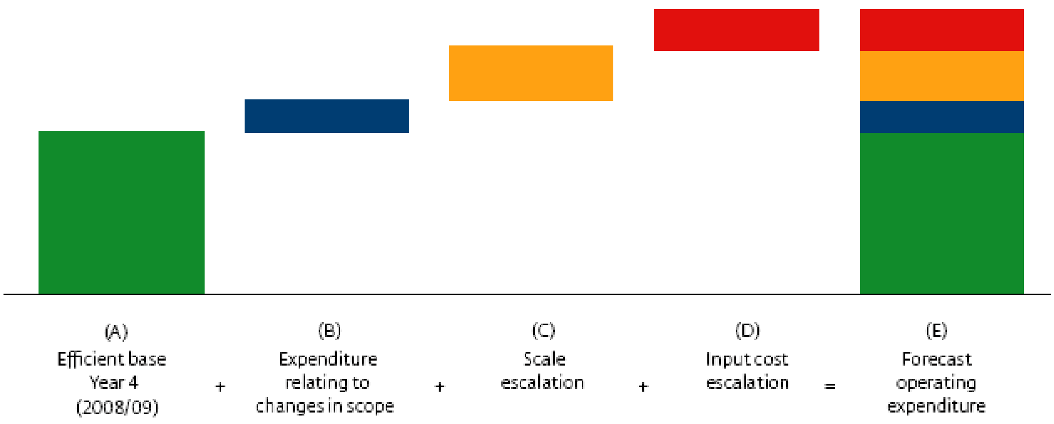
ETSA Utilities regulatory proposal

ETSA Utilities stated its process for developing the opex forecast involved:[633]

- defining an efficient base year (2008–09)
- where applicable, adjusting the opex incurred in the base year to account for changes in scope
- applying scale escalation to each opex category, depending on the drivers that impact upon each category
- applying input cost escalators, reflecting real increases in the cost of labour, materials and services, to each opex category.

ETSA Utilities defined expenditure relating to a change in 'scope' to represent either an increase or a decrease in the activities carried out in delivery of standard control services. It defined 'scale escalation' as a change in the volume of existing activities carried out by ETSA Utilities. Its process is illustrated in figure 8.3.

Figure 8.3: ETSA Utilities opex forecasting process



Source: ETSA Utilities. *Regulatory Proposal*, July 2009, p. 147.

633 ETSA Utilities, *Regulatory proposal*, July 2009, p. 147.

Submissions

Business SA, ECCSA, SA Water and UCW made comments in their submissions about components of ETSA Utilities' proposed opex forecasting methodology. These comments are presented and addressed in the following specific opex forecasting methodology sections of the draft report; efficient base year, proposed step changes, scale escalation and cost escalators.

Consultant review

PB reviewed ETSA Utilities' forecasting methodology and considered it to be logically constructed, soundly applied and generally well considered. In particular, PB noted that:[634]

- the integrated opex model outlining each of the 21 direct cost opex activities and the 41 allocated cost activities includes a high degree of transparency, with excellent labelling and cross-referencing

- ETSA Utilities' opex model treats each activity in a systematic manner and appears refined and of a high professional standard and quality. PB noted that this is consistent with the evidence provided by ETSA Utilities that many aspects of its proposal have been independently reviewed by its consultants SKM and KPMG

- ETSA Utilities' opex model is well supported by over 145 supporting documents that clearly identify the data and sources of key assumptions used by ETSA Utilities to inform its opex forecasts.

At a high level, PB considered the general modelling approach adopted by ETSA Utilities to develop its opex forecasts to be reasonable and practical.[635]

AER considerations

The AER considers that it is often appropriate to prepare opex forecasts using a baseline/scope change methodology and/or a bottom–up approach, and notes ETSA Utilities applied both of these methods to elements of its opex forecasts.

In both cases the key issues for the AER are whether the methodology has been correctly applied, and whether the assumptions and data used to develop the forecasts are reasonable and verifiable. The AER has considered the assumptions and data in its review of specific components of the opex forecasts in sections 8.8.1.7–8.8.1.10 of this draft decision.

The AER notes that ETSA Utilities developed a detailed and transparent model, including itemised allocated costs, to forecast its opex for the next regulatory control period. ETSA Utilities has applied the CAM to expense its overheads.[636] The AER also notes that where variations to the base year are included, ETSA Utilities has provided details of the variations and how they were calculated.

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[634] PB, *Report – ETSA Utilities*, October 2009, p. 136.
[635] PB, *Report – ETSA Utilities*, October 2009, p. 136.
[636] ETSA Utilities, *Cost Allocation Method*, September 2008.

The AER notes that ETSA Utilities' vegetation management and demand management initiatives were forecast on a detailed bottom–up basis. ETSA Utilities provided supporting information for its bottom–up forecasts of these two opex cost categories.

AER conclusion

The AER has considered ETSA Utilities' opex forecasting methodology, opex models, supporting information and independent advice from PB. On the basis of its review the AER is generally satisfied that ETSA Utilities' opex forecasting methodology is transparent and appropriate. Where this is not the case, the AER has concluded that specific adjustments should be made to the forecast opex proposed by ETSA Utilities.

As a result of its analysis and ETSA Utilities' opex forecasting methodology and supporting documents, the AER is satisfied that ETSA Utilities' forecasting methodology is suitable for forecasting its opex requirements for the next regulatory control period.

8.8.1.2 Capex/opex trade off

ETSA Utilities identified and assessed three key aspects of its capex and opex forecasts for the purpose of evaluating capex and opex substitution alternatives:[637]

- ageing of assets
- investment in new systems, processes, plant and equipment
- purchase verses lease of new equipment or facilities.

ETSA Utilities undertook an assessment of the age and condition of its electricity distribution network assets, and other major asset classes.

ETSA Utilities engaged SKM to model the impact of its forecast capex program on the average age of its distribution network, and the likely impact this would have on its opex. SKM utilised an existing 2008 asset age profile provided by ETSA Utilities and separately modelled new and replacement asset programs based on ETSA Utilities' forecast capex for the next regulatory control period. SKM applied opex/age relationships developed in previous studies to calculate the impact of aging assets on ETSA Utilities' operating costs. SKM provided detailed projections of the average age of ETSA Utilities' network, in addition to the proportion of network assets that reached or exceeded their standard life, from 2008 to the end of the next regulatory control period in 2015.[638]

SKM determined that the average age of assets that comprise ETSA Utilities' electricity distribution network will increase to 39 years by the end of the next regulatory control period, compared to 36 years during the 2008–09 base year.[639]

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637 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 177–180.
638 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs,* 15 May 2009.
639 ETSA Utilities, *Regulatory proposal*, July 2009, p. 179.

SKM also estimated that this increase in asset age will result in additional annual opex of about 1.5 – 2 per cent per annum during the next regulatory control period.[640] ETSA Utilities incorporated a forecast of the additional opex associated with this increase in its opex forecast.

ETSA Utilities submitted that its capex and opex forecasts represent the optimal mix of asset replacement, and enhanced condition monitoring, by which cost and risk are balanced.[641]

ETSA Utilities also reported that it undertook a line by line review of its categories of forecast capex to determine the implications for its forecast opex. ETSA Utilities identified that the majority of capex, linked to expansion of the electricity network, will result in increased opex due to the increase in the number of assets that must be inspected and maintained. ETSA Utilities also identified opex increases associated with the asset replacement and strategic projects elements of its proposed capex program.

Submissions

The ECCSA submitted that the significant increases in capex projects should provide for much larger efficiency savings in capex/opex trade offs, productivity savings and savings from maintenance programs no longer required on replaced assets.[642]

Consultant review

PB reported that while it concurs with the principle that an aging asset base will generally require additional maintenance, if the average asset age is approaching the end of its expected service life, it had a number of reservations about the wide-ranging application of the escalators prepared by SKM and applied by ETSA Utilities.[643] PB concluded that the framework employed by SKM and applied by ETSA Utilities for determining the asset age and opex relationships was generally sound, but it was not appropriate to determine the capex/opex trade off due to the lack of calibration of the opex/age curves with ETSA Utilities' actual assets and asset management approach.[644] In particular, PB noted that the accuracy of the SKM model is fundamentally dependent on a calibrated age versus opex characteristic, yet the asset management practices or opex costs for ETSA Utilities have not been reconciled or aligned to ensure the age versus opex curves are appropriate.[645]

PB determined a capex/opex trade off by calculating the annual ratio of compounding asset replacement expenditure (as recommended by PB) to the current (undepreciated) replacement cost of the asset base. PB then applied 20 per cent of this ratio to calculate the recommended adjustment in the maintenance and repair forecast opex. PB stated that the 20 per cent factor accounts for reduced defect requirements with replaced assets, and reflects the proportion of total maintenance that is typically experienced by DNSPs associated with rectifying defects compared with the amount

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640 ETSA Utilities, *Regulatory proposal*, July 2009, p. 180.
641 ETSA Utilities, *Regulatory proposal*, July 2009, p. 178.
642 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 29.
643 PB, *Report – ETSA Utilities*, October 2009, p. 153.
644 PB, *Report – ETSA Utilities*, October 2009, pp. 143–144.
645 PB, *Report – ETSA Utilities*, October 2009, p. 153.

associated with routine inspections and maintenance. PB stated that this proportion has been identified as typical, based on PB's experience working with a number of network operators across Australia. On the basis of its analysis, PB recommended a reduction in ETSA Utilities' proposed maintenance and repair to account for the asset replacement capex trade off of $0.3m during the next regulatory control period.[646]

AER considerations

The AER notes the reservations about the asset age escalators applied by ETSA Utilities highlighted by PB, in particular PB's reservation about the calibration of the opex/age curves with ETSA Utilities' actual assets and asset management approach. The AER considers that ETSA Utilities has not appropriately modelled the likely impact of asset age on its opex forecast, as it has not accurately calibrated the opex/age curves used in the modelling.

Given ETSA Utilities has not, in the opinion of the AER and PB, adequately modelled expected capex/opex trade offs, the AER considers it reasonable to incorporate a substitute trade off estimate into the forecast opex modelling. The AER considers that the financial ratio methodology PB used to determine the capex/opex trade off is sound, well considered, and is likely to reasonably reflect the impact of the asset replacement capex program on ETSA Utilities' proposed maintenance and repair opex.

In considering ETSA Utilities proposal and PB's recommended capex/opex trade off adjustment, the AER has been cognisant of the potential impact on the opex forecast of its conclusions on ETSA Utilities' forecast asset replacement capex discussed in chapter 7.

The AER's reduction to ETSA Utilities forecast asset replacement capex has been determined on the basis that the expenditure is not demonstrated to be prudent or efficient. In forming this view the AER noted that much of ETSA Utilities' forecast replacement capex program relied on age based forecasting in addition to ETSA Utilities' existing condition based forecasts.[647] The AER considers a condition based asset replacement approach which factors in many asset variables (such as for example, age, defect history and physical conditions) is prudent and will likely point towards an efficient outcome.

The AER also acknowledges that, in order to realise the longer term benefits of an efficient condition based replacement strategy, ETSA Utilities will need to incur additional operating costs in the shorter term, for example, relating to data collection and management and establishing maintenance strategies and systems.

The AER has taken these factors into account, and considers that the capex/opex trade off proposed by PB is reasonable given ETSA Utilities circumstances, including the impact of other aspects of this draft decision. ETSA Utilities was asked to remodel its maintenance and repair opex to taken into account the explicit capex/opex trade off adjustment and the revised asset replacement capex forecast. ETSA Utilities advised

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[646] PB, *Report – ETSA Utilities*, October 2009, pp. 144–145.
[647] PB, *Report – ETSA Utilities*, October 2009, p. 70.

the impact of this adjustment was a reduction of $0.3 million to maintenance and repair opex.

The AER also notes that PB's assessment of ETSA Utilities' asset replacement capex trade off also impacts on the asset age escalation applied by PB to ETSA Utilities' proposed maintenance and repair and emergency response opex. Details of this impact on proposed maintenance and repair and emergency response opex is provided in section 8.8.1.4 of this draft decision.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is not satisfied that ETSA Utilities' forecasts for maintenance and repair opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

8.8.1.3 Efficient base year

ETSA Utilities regulatory proposal

ETSA Utilities used 2008–09 opex as the base year for forecasting opex in the next regulatory control period. ETSA Utilities stated it selected 2008–09 as its efficient base year because:

- it is the most recent year of actual performance, with audited regulatory accounts available, before the AER is required to make its final determination
- it better reflects the global economic conditions that are expected to prevail during the next regulatory control period
- it aligns ETSA Utilities' opex forecast with the application of the efficiency carryover mechanism (ECM) applying to ETSA Utilities in the current regulatory control period.[648]

ETSA Utilities considered that top–down benchmarking provides a useful indicator in assessing proposed opex.[649] In its assessment of the benchmarking analysis undertaken by Wilson Cook & Co for the AER, ETSA Utilities claimed that there is no reason to consider that ETSA Utilities base year opex is inefficient.[650] ETSA Utilities also claimed that other benchmarking demonstrates similar results.[651] ETSA Utilities stated it would be appropriate for the AER to consider the top–down benchmarking analysis undertaken by Wilson Cook & Co in supporting the AER's detailed, bottom–up assessment of ETSA Utilities' proposed opex.[652] Overall, ETSA

[648] ETSA Utilities, *Regulatory proposal*, July 2009, p. 148.
[649] ETSA Utilities, *Regulatory proposal*, July 2009, p. 146.
[650] ETSA Utilities, *Regulatory proposal*, July 2009, p. 147.
[651] ETSA Utilities, *Regulatory proposal*, July 2009, p. 147.
[652] ETSA Utilities, *Regulatory proposal*, July 2009, p. 181.

Utilities submitted that the efficiency of its opex forecast in the next regulatory control period is demonstrated through benchmarking.[653]

ETSA Utilities claimed its base year costs have been calculated from its forecast regulatory accounts for 2008–09, adjusted to comply with the approved cost allocation methodology for 2005–2010, and with both superannuation and self-insurance adjusted to a cash basis.[654]

Submissions

The ECCSA contended that using 2008–09 as the base year provided incentives for ETSA Utilities to increase opex in that year, despite the efficiency benefit sharing scheme (EBSS).[655] The ECCSA supported the use of the average opex over the current regulatory control period as the start point for step changes for forecasting opex for the next regulatory control period.[656]

The ECCSA stated that benchmarking a DNSP is the most effective approach to setting a reasonable opex forecast. The ECCSA stated that the opex allowed by ESCOSA for the current regulatory control period allowed ETSA Utilities to accrue a considerable benefit from underspending its opex allowance for much of the current regulatory control period.[657]

The EUAA stated that the AER is required to have regard to the benchmark opex that would be incurred by an efficient DNSP in the calculation of the maximum allowed revenue for ETSA Utilities for the next regulatory control period.[658] The EUAA stated that the opex benchmarking work undertaken by Wilson Cook was not satisfactory in terms of the AER's benchmarking obligations under the NER.[659]

The EUAA suggested that the AER develop a comparative analysis to provide systematic comparisons that take account of the exogenous and endogenous factors that affect comparisons between DNSP expenditures.[660]

Consultant review

PB concluded that the 2008–09 base year opex of $155 million is prudent and efficient for the purposes of informing the opex forecasts.[661] PB based its conclusion on the following considerations:[662]

- ETSA Utilities submitted a detailed level of resolution of the disaggregated business as usual regulatory account data for 2008–09 to support its claim

653 ETSA Utilities, *Regulatory proposal*, July 2009, p. 148.
654 ETSA Utilities, *Regulatory proposal*, July 2009, p. 148.
655 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 29.
656 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 30.
657 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 44.
658 EUAA, *Submission to the AER*, 28 August 2009, p. 8.
659 EUAA, *Submission to the AER*, 28 August 2009, p. 8.
660 EUAA, *Submission to the AER*, 28 August 2009, p. 9.
661 PB, *Report – ETSA Utilities*, October 2009, p. 136.
662 PB, *Report – ETSA Utilities*, October 2009, p. 137.

- an analysis of movement in opex categories between 2007–08 and 2008–09, where expenditure in 19 categories decreased, 37 categories increased and two categories remained constant, suggested that ETSA Utilities adopted a balanced and transparent approach in selecting the base year

- it is the most current data available and audited results will be available to the AER at the time of its final determination

- it appropriately accounts for the latest AER approved CAM and finance adjustments

- the top–down review of comparative benchmarking showed ETSA Utilities' historical opex for 2007–08 to be relatively efficient (notwithstanding the limitations such a simple analysis inherently includes) and this finding can be reasonably extrapolated to 2008–09. PB considered that, although the historical opex for 2008–09 is 7 per cent higher than 2007–08, all the businesses benchmarked are likely to have experienced a similar (small) annual increase in opex

- the asset management practices outlined in the various asset management plans of ETSA Utilities are transparent and reasonable.

AER considerations

The AER has reviewed the movement in opex for ETSA Utilities for the current regulatory control period and notes that the increase in opex between 2007–08 and 2008–09 of around 6.5 per cent is significantly less than that between 2006–07 and 2007–08 (12.8 per cent) and the projected movement between 2008–09 and 2009–10 (14.5 per cent), and more than the movement between 2005–06 and 2006–07 (3.2 per cent). The increase in opex between 2007–08 and 2008–09 provides support for the proposition that ETSA Utilities has not unreasonably increased opex during 2008–09. The AER also notes that the ECM scheme administered by ESCOSA provides an incentive for ETSA Utilities not to increase opex during the current regulatory control period.

PB concluded that ETSA Utilities has taken a balanced and transparent approach in selecting the 2008–09 base year, supporting the AER's observation that ETSA Utilities has not unreasonably increased opex during 2008–09. Further, PB noted that ETSA Utilities appears to have removed any abnormal expenditures from the base year where relevant.[663]

The AER also compared ETSA Utilities' actual opex for its base year with its efficient opex allowance determined by ESCOSA, and notes that ETSA Utilities overspent its opex allowance (including approved pass throughs) by 0.5 per cent.[664] This outcome further supports the conclusion that ETSA Utilities did not unreasonably increase its opex during 2008–09.

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[663] PB, *Report – ETSA Utilities*, October 2009, p. 137.

[664] ETSA Utilities, *Regulatory proposal*, July 2009, p. 145, *Draft Regulatory Financial Report for the year ended 30 June 2009*.

Benchmarking

The NER sets out the factors that the AER must consider when assessing whether or not it is satisfied by a DNSP's forecast opex.[665] In determining whether or not the proposed forecast opex meets the opex criteria, AER must have regard to the opex factors, which include:[666]

> benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.

The AER undertook benchmarking analysis, including ratio and regression analysis of measures of ETSA Utilities' 2007–08 opex, and forecast opex, against other Australian DNSPs.

The AER provided its ratio analysis to PB. PB considered the results and concluded that ETSA Utilities' opex forecasts appear relatively efficient from a top–down perspective when compared to the other businesses in the sample. However, PB identified several reasons why ETSA Utilities may differ from other businesses:[667]

- all overheads are expensed
- almost exclusive use of concrete and steel stobie pole design has fundamental differences as a key asset class within a distribution network compared with round wood poles used elsewhere
- a mix of CBD, urban and rural type networks.

Figure 8.4 shows the results of the AER's regression analysis for DNSPs in Australia.

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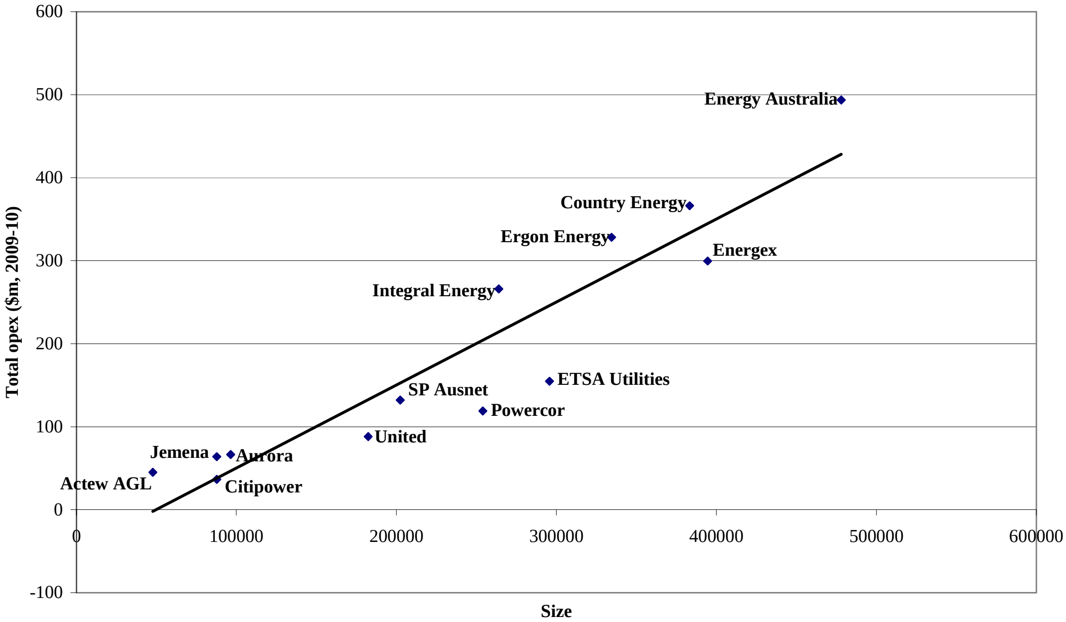
665 NER, clause 6.5.6(e)(1)–(10).
666 NER, clause 6.5.6(e)(4)
667 PB, *Report – ETSA Utilities*, October 2009, p. 166.

Figure 8.4: Comparative analysis of opex vs. size for Australian DNSPs ($m, 2009–10)



Source: AER, internal analysis.

Consistent with the ratio analysis undertaken by the AER, the AER's regression modelling also shows ETSA Utilities slightly below the regression line, indicating it has relatively low opex, in comparison to other DNSPs in the sample. This analysis takes into account factors like the relative size of the DNSPs' networks, and has used data gathered on a like for like basis, to the extent possible.

The AER notes the comments of the EUAA, regarding the AER's obligation to undertake benchmarking when reviewing opex forecasts. In particular, the EUAA seemed to be requesting that the opex forecast be adjusted largely on the basis of benchmarking studies.[668] The AER also notes that the ECCSA claim that benchmarking is the most effective approach to forecasting opex.[669]

However, the limitations of the benchmarking work, in terms of the size of the data set, discrepancies in opex definitions and differing regulatory arrangements for comparable DNSPs limits the use of the benchmarking results as a tool for directly determining adjustments to opex forecasts. The AER also considers the general limitations of benchmark analysis are recognised by the NER as benchmarking is only one of ten factors that the AER must have regard to when assessing a DNSP's proposed opex forecasts.

The AER therefore considers that, while benchmarking is a useful high-level analytical tool, it will currently limit its use to a top–down testing of more detailed

[668] EUAA, *Submission to the AER*, 28 August 2009, pp. 8–9.
[669] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 44.

bottom–up assessment, informed by due consideration of each of the factors specified in clause 6.5.6(e) of the NER.

As required under clause 6.5.6(e)(4) of the NER, the AER has had regard to benchmarking information as provided by ETSA Utilities, and its own internal analysis. The AER notes the outcomes of these benchmarking studies, and observes that ETSA Utilities' opex appears relatively low in 2007–08 compared to the sample. The AER considers there are reasonable explanations for this outcome, and has considered these factors in its assessment of the prudence and efficiency of ETSA Utilities' base year opex, and forecast opex for the next regulatory control period.

AER conclusion

Given ETSA Utilities' actual opex in the base year has been verified by an audit of the regulatory information provided to the AER, and the overspend in comparison to the regulatory allowance is insignificant, the AER considers it represents an efficient amount from which to forecast opex in the next regulatory control period.

8.8.1.4 Proposed step changes

ETSA Utilities regulatory proposal

ETSA Utilities' methodology for developing its opex forecast, described in section 8.8.1.1, reveals a larger step change in opex between the final year of the current regulatory control period and the start of the next regulatory control period, than between successive years in the next regulatory control period. Between 2009–10 and 2010–11, ETSA Utilities has proposed an opex increase of $25.4 million (14.3 per cent) compared to average opex increase of $11.3 million per annum (5.1 per cent) in the next regulatory control period.[670]

ETSA Utilities indicated that more than 60 per cent of its identified changes in scope relate to a change commencing in 2009–10, 35 per cent relate to a change commencing in 2010–11 and less than 5 per cent relate to a change commencing in 2011–12. The influence of the scope changes in 2009–10 and 2010–11 is reflected in the large step change in opex between 2009–10 and 2010–11.

Impact of external factors

ETSA Utilities identified specific changes in scope that will impact on its ability to maintain its levels of service risk and compliance in the lead up to, and during, the next regulatory control period. The key external drivers impacting on ETSA Utilities' opex were:

- unusual base year expenditure (average $12.8 million per annum)
- changes associated with the risk profile of the distribution network (average $6.7 million per annum)
- opex associated with the capex program (average $6.2 million per annum)

[670] ETSA Utilities, *Regulatory proposal*, July 2009, p. 150.

- changes associated with economic factors (average $4.7 million per annum)
- changes in regulatory, legal or tax obligations (average $3.0 million per annum)
- changes associated with changing community expectations (average $0.9 million per annum)
- other changes in scope (includes full retail contestability (FRC) systems support, aerial inspections and Davenport Training Centre) averaging $3.5 million per annum.

Submissions

The ECCSA challenged the basis for step adjustments to the opex base year. The ECCSA identified vegetation management, telecommunications, debt raising costs, self-insurance, regulatory proposal expense, demand management, finance adjustment and changes as a result of the risk profile as cost categories that the AER should challenge the step adjustments proposed by ETSA Utilities.[671]

Consultant review

PB considered the approach adopted by ETSA Utilities to identify the individual scope changes as a reasonable and pragmatic process that should adequately inform the forecasts of new opex requirements. In particular, PB reported it was satisfied the process was comprehensive and objective as it:[672]

- excluded any speculative scope changes towards the end of the next regulatory control period
- it was based on long-term planning processes
- it included numerous reviews culminating in formal executive management approval prior to inclusion in ETSA Utilities' regulatory proposal.

PB reviewed the various scope changes identified by ETSA Utilities in the proposed network operations, network maintenance, customer services and allocated cost categories.[673]

PB reviewed the following proposed scope changes in relation to ETSA Utilities' network operations related activities:[674]

- asset strategy and planning
  - additional labour resources to review condition monitoring data and develop/revise asset management strategies

[671] ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 37–39.
[672] PB, *Report – ETSA Utilities*, October 2009, p. 137.
[673] PB, *Report – ETSA Utilities*, October 2009, p. 137.
[674] PB, *Report – ETSA Utilities*, October 2009, pp. 145–148.

- resources to facilitate the establishment of a new workgroup responsible for capacity planning of LV assets
- establishment of a dedicated substation asset management and condition monitoring team

- maintenance planning
  - additional labour resources to analyse condition monitoring data and plan maintenance of powerline assets
- network telephony
  - additional expenditure associated with the program of data link upgrades during the current regulatory control period
  - implementation of an intensified condition monitoring regime for telephony assets.

PB concluded that all of the network operations scope change allowances were prudent and efficient.[675]

PB reviewed the following proposed scope changes in relation to ETSA Utilities' network maintenance related activities:[676]

- inspections
  - change in the scope of ETSA Utilities' service contract with its aerial inspection services provider
  - resources to facilitate more frequent inspections of powerline assets as part of ETSA Utilities' condition monitoring strategy
  - additional labour resources to facilitate more frequent and detailed asset inspections in high corrosion risk areas
  - resources to facilitate more detailed inspection of substation assets as part of ETSA Utilities' condition monitoring strategy
- maintenance and repair
  - additional resources to facilitate delivery of a meter inspection and testing program that complies with new requirements
  - costs associated with non–network solutions (peak lopping generation)
  - additional opex associated with an increase in average asset age

[675] PB, *Report – ETSA Utilities*, October 2009, p. 148.
[676] PB, *Report – ETSA Utilities*, October 2009, pp. 149–157.

- emergency response—additional opex associated with an increase in average asset age
- demand management innovation allowance (DMIA)—agreed allowance for demand management activities
- network insurance—increase in insurance premiums.

PB concluded that the expenditure categories inspections, maintenance and repair, DMIA and network insurance scope change allowances to be prudent and efficient.[677]

PB was of the view that the proposed scope variations associated with an increase in average asset age for the maintenance and repair and emergency response categories relate to asset age escalation. On the basis of its reservations about the wide-ranging application of the escalators prepared by SKM and applied by ETSA Utilities, discussed in section 8.8.1.2 of this report, PB stated that the proposed increases in opex due to increasing asset age for these two expenditure categories have not been substantiated.

PB concluded that the proposed increases are not prudent and efficient scope changes and should be removed from the maintenance and repair and emergency response opex forecasts. PB recommended a reduction of $6.2 million to maintenance and repair and $13 million to emergency response in the next regulatory control period.[678]

While PB assessed the increased vegetation management allowance proposed by ETSA Utilities as reasonable and prudent given its current non–compliance and potential safety issues, it considered the 5 per cent contingency allowance for external costs was not prudent or efficient as the scope of work was not specified by ETSA Utilities. On this basis, PB recommended that the proposed contingency allowance of $4.8 million in the next regulatory control period be removed from the vegetation management expenditure category.[679]

PB reviewed the one scope change for customer services opex relating to additional expenses associated with changes in the FRC systems supported by CHED Services. PB concluded that although the margins achieved by CHED Services appear to be high, the synergies ETSA Utilities achieved in outsourcing these services results in lower costs than providing the services in-house on a stand alone basis. On this basis, PB considered the customer services scope change allowances to be reasonable and the most cost-effective option.[680]

PB reviewed ETSA Utilities' proposed scope changes for the allocated cost activity expenditure categories, and concluded that ETSA Utilities' allocated cost scope changes for the next regulatory control period to be prudent and reasonable and proposed no adjustment to the proposed opex.[681] In its review of the largest proposed cost scope expenditure category, information systems, PB considered that the

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677 PB, *Report – ETSA Utilities*, October 2009, pp. 149–156.
678 PB, *Report – ETSA Utilities*, October 2009, p. 157.
679 PB, *Report – ETSA Utilities*, October 2009, p. 155.
680 PB, *Report – ETSA Utilities*, October 2009, p. 159.
681 PB, *Report – ETSA Utilities*, October 2009, pp. 159–162.

estimates provided by ETSA Utilities' staff reflect reasonable opex costs for the proposed works.

AER considerations

The AER acknowledges the difficulty in identifying and forecasting changes in the external environment that will impact on the operations of a DNSP regarding maintaining levels of service, risk and regulatory compliance. The AER notes that ETSA Utilities' proposed changes in scope for the next regulatory control period do not extend beyond 2011–12. ETSA Utilities has anticipated using the pass-through provisions contained in the NER, combined with the additional pass-through events that it has nominated in its proposal, as a vehicle to cater for any unforseen changes in scope.[682]

The AER also reviewed the process that ETSA Utilities used to identify the individual scope changes. The AER notes this approach has been endorsed by PB as a reasonable and pragmatic process that should adequately inform the forecasts of new opex requirements. The AER considers the approach provides for detailed changes in scope to be identified according to the likely drivers, and then the impacts on opex forecasts to be considered. Such an approach is supported by the AER as it provides for detailed consideration of cost impacts of known changes in cost drivers that are likely to impact on ETSA Utilities opex program in the next regulatory control period.

In its review of the opex impact of ETSA Utilities' proposed scope changes, the AER had regard to PB's assessment, and notes PB has concluded all expenditure scope changes are prudent and efficient except those relating to:

- increase in average asset age for the maintenance and repair and emergency opex
- 5 per cent contingency allowance for external costs in vegetation management opex.

As noted in section 8.8.1.2 the AER considers the impact of ETSA Utilities increasing asset age is overstated in ETSA Utilities' modelling. For the reasons noted the AER considers the scope changes proposed by ETSA Utilities in relation to maintenance and repair and emergency response opex do not represent prudent and efficient changes to the base year estimates from which to forecast opex.

The AER also does not consider ETSA Utilities has adequately justified the inclusion of a 5 per cent contingency allowanced factored into vegetation management forecasts. ETSA Utilities has not defined the scope of the work for which this contingency is required and the AER does not consider the scope change proposed by ETSA Utilities represents a prudent and efficient change to base year estimates from which to forecast opex.

ETSA Utilities was asked to remodel its maintenance and repair, emergency response and vegetation management opex to taken into account the revised scope changes required by the AER.[683] ETSA Utilities advised the impact of the adjustment was a

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682 ETSA Utilities, *Regulatory proposal*, July 2009, p. 148.
683 AER, modelling request, 6 November 2009.

reduction of $24 million to maintenance and repair, emergency response and vegetation management opex.

The AER examined KPMG's and SMS Consulting's reviews of ETSA Utilities' commercial contracts with CHED Services for the provision of call centre, FRC and FRC systems support services.[684] Based on these reviews, the AER supports PB's conclusions that outsourcing these services results in lower costs than providing the services in-house on a stand alone basis.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is not satisfied that ETSA Utilities' forecast maintenance and repair, emergency response and vegetation management opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

8.8.1.5 Application of input cost escalators

The AER's detailed consideration and conclusions on ETSA Utilities' input cost escalators, and the methodologies used to derive them, are set out at appendix G. This section addresses the specific application of those proposed cost escalators in ETSA Utilities' opex modelling to establish if their impact has been incorporated in to the opex forecasts appropriately.

ETSA Utilities regulatory proposal

ETSA Utilities engaged BIS Shrapnel to develop real cost escalators for ETSA Utilities' labour costs and contracted services costs[685] and SKM to forecast real cost escalators for ETSA Utilities' material costs, including aluminium, copper, steel, oil and concrete.[686] The approach to calculating cost escalators taken by each of these consultants is discussed in detail in appendix G. The cost escalation rates applied by ETSA Utilities to each category of costs are presented in table 8.4.

ETSA Utilities engaged BIS Shrapnel to prepare forecasts of its real wage growth for the period 2008–09 to 2014–15.[687] BIS Shrapnel prepared a single set of labour cost escalation rates to apply to ETSA Utilities' internal labour forecasts for the period. In developing its labour cost growth escalators, BIS Shrapnel considered macro-economic factors and ETSA Utilities' specific circumstances, including contract terms and historical and future conditions.[688] BIS Shrapnel's forecasts indicate stronger wage growth in the South Australian utilities sector compared to others, due to stronger demand for labour, competition for skilled labour and the impact of planned capex programs planned by network infrastructure businesses in South Australia and

[684] KPMG, *Analysis of call centre outsourcing contract performance benchmarks*, 20 November 2008; KPMG, *Examination of commercial terms in FRC and IT services outsourcing contracts with CHED services*, 10 April 2008; and SMS Consulting, *Review of CHED Services' forecast for FRC systems support*, 25 February 2009.

[685] ETSA Utilities, *Regulatory proposal*, pp. 103-104.

[686] ETSA Utilities, *Regulatory proposal*, p. 105.

[687] BIS Shrapnel, *Outlook for wages, contract services and customer connections expenditure to 2014–15, South Australia*, April 2009.

[688] ETSA Utilities, *Regulatory proposal*, July 2009, p. 103.

nationally.[689] It also noted that the structural initiatives adopted by ETSA Utilities also contribute to wages growth that is higher than the South Australian average.

Table 8.4: ETSA Utilities proposed real cost escalators for opex and capex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Labour costs	–	2.7	3.8	3.5	3.3	3.5	3.3
Services – construction related	–	1.1	1.7	2.5	2.5	1.5	1.9
Services – other outsourced work	–	0.8	0.5	0.8	1.0	1.0	0.8
Materials costs	–	1.7	2.0	1.4	1.4	1.3	1.6

Source: ETSA Utilities, *Regulatory proposal*, July 2009, pp. 103–104 and; ETSA Utilities, *Regulatory proposal*, July 2009, *Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xlsm*, Sheet I-7 Escalations.

The labour cost escalation rates apply to the costs associated with ETSA Utilities' employees and supplementary labour contractor costs incurred in delivering standard control services. The materials cost escalation rates apply to the costs of distribution equipment such as conductor, cable, insulators, circuit breakers and transformers, as well as raw materials for the production of poles, and other items of equipment such as vehicles, plant and tools, and are based on the annual average weighting of each component of the total opex and capex forecasts for the next regulatory control period. The services cost escalation rates apply to the costs of other, predominantly labour-based, contract services costs forecast by ETSA Utilities in order to deliver its services. These services include tree cutting, meter reading and civil works.[690]

ETSA Utilities submitted that the application of these escalation rates within its model was reviewed by SKM and KPMG and assessed as being appropriate.[691]

Based on ETSA Utilities' modelling, the application of these escalators adds around $87 million to the total forecast opex for the next regulatory control period. The impact of ETSA Utilities' proposed real cost escalators on its forecast opex is illustrated in table 8.5.

[689] BIS Shrapnel, *Outlook for wages, contract services and customer connections expenditure to 2014–15, South Australia*, April 2009, p. 2.
[690] ETSA Utilities, *Regulatory proposal*, p. 103.
[691] ETSA Utilities, *Regulatory proposal*, p. 103.

Table 8.5: Impact of real cost escalation on opex forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base opex ($m 2007–08)	181.7	187.5	192.9	199.9	202.9	965.0
Escalation adjustment ($m)	7.4	12.2	17.1	22.4	28.2	87.2
Inflation adjustment ($m)	14.2	14.9	15.7	16.7	17.3	78.9
Total opex (as per proposal, $m 2009–10)	203.3	214.7	225.7	239.0	248.4	1131.1

Sources: ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.1.

Consultant review

The AER engaged PB to provide an independent view on the prudence and efficiency of ETSA Utilities' opex proposal. PB was not required to assess forecast rates of growth in ETSA Utilities' input cost factors, as this analysis was undertaken by the AER. However, PB was required to ensure that forecast changes in input costs have been appropriately reflected in the cost escalation calculations performed by ETSA Utilities in expenditure modelling.

PB also reviewed the reasonableness of the methodology ETSA Utilities used to apply the materials cost escalators, as well as escalators developed for labour, general services and construction services.

As a result of its review, PB concluded that ETSA Utilities' model produces reasonable and accurate results in relation to the application of the real labour, material and services escalators. PB noted that this finding is also supported by the independent reviews undertaken by SKM and KPMG, and their findings.[692]

AER considerations

Materials escalators

PB reviewed the approach applied by SKM to determine appropriate materials cost escalators for ETSA Utilities' capex forecasts, and in particular SKM's approach to the weighting of input commodities within asset classes and the weighting of asset classes within ETSA Utilities' total assets.[693]

The AER has reviewed ETSA Utilities' approach to modelling materials cost escalators within its expenditure forecasts, based on the information provided, including ETSA Utilities' opex and capex models.[694] The AER considers that the approach reasonably reflects the weightings of input commodities and asset classes within ETSA Utilities' forecast expenditure program, and could therefore be expected to realistically reflect the impact of ETSA Utilities' proposed input cost escalators. The AER notes that PB reached the same conclusion based on its own review.

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692 PB, *Report – ETSA Utilities*, October 2009, p. 146.
693 PB, *Report – ETSA Utilities*, October 2009, p. 10.
694 ETSA Utilities, *Regulatory proposal*, July 2009, confidential attachment F.1, SEM Opex model version 7.2, and; confidential attachment E.1, SEM capex model version 7.2.

However, as stated in chapter 7, the AER considers that it is not appropriate for ETSA Utilities to omit escalating real costs in 2008–09, given that its base costs are for 2007–08. ETSA Utilities itself indicated that its approach may understate its real cost increases in 2008–09, but considered it was desirable to retain consistency between the capex and opex models.[695] The AER does not consider that any perceived benefit from modelling consistency outweighs properly reflecting the cost changes that occurred in 2008–09.

The AER therefore requires ETSA Utilities' to apply real cost escalators for 2008–09 in forecasting opex, consistent with its decision regarding capex modelling.

The AER considers that requiring ETSA Utilities to correctly apply real cost escalation to its opex forecasts, which includes accounting for real cost decreases in 2008–09, goes some way to addressing concerns raised in submissions regarding the magnitude of real cost increases in ETSA Utilities' opex forecasts.

Internal labour and contract services

As discussed in detail in appendix G, the AER does not consider ETSA Utilities' labour costs escalators are reasonable because, amongst other things:

- The forecasts developed by BIS Shrapnel in May 2009 are no longer based on the latest available information and expectations, specifically, expectations regarding the macro economic climate which underpin the forecasts

- The internal labour growth forecasts explicitly reflect the impact of ETSA Utilities' own internally determined performance and incentive initiatives, including bonus payments, which the AER considers have not been demonstrated to be efficient by ETSA Utilities

- the forecasts do not appear to accurately consider the actual composition of its internal and contract service labour resources by labour type.

The AER also notes that ETSA Utilities' opex modelling includes a separate line item for forecast employee bonus costs, which are escalated by the proposed labour cost growth rates.[696] The AER considers this is inappropriate and appears to result in some double counting of increased internal labour costs arising from ETSA Utilities' internal structural labour incentive arrangements. The AER has been unable to form a view on this issue for this draft decision. The AER will expect ETSA Utilities revised proposal to provide further information on these proposed bonus costs, and the rationale for applying a real labour cost escalation to those expenditures.

For this draft decision, the AER calculated weighted average real cost escalation rates for ETSA Utilities' internal labour resources, based on the composition of its workforce, by labour type.

[695] ETSA Utilities, response to PB question PB.ETS.EM.67, 20 August 2009.

[696] ETSA Utilities, *Regulatory proposal*, July 2009, confidential attachment F.1 SEM Opex model version 7.2, and; Attachment F.4, Derivation of escalators - detailed description.

Regarding ETSA Utilities' proposed contract services escalators, the has also applied weighted average escalation rates calculated to more accurately reflect the type of labour resources used in these two categories of contract services, as well as accounting for more recent data. The AER's detailed considerations on this issue are set out in appendix G.

The AER's conclusions on real cost escalators to apply to ETSA Utilities' opex forecasts are set out in table 8.6.

AER conclusions

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 ETSA Utilities' cost escalation reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing ETSA Utilities' proposed opex by $38 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.

Table 8.6: AER conclusions on ETSA Utilities real cost escalators for opex (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Labour costs	3.00	2.30	0.99	0.83	1.26	1.79	1.97
Services – construction related	2.10	1.32	–0.26	0.25	1.18	0.75	–0.19
Services – other outsourced work	0.87	1.86	1.05	0.96	1.24	1.76	1.93
Materials costs	–2.14	–5.34	8.27	6.25	1.51	–0.25	–0.53

8.8.1.6 Scale escalation

ETSA Utilities regulatory proposal

ETSA Utilities determined that its opex is linked to certain high-level scale factors affected by scale factors that drive the volume of its operating and maintenance activities. ETSA Utilities identified four key escalators that will increase its scale of operations, and therefore its opex, during the next regulatory control period:[697]

- network growth (proposed $41 million opex impact)
- changes in the volume of capital and maintenance work (proposed $17 million opex impact)
- workforce size (proposed $5.8 million opex impact)
- customer numbers growth (proposed $9.8 million opex impact).

[697] ETSA Utilities, *Regulatory proposal*, July 2009, p. 149.

ETSA Utilities acknowledged that these scale escalators are closely related, but claimed to have taken special care to ensure that double counting has been eliminated.[698] ETSA Utilities reported that engineering consultants SKM concluded that the principle followed by ETSA Utilities of applying escalators to base year opex is a sound and reasonable methodology.[699]

ETSA Utilities also acknowledged that only a small number of its opex categories will grow in direct proportion to the four scale escalators due to economies of scale. ETSA Utilities reported that rather than review each category of opex to determine the extent to which it is driven by, or sensitive to scale escalation, it applied economies of scale factors to broad groups of activities that are driven by similar factors. ETSA Utilities reported that SKM concluded that ETSA Utilities' methodology of applying economies of scale to individual cost categories was reasonable.[700]

Submissions

The ECCSA claimed that, as ETSA Utilities is to operate under a price cap approach, there is implicitly an allowance for growth in revenue as a result of growth in consumption and peak demand and therefore should not be entitled to a scale escalation of its opex as this element is implicitly included by the price cap approach. The ECCSA also challenged the basis of ETSA Utilities' arguments for increases in the four scale escalation factors.[701]

Consultant review

PB reported that it is generally satisfied that network size, work volume, workforce size and customer growth are each factors that will influence opex requirements. PB also reported that ETSA Utilities used a reasonable level of discretion in selecting the activities to which each of the factors applies. PB generally concurred that each factor is applied to each activity in a reasonable manner based on its understanding of the nature of the activities and the intent of the factor, including the use of some multi-factor escalators. PB also considered the economy of scale assumptions applied to the activity groups are reasonable and consistent with those used by similar businesses such as ElectraNet and PowerLink.[702]

PB also stated that as a result of its review of the input references and methodology described in the relevant documents supplied by ETSA Utilities, it noted and accepted as accurate the independent reviews undertaken by SKM and KPMG regarding the application of the growth escalators.[703]

PB identified four specific applications of ETSA Utilities' scale escalations that required adjustments to ETSA Utilities' proposed opex.

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698 ETSA Utilities, *Regulatory proposal*, July 2009, p. 171.
699 ETSA Utilities, *Regulatory proposal*, July 2009, p. 172.
700 ETSA Utilities, *Regulatory proposal*, July 2009, p. 173.
701 ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 40–43.
702 PB, *Report – ETSA Utilities*, October 2009, p. 138.
703 PB, *Report – ETSA Utilities*, October 2009, p. 138.

Network growth scale escalation of opex activities

PB undertook an analysis of the proposed growth of significant ETSA Utilities' assets to attempt to reconcile the macro network escalation of approximately 21 per cent for the period 2008–09 to 2014–15 (a six year average growth rate of 3.2 per cent). PB calculated the simple average year on year annual growth for lines, distribution transformers and installed substation capacity to be 2.7 per cent for the period 2008–09 to 2014–15. PB considered these three asset classes are representative of the ETSA Utilities network asset growth over the period.[704]

PB adjusted the ETSA Utilities opex modelling, with the network growth escalator set to the bottom–up forecast, a reduction in the average network growth from 3.2 per cent to 2.7 per cent. PB recommended a reduction in ETSA Utilities' proposed opex of $9.9 million in the next regulatory control period to account for a network growth factor that better reflects the actual assets to be installed.[705]

Network access, monitoring and control activities

PB stated that ETSA Utilities' network access, monitoring and control opex activities were forecast by escalating the 2008–09 base year expenditures by a multi-factor escalator based on a combination of two separate escalators, specifically the network growth escalator (set at 30 per cent) and the work volume escalator (set at 70 per cent). PB considered that the costs of providing network access, monitoring and control are far more closely aligned to the staff directly employed in this activity rather than the growth in work volume or network growth.

Based on information provided by ETSA Utilities, PB adjusted ETSA Utilities' opex model to only apply the percentage growth relating to the network access, monitoring and control growth in FTEs from 2008–09 through to the end of the next regulatory control period. PB recommended a downwards adjustment in the total network access, monitoring and control opex activity of $2.7 million in the next regulatory control period based on a bottom–up forecast of staff required to undertake this activity. PB noted that the recommended opex for this activity in $2010–11 is $5.8 million, which represents a 10.7 per cent increase compared to the 2009–10 opex. PB assessed this increase as adequate to compensate for the additional work associated with the proposed opex and capex programs.[706]

Emergency response opex

PB was of the view that not all emergency response expenditures are related to external influences. In its review of ETSA Utilities emergency response data, PB discovered that equipment failures accounted for 43 per cent of total emergency response opex. On this basis, PB recommended that the economy of scale factor to be applied to the network growth escalator for emergency response be reduced by 43 per cent to account for the expectation that new assets are not likely to fail consistently and repeatedly in an unplanned manner, but are expected to be exposed to external

[704] PB, *Report – ETSA Utilities*, October 2009, p. 139.
[705] PB, *Report – ETSA Utilities*, October 2009, p. 139.
[706] PB, *Report – ETSA Utilities*, October 2009, pp. 140–142.

influences. PB recommended a reduction in ETSA Utilities' proposed emergency response opex of $8.7 million in the next regulatory control period.[707]

Replacement capex/opex trade off

PB's analysis of the capex/opex trade off for ETSA Utilities is discussed in section 8.8.1.2 of this draft decision. PB recommended a reduction in ETSA Utilities' proposed maintenance and repair opex to account for the asset replacement capex trade off of $0.3m in the next regulatory control period.[708]

AER considerations

The AER assessed PB's analysis of the reviews undertaken by SKM and KPMG in regards to ETSA Utilities' application of its growth escalators and considers that the reviews by SKM and KPMG are thorough and reliable.

The AER has considered the ECCSA's claim that an opex scale escalation element is implicitly included in ETSA Utilities' price cap for the next regulatory control period. Under the NER, the AER's assessment of a DNSP's costs is conducted using a building blocks assessment, regardless of the particular form of control. This assessment determines a DNSP's annual revenue requirements, which reflect both expected changes in unit costs and the scale of the DNSPs operations. The particular form of control will determine how the annual revenue requirements may be recovered by the DNSP. Under a weighted average price cap, a DNSP is exposed to the risk that it may not achieve its annual revenue requirement if demand is greater or less than expected during the building blocks assessment. The AER therefore does not consider that the ECCSA has sufficiently demonstrated that an opex scale escalation element is implicitly included in ETSA Utilities' price cap for the next regulatory control period.

The AER considers it reasonable that ETSA Utilities apply scale factors to account for opex categories that will grow in proportion to the four scale factors identified by ETSA Utilities. The AER also considers the approach taken by ETSA Utilities in applying scale escalation factors to broad groups of activities that are driven by similar factors is generally reasonable and largely consistent with the approach accepted by the AER in its draft ElectraNet determination.[709] After reviewing the scale escalation factors proposed by ETSA Utilities, the AER considers that the economy of scale assumptions applied to the activity groups by ETSA Utilities are generally reasonable and consistent with those used by similar businesses.

Network growth escalator

The AER notes ETSA Utilities proposed to use a network growth escalator that applies an average growth rate of 3.2 per cent in the period 2008–09 to 2014–15. However, the actual growth rate calculated for lines, distribution transformers and installed substation capacity, as estimated by PB, is only 2.7 per cent for that period.

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707 PB, *Report – ETSA Utilities*, October 2009, p. 143.
708 PB, *Report – ETSA Utilities*, October 2009, p. 145.
709 AER, *Draft decision – ElectraNet transmission determination 2008–09 to 2012–13*, November 2007.

The AER considers that the network growth factor applied by ETSA Utilities is higher than necessary to reflect the efficient costs of a prudent operator. The AER considers that the network growth rate estimated by PB provides a reasonable basis for the over estimation of costs arising from the application of ETSA Utilities' network growth escalator. The AER considers that ETSA Utilities' proposed total opex should be reduced to account for the adjustment to the network growth escalator.

Network access, monitoring and control opex

The AER notes that ETSA Utilities applied a multi-factor escalator based on its network growth escalator and work volume escalator to the forecasts for network access, monitoring and control opex. The AER considers network access, monitoring and control capability tends to increase in discreet and step changes, and is therefore more closely aligned to the staff employed in this activity rather than the growth in work volume or network growth.

The AER considers that the nature of activities associated with network access, monitoring and control are generally labour based, and as such are more likely to increase due to staff increments, rather than in direct proportion to network growth.

For this reason the AER considers the escalation factor applied by ETSA Utilities, based on network growth and work volume, is higher than necessary to reflect the efficient costs of a prudent operator. The AER considers that the methodology recommended by PB, of escalating this opex category by increases in full time equivalent (FTE) staff numbers provides a reasonable estimation of the required costs cost escalation for network access, monitoring and control.

Emergency response opex

The AER notes that 43 per cent of ETSA Utilities' emergency response opex arises due to asset failure arising from poor condition or maintenance, rather than from external factors such as weather related damage. In such circumstances asset replacement capex and preventative and corrective maintenance should directly reduce the level of emergency response opex, as the new or refurbished and maintained assets are considerably less likely to fail.

As such the AER considers that ETSA Utilities has underestimated the likely economies of scale that will impact on the required level of emergency response opex. The AER considers that PB's revised economies of scale measure, estimated by reducing the economies of scale factor for emergency response opex by 43 per cent to 0.54 provides a reasonable estimation of an economy of scale factor.

Replacement capex/opex trade off

As discussed in section 8.8.1.2 of this draft decision, the AER has required ETSA Utilities' to remodel its proposed maintenance and repair opex to account for the asset replacement capex trade off in the next regulatory control period.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is not satisfied that ETSA Utilities' forecast network growth escalator reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is not satisfied that ETSA Utilities' forecast network access, monitoring and control, and emergency response opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

ETSA Utilities was asked to remodel its forecast of opex to incorporate the adjustments to the network growth escalator, maintenance and repair, network access, monitoring and control, and emergency response opex.[710] ETSA Utilities advised the impact of these adjustment was a reduction of $16 million to maintenance and repair, network access, monitoring and control, and emergency response opex.

8.8.1.7 Network operations

Network operations opex is related to those activities which enable the effective and efficient operation of the distribution network including network access, network asset management, network telephony and regulatory compliance.

ETSA Utilities regulatory proposal

Table 8.7 shows a breakdown of ETSA Utilities' proposed network operations costs for the next regulatory control period.

Table 8.7: ETSA Utilities' forecast network operations expenditure ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Distribution licence fee	3.6	3.6	3.6	3.6	3.6	18.1
Network access, monitoring and control	6.9	7.4	7.6	7.9	8.3	38.0
Network asset management	5.1	5.4	5.6	5.8	6.1	28.0
Network asset systems and information	3.8	4.1	4.2	4.3	4.5	20.9
Network telephony	6.7	7.0	7.4	8.0	8.5	37.6
Regulatory compliance	2.4	2.5	2.6	2.7	2.8	13.1
Total network operations	28.5	30.0	31.1	32.4	33.8	155.7

Source: ETSA Utilities, RIN opex pro forma 2.2.2.
Note: Totals may not add due to rounding.

Proposed network operations opex in the next regulatory control period is $156 million, compared with an estimated $99 million in the current regulatory control period, an increase of 58 per cent. Network operations opex accounts for approximately 14 per cent of ETSA Utilities' proposed opex in the next regulatory control period.

[710] AER, modelling request, 6 November 2009.

Consultant review

PB reviewed ETSA Utilities' asset management documentation and considered that ETSA Utilities' forecast opex is based on prudent and orthodox asset management principles, processes and procedures. PB commented that ETSA Utilities' approach to system-wide time-based preventative maintenance cycles, coupled with clear drivers to capture asset performance knowledge using leading indicators, should provide ETSA Utilities with a reasonable framework to move to a more efficient and advanced condition-based style of asset management in the future. PB also noted that its views in this area are to a large extent consistent with, as well as being informed by, the detailed independent reviews of ETSA Utilities asset management documentation undertaken by SKM and Maunsell Australia (Maunsell) over the last two years.[711]

PB reviewed the forecasting methodology for network operations opex and concluded that the process is reasonable and transparent.[712] PB considered that aside from a downwards adjustment of $2.7 million in the total network access, monitoring and control opex activity in relation to the application of growth escalators, ETSA Utilities proposed network operations opex is prudent and efficient. PB came to this view after its review of ETSA Utilities' forecasting methodology, including the development of the base-year expenditure, the proposed scope changes and the application of the input cost escalators for this category.[713] Details of PB's review of the impact of the scope changes and scale escalation factors proposed by ETSA Utilities on its forecast network operations opex are presented in sections 8.8.1.4 and 8.8.1.6 of this draft decision respectively.

AER considerations

The AER notes that the forecast network operations costs in the next regulatory control period will be significantly higher than in the current regulatory control period. The AER notes that PB concluded that all of the network operations scope change allowances to be prudent and efficient. In its analysis, PB reviewed proposed network operations opex increases in ETSA Utilities' asset strategy and planning, maintenance planning and network telephony. The AER also reviewed the activities included in this expenditure category and agrees that these are likely to be impacted by changes in scope, scale escalation and input cost escalators, leading to an increase in network operations opex faced by ETSA Utilities in the next regulatory control period.

Based on PB's advice and its own analysis of scale escalation and scope change factors proposed by ETSA Utilities, the AER considers that with the exception of one adjustment, ETSA Utilities reflects the efficient costs that a prudent DNSP in the circumstances of ETSA Utilities would require to achieve the opex objectives.

The AER requested ETSA Utilities remodel its network operating forecast to reflect the escalation factor adjustment noted in section 8.8.1.5.[714] Based on this modelling,

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711 PB, *Report – ETSA Utilities*, October 2009, Attachment E.12, SKM Asset Management Policy Review, April 2008, attachment E.13, Maunsell AMP Review, November 2008 and p. 120.

712 PB, *Report – ETSA Utilities*, October 2009, p. 136.

713 PB, *Report – ETSA Utilities*, October 2009, p. 148.

714 AER, modelling request, 6 November 2009.

ETSA Utilities provided an updated network operating forecast of a downward adjustment of $0.01 million.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is not satisfied that ETSA Utilities' forecast network operations opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing ETSA Utilities' proposed network operations opex by $0.01 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

8.8.1.8 Network maintenance

Network maintenance opex is related to planned or programmed maintenance carried out to reduce the probability of failure or performance degradation of a network asset. It also includes emergency response opex and vegetation management, demand management and network insurance opex.

ETSA Utilities regulatory proposal

Table 8.8 shows a breakdown of ETSA Utilities' proposed network maintenance costs for the next regulatory control period.

Table 8.8: ETSA Utilities' forecast network maintenance expenditure ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Inspections	10.0	10.7	11.3	11.8	12.4	56.2
Maintenance and repair	14.5	15.7	16.9	18.2	19.7	84.9
Substation property maintenance	3.8	4.0	4.2	4.5	4.7	21.2
Vegetation management	21.0	20.3	20.7	21.6	20.9	104.4
Emergency response	29.8	32.4	35.1	37.9	41.0	176.1
Demand management	0.7	0.7	0.7	0.7	0.8	3.6
Demand management innovation fund	0.6	0.6	0.6	0.6	0.6	3.0
Guaranteed service level payments	0.9	0.9	0.9	0.9	0.9	4.3
Network insurance	2.3	2.5	2.7	2.9	3.0	13.2
Total network maintenance	83.5	87.7	93.0	99.0	103.9	467.1

Source: ETSA Utilities, RIN opex pro forma 2.2.2.
Note: Totals may not add due to rounding.

Proposed network maintenance opex in the next regulatory control period is $467 million, compared with an estimated $305 million in the current regulatory control period, an increase of 53 per cent. Network maintenance opex accounts for approximately 41 per cent of ETSA Utilities' proposed opex.

Submissions

Business SA supported the condition monitoring based approach to determine which ageing assets to replace or upgrade, and argued such an approach should minimise costs faced by ETSA Utilities.[715]

Origin raised concerns about whether ETSA Utilities' condition monitoring strategies would be fully implemented by the start of the next regulatory control period.[716]

Consultant review

PB reviewed the forecasting methodology for network maintenance opex and concluded that the process is reasonable and transparent and escalation factors have been applied appropriately.[717] PB's review of the impact of the scope changes and scale escalation factors proposed by ETSA Utilities on its forecast network maintenance opex are presented in sections 8.8.1.4 and 8.8.1.6 of this draft decision respectively. PB's review of the asset replacement capex/opex trade off also impacted on its recommended network maintenance opex and is presented in section 8.8.1.2 of this report.

Although PB assessed the increased vegetation management allowance proposed by ETSA Utilities as reasonable and prudent given its current non–compliance and potential safety issues, it considered the 5 per cent contingency allowance for external costs was not prudent or efficient as the scope of work was not specified by ETSA Utilities. On this basis, PB recommended that the proposed contingency allowance of $4.8 million in the next regulatory control period be removed from the vegetation management expenditure category.[718]

On the basis of its review of ETSA Utilities' proposed network maintenance opex, PB recommended the following reductions:[719]

- emergency response expenditure of $22 million ($8.7 million for scale escalation and $13.3 million for scope changes)
- maintenance and repair expenditure of $6.5 million (including $0.3 million for preventative maintenance for the asset replacement capex/opex trade off)
- vegetation management expenditure of $4.8 million.

AER considerations

The AER notes that the forecast network maintenance costs in the next regulatory control period will be significantly higher than the current regulatory control period.

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715 Business SA, *Submission to the AER*, August 2009, p. 6.
716 Origin, *ETSA Utilities*, August 2009, p. 7.
717 PB, *Report – ETSA Utilities*, October 2009, p. 148.
718 PB, *Report – ETSA Utilities*, October 2009, p. 155.
719 PB, *Report – ETSA Utilities*, October 2009, pp. 142, 144 and 157.

The AER has reviewed PB's analysis of ETSA Utilities' proposed scope changes in regards to network maintenance related activities and notes that PB concluded that the proposed network maintenance expenditure increases in inspections, maintenance and repair, emergency response, DMIA and network insurance to be prudent and efficient. PB also determined that the proposed increases in maintenance and repair and emergency response due to increasing asset age were not substantiated and are therefore not prudent and efficient scope changes and should be removed from the network maintenance opex forecasts. PB also considered that the 5 per cent contingency allowance for external costs for vegetation management as not prudent or efficient as the scope of work was not specified by ETSA Utilities.

The AER reviewed the proposed network maintenance opex and agrees that these are likely to be impacted by changes in scope, scale escalation and input cost escalators, leading to an increase in network maintenance expenditure faced by ETSA Utilities in the next regulatory control period. Based on PB's advice and its own analysis of scale escalation and scope change factors proposed by ETSA Utilities, the AER considers that with the exceptions of the adjustments to preventative maintenance, emergency response, maintenance and repair, and vegetation management, ETSA Utilities opex forecast reasonably reflects the efficient costs that a prudent DNSP in the circumstances of ETSA Utilities would require to achieve the opex objectives.

Guaranteed Service Level payments

ETSA Utilities is required to make Guaranteed Service Level (GSL) payments to customers that receive a service level below the thresholds established under the GSL scheme administered by ESCOSA.[720] ESCOSA made an opex allowance of approximately $1.2 million for GSL payments in the current regulatory control period in recognition of ETSA Utilities' obligation to make these payments.[721]

The AER has reviewed ETSA Utilities' forecast of GSL payments and notes that such 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 GSL payments, under certain circumstances, may be considered regulatory payments in accordance with section 2E of the NEL. For example, in the circumstances where making a GSL payment for breach of a distribution service standard is more efficient than making the necessary investments to ensure compliance with the distribution service standard, the GSL payment appears to satisfy paragraph (b) of section 2E of the NEL. Where a GSL payment is made for a breach of a service standard that occurs due to business mismanagement rather than efficient planning considerations, that payment is less likely to satisfy the NEL definition of a regulatory payment.

The AER accepts that a prudent and efficient network service provider may incur GSL payments in order to meet efficient planning goals and that such payments represent a regulatory obligation imposed on ETSA Utilities. As such, the AER

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[720] ESCOSA, *Electricity Distribution Code*, clause 5.3 of Part B

[721] ESCOSA, *ETSA Utilities 2005–2010 Electricity Distribution Price Determination, Part A,* April 2005, p. 100.

considers that it must provide a reasonable opportunity for ETSA Utilities to recover the efficient costs of satisfying such obligations under clause 7A(2)(b) of the NEL.

The AER also recognises section 7A(3) of the NEL which indicates that network service providers should be given effective incentives to promote economic efficiency. GSL payments above the efficient level are costs that the AER considers should be incurred by shareholders rather than customers.

The AER notes that the reliability based GSL payments (that is excluding timeliness for customer appointments, connection of a new supply address and street light repair), were approximately $1.8 million in 2005–06, $0.7 million in 2006/07 and $0.4 million in 2007–08.[722] The AER considers that ETSA Utilities forecast of GSL payments is consistent with its historical levels of GSL payments.

Network insurance

ETSA Utilities submitted that it commissioned AON Risk Services Australia Ltd (AON Risk Services) to provide an estimate of its insurance costs for the next regulatory control period. ETSA Utilities stated that AON Risk Services' estimate gave consideration to:[723]

- broad insurance industry trends
- the insurance industry's assessment of risks pertaining to electricity distribution operations in high bushfire risk areas
- ETSA Utilities' current circumstances and relationship with insurers
- trends in key internal factors (insured asset values, revenue, workforce size and wages).

ETSA Utilities also submit that AON Risk Services' estimate gives consideration to scale factors, and hence ETSA Utilities has not applied any additional scale escalation to its forecast for insurance premiums.[724] ETSA Utilities' 2008–09 insurance costs were used as a base from which AON Risk Services forecast network insurance costs for the next regulatory control period.[725]

In its review of AON Risk Services' network insurance premium forecasts, PB submit that given the transparent approach adopted by AON Risk Services and the nature of the insurance classes included in ETSA Utilities' 2008–09 insurance costs and the potential impact of bushfire and environmental factors outlined, PB was satisfied that ETSA Utilities' forecast network insurance allowances are prudent and efficient. PB also noted that ETSA Utilities had ensured that only the appropriate proportion of the

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722 ESCOSA, *South Australian Electricity Distribution Services Standards: 2010–2015 Final Decision*, November 2008, p. 76.

723 ETSA Utilities, *Regulatory proposal*, July 2009, p. 162, attachment F.8, AON: Forecast of ETSA Utilities' insurance costs, February 2009, confidential.

724 ETSA Utilities, *Regulatory proposal*, July 2009, p. 162.

725 ETSA Utilities, *Regulatory proposal*, July 2009, attachment F.8, AON: Forecast of ETSA Utilities' insurance costs, February 2009, confidential.

insurance premium relevant to standard control services was included by ETSA Utilities in its forecast network insurance allowance, consistent with its CAM.[726]

The AER considers it appropriate that ETSA Utilities commissioned AON Risk Services to provide an estimate of its insurance liabilities for the next regulatory control period. The AER also considers that the approach undertaken by AON Risk Services is transparent and reasonable and agrees with PB's assessment that ETSA Utilities' forecast network insurance allowances are prudent and efficient. The AER notes that AON Risk Services concluded that ETSA Utilities are likely to experience increased insurance costs as a result of both business growth and rate increases caused by general market trends.[727]

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is satisfied that ETSA Utilities' network insurance opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is not satisfied that ETSA Utilities' forecast emergency response, maintenance and repair and vegetation management opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing ETSA Utilities' proposed network maintenance opex by $40.5 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

8.8.1.9 Customer service

ETSA Utilities' customer services opex is related to call centre activities, meter reading and regulated activities arising from the introduction of FRC.

ETSA Utilities regulatory proposal

Table 8.9 shows a breakdown of ETSA Utilities' proposed customer services costs for the next regulatory control period.

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[726] PB, *Report – ETSA Utilities*, October 2009, p. 156.

[727] ETSA Utilities, *Regulatory proposal*, July 2009, attachment F.8, AON: Forecast of ETSA Utilities' insurance costs, February 2009, confidential.

Table 8.9: ETSA Utilities' forecast customer services expenditure ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Meter reading	3.6	3.7	3.8	3.8	3.9	18.8
Call centre	2.3	2.3	2.4	2.4	2.5	11.9
Full retail contestability	14.1	14.4	14.7	15.1	15.4	73.6
Other customer services	4.9	5.1	5.2	5.4	5.6	26.2
Total customer services	24.8	25.4	26.1	26.7	27.4	130.4

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN pro forma 2.2.2.
Note: Totals may not add up due to rounding.

ETSA Utilities' proposed customer services opex in the next regulatory control period is $130 million, compared with an estimated $101 million in the current regulatory control period, an increase of 29 per cent. Customer services opex accounts for approximately 12 per cent of ETSA Utilities' proposed opex.

Consultant review

PB reviewed the forecasting methodology for customer services opex and concluded that the process is reasonable and transparent and escalation factors have been applied appropriately.[728] Discussion of PB's review of the scope changes and scale escalation factors proposed by ETSA Utilities in its forecast customer services opex are presented in sections 8.8.1.4 and 8.8.1.6 of this report respectively.

PB considered the forecast opex for customer services is prudent and efficient and has not recommended any adjustment to ETSA Utilities' proposed customer services opex for the next regulatory control period.

AER considerations

The AER notes that although the forecast customer services costs in the next regulatory control period will be significantly higher than the current regulatory control period, the proposed increase is substantially less than the proposed increases in the network operating and network maintenance opex. The customer services expenditure category responsible for almost two-thirds of the increase in forecast customer services costs is FRC costs, which PB have assessed to be reasonable and cost effective.

The AER has reviewed PB's analysis of ETSA Utilities' proposed scope change in regards to customer services related activities and notes that PB concluded that the customer services scope change allowances to be reasonable and cost-effective. The AER also reviewed the activities included in this expenditure category and agrees that these are likely to be impacted by changes in scope, scale escalation and input cost escalators, leading to an increase in customer services expenditure faced by ETSA Utilities in the next regulatory control period.

Based on PB's advice and its analysis of scale escalation and scope change factors proposed by ETSA Utilities, the AER considers that ETSA Utilities' customer

[728] PB, *Report – ETSA Utilities*, October 2009, p. 157.

services expenditure reflects the efficient costs that a prudent DNSP in the circumstances of ETSA Utilities would require to achieve the opex objective.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is satisfied that ETSA Utilities' customer services opex (excluding input cost escalation) reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

8.8.1.10 Allocated costs

Allocated costs are all shared business overheads, including the costs associated with the chief executive officer, planning and audit, communications, regulation and company secretary, human resources and training, property, information systems and risk management.

ETSA Utilities regulatory proposal

Table 8.10 shows a breakdown of ETSA Utilities' proposed allocated costs for the next regulatory control period.

Table 8.10: ETSA Utilities' forecast allocated costs expenditure ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
CEO, planning and audit	2.3	2.4	2.4	2.5	2.6	12.1
Communications	2.5	2.6	2.6	2.6	2.7	13.0
Regulation and company secretary	2.1	2.2	2.5	3.7	3.8	14.2
Finance	9.9	10.4	10.8	11.3	11.8	54.1
HR and training	8.0	8.5	8.9	9.3	9.6	44.2
Property	6.9	7.2	7.4	7.9	8.1	37.4
Information systems	9.0	11.2	12.4	13.9	13.9	60.3
Risk management	9.3	10.0	10.6	11.1	11.4	52.3
ETSA Utilities proposal	49.9	54.3	57.5	62.2	63.9	287.8

Source: ETSA Utilities, RIN opex pro forma 2.2.2.
Note: Totals may not add due to rounding.

Proposed allocated costs opex in the next regulatory control period are $288 million, compared with an estimated $163 million in the current regulatory control period, an increase of 77 per cent. Allocated costs opex accounts for approximately 25 per cent of ETSA Utilities' proposed opex.

Under ETSA Utilities' approved cost allocation methodology, all allocated costs are expensed.

Consultant review

PB reviewed the forecasting methodology for allocated costs opex and concluded that the process is reasonable and transparent and escalation factors have been applied appropriately.[729] Discussion of PB's review of the scope changes and scale escalation factors proposed by ETSA Utilities in its forecast allocated costs opex are presented in sections 8.8.1.4 and 8.8.1.6 of this report respectively.

PB has reviewed ETSA Utilities' proposed allocated cost expenditure category:

- PB assessed the factors that influence the increase in information systems opex to be additional staff, an increased organisational reliance on IT based information and systems, increased reliance on mobile computing, an increasing number of operating sites to support, an increased level of required software upgrades, equipment renewals and major systems renewals, as well as additional costs incurred to support the new Network Operations Centre. PB assessed these proposed information system costs to reflect reasonable opex costs.

- As a consequence of the South Australian Government's imposition of a change in ETSA Utilities' land tax obligations commencing 1 July 2010, ETSA Utilities has included an additional $2.1 million for additional land tax in each year, which PB considers to be prudent and efficient.

- PB considered the increased opex allowance for running the Davenport training centre to be prudent and reasonable given that it will support the recruitment of staff, the initial purchase of materials needed for the delivery of training services and contract developments with external service providers.

- PB considered the variations proposed to offset the impact of finance adjustments embedded in the base year are reasonable as they account for one off adjustments related to the removal of superannuation provisions for proposed legislative and operational changes to the defined benefits scheme, which have not eventuated, and an adjustment to the long service leave provision in line with actuarial advice.

- The allowances to undertake focussed customer surveys and the initiatives to improve customer outage notifications during emergencies were considered by PB to be prudent and reasonable.[730]

PB considered the forecast opex for allocated costs is prudent and efficient and has not recommended any adjustment to ETSA Utilities' proposed customer services opex for the next regulatory control period.

AER considerations

The AER notes that the forecast allocated costs in the next regulatory control period will be significantly higher than the current regulatory control period.

[729] PB, *Report – ETSA Utilities*, October 2009, p. 160.
[730] PB, *Report – ETSA Utilities*, October 2009, pp. 160–162.

The AER reviewed the activities included in this expenditure category and agrees that these are likely to be impacted by changes in scope, scale escalation and input cost escalators, leading to an increase in allocated costs expenditure faced by ETSA Utilities in the next regulatory control period. The AER notes that the allocated cost expenditure categories responsible for the majority of the proposed increase in allocated costs are information systems, property, human resources and training and finance adjustments.

Communications opex

ETSA Utilities proposed a total of $13 million in communications expenditure for the next regulatory control period. The AER sought further information from ETSA Utilities regarding the nature of the costs within this expenditure category. ETSA Utilities advised that the following costs are represented in this forecast expenditure category:[731]

- preparation and distribution of internal communications
- management of ETSA Utilities' website
- preparation and distribution of ETSA Utilities' Annual Report
- sponsorships, advertising and marketing costs.

ETSA Utilities' submitted that approximately 87 per cent of these costs are allocated to its standard control services, with the remaining 13 per cent allocated to its negotiated services. This allocation is in accordance with ETSA Utilities approved CAM.

ETSA Utilities also advised that, given the elevated profile of works proposed for the next regulatory control period, it anticipates an increase in the advertisements and other communications requirements relating to its operational activities. To reflect this, ETSA Utilities applied its work volume escalator to its communications opex forecast, with an economy of scale factor of 90 per cent.[732]

The AER considers that the majority of these proposed expenditure items in this category are reasonable, however, it does have concerns regarding ETSA Utilities' proposed sponsorship, advertising and marketing costs.

In response to further enquiries, ETSA Utilities submitted that, during the 2008–09, it incurred expenditures relating to sponsorship arrangements with Country Arts SA, SA Museum, Netball SA and a tertiary education scholarship program, at a total cost of $0.51 million. It stated that these sponsorship activities are undertaken to meet its corporate responsibilities.[733] The AER also understands that ETSA Utilities is engaged in sponsorship of the following entities and events, among others:[734]

[731] ETSA Utilities, email response to AER.EU.34. 15 October 2009. pp. 3–4.
[732] ETSA Utilities, email response to AER.EU.34. 15 October 2009. p. 4
[733] ETSA Utilities, email response to AER.EU.34. 15 October 2009. p. 3.
[734] ETSA Utilities, Website, <http://www.etsautilities.com.au/centric/about_etsa/community_environment/sponsorship.jsp.>, Accessed on 30 October 2009.

- ETSA Park (stadium)
- Adelaide Symphony Orchestra
- Adelaide International Film Festival
- ETSA Contax netball team
- Adelaide Zoo Giant Panda project.

ETSA Utilities submitted that its forecast sponsorship opex for the next regulatory period is $0.51 million per year, consistent with the 2008–09 base year expenditure.

The AER notes that ETSA Utilities considers its sponsorship program is aligned with its strategic intent, which it stated is 'to be a financially successful and respected provider of electricity distribution and associated services'. ETSA Utilities further notes that:[735]

> Our sponsorships must reflect the significant role ETSA Utilities plays in South Australia, and our desire to provide excellent service to our customers and the community.

ETSA Utilities notes that it supports community groups, projects, events and programs, which are ethical and socially responsible, focussed on the community, health and sport, arts and culture and energy.[736] ETSA Utilities also submitted that these activities are undertaken to meet its corporate responsibilities.

The AER considers that some level of community engagement expenditure directly related to the safe provision of electricity distribution services to the public may be reasonably attributed to standard control services, for example, advertising campaigns that promote public safety awareness and notification of proposed works which may impact on its customers' use of the distribution network. The AER considers that such expenditure is likely to be consistent with the opex objectives, in particular, clauses 6.5.6(2), (3) and (4) of the NER.

The AER notes that ETSA Utilities considers its sponsorship activities are undertaken in order to meet its corporate responsibilities, and strategic intent. However, it is unclear how these responsibilities and internal strategic goals reflect, and align with, the opex objectives of the NER.

The AER does not generally consider that sponsorship activities represent costs that are reasonably required to comply with the opex objectives. Sponsorships are generally undertaken to increase brand awareness, demonstrate community support, and potentially for associated tax benefits. Such activities may provide a benefit to the community or environment, however, they do not appear to be relevant to the

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735 ETSA Utilities, *Regulatory proposal*, July 2009, p. 33, and; ETSA Utilities, Website, <http://www.etsautilities.com.au/centric/about_etsa/community_environment/sponsorship.jsp.>, Accessed on 30 October 2009.

736 ETSA Utilities, *Sponsorship guidelines*, available at: <http://www.etsautilities.com.au/centric/about_etsa/community_environment/sponsorship.jsp>, Accessed on 29 October 2009.

provision of standard control services, nor do they reflect the opex objectives. To this end, the AER would expect these costs to be borne by ETSA Utilities' shareholders, rather than recovered from customers through regulated monopoly distribution charges.

The AER notes that this issue was considered by ESCOSA during the 2005–10 electricity distribution price determination.[737] In its expenditure submission to ESCOSA for the current regulatory control period, ETSA Utilities included some forecast expenditures to undertake a range of community engagement programs including sponsorships, 'cause related' marketing and scholarships, among others.[738] ETSA Utilities however noted that the net benefit to the community, or willingness to pay, in many of these areas was inconclusive and it considered that significant additional expenditure on non–core obligations is unlikely to be supported by the general community.[739]

ESCOSA considered the inclusion of these sponsorship costs in the regulated forecast allowance was inappropriate. ESCOSA stated:[740]

> The Commission is also of the view that, during the 2005–10 regulatory period, ETSA Utilities should not be able to fund community projects through the use of prescribed distribution revenue. The Commission has had regard to the many submissions provided on this issue in reaching this decision. While the Commission acknowledges that support of community projects is a laudable corporate objective, it is of the opinion that it is not appropriate for South Australian distribution customers to be funding these projects.

In light of ESCOSA's explicit decision to reject the proposed sponsorship expenditures, the AER has concerns regarding ETSA Utilities' proposal to include these costs in its 2008–09 base year expenditure for communications opex, as noted above. The AER considers that these costs represent costs that were explicitly excluded from the efficient regulated allowance for the current regulatory control period set by ESCOSA. It follows then that, the costs of any such activities incurred during the current regulatory control period have been effectively absorbed by ETSA Utilities, or funded by revenue from sources other than its prescribed distribution services, and should not be included in the forecasting base year expenditures for the next regulatory control period.

The AER does not consider that ETSA Utilities has demonstrated its proposed sponsorship and community engagement expenditure is required to achieve the opex objectives, or outlined how this expenditure is relevant to the provision of standard control services. The AER considers that the decision to pursue these sponsorship activities is an internal response to meeting ETSA Utilities' own strategic goals and expectations, rather than the direct needs and expectations of customers receiving electricity distribution services. The AER expects that, if ETSA Utilities considers its community engagement and sponsorship activities are an important and appropriate

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737 ESCOSA, *Draft 2005–10 electricity distribution price determination. Part A – Statement of reasons*, December 2004.

738 ETSA Utilities, *Expenditure submission 2005/06–2009/10*, p. 70.

739 ETSA Utilities, *Expenditure submission 2005/06–2009/10*, pp. 65 and 67.

740 ESCOSA, *Draft 2005–10 electricity distribution price determination. Part A – Statement of reasons*, December 2004, p. 123

response to meeting its internal corporate objectives, it should continue to fund these activities through retained profits or unregulated revenues only.

The AER is not satisfied that ETSA Utilities' forecast communications expenditure is efficient and prudent expenditure. The AER asked ETSA Utilities' to remodel its forecast communications opex to remove all costs associated with sponsorships and community engagement projects, other than those reasonably required to deliver key messages and education to customers regarding the distribution network. Based on this modelling, ETSA Utilities removed an amount of $3.2 million from its forecast opex allowance.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is not satisfied that ETSA Utilities' forecast allocated costs opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing ETSA Utilities' proposed allocated costs by $3.2 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

8.8.1.11 Demand management

Clause 6.5.6(a)(1) of the NER requires that a DNSP's total forecast opex must satisfy the opex objective to meet, or manage, the expected demand for standard control services. Under clause 6.5.6(e)(10) of the NER, the AER must have regard to the extent to which a DNSP has considered, and made provision for, efficient non–network alternatives when assessing a DNSP's forecast opex proposal. Further, clause 6.6.3(a) of the NER provides for the AER to develop an incentive scheme for ETSA Utilities to implement efficient non–network alternatives or to manage the expected demand for standard control services in some other way.[741]

ETSA Utilities regulatory proposal

ETSA Utilities submitted that during the current regulatory control period it has undertaken various demand management pilot programs, the most notable being a direct load control program whereby ETSA Utilities can directly manage the load of residential customers.[742] ETSA Utilities stated the opex associated with demand management that undertaking these pilot programs has contributed to unusually high operating expenditure during the 2008–09 base year.[743]

ETSA Utilities' submission included opex associated with demand management that is in addition to that associated with the AER's DMIS. ETSA Utilities stated this expenditure is required to ensure that ETSA Utilities can continue to give consideration to non–network solutions in addressing capacity constraints.[744] [745]

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741 Further discussion and details of the AER's Demand Management Incentive Scheme for ETSA Utilities is presented in section 14 of this draft decision.

742 ETSA Utilities, *Regulatory proposal*, July 2009, p. 157.

743 ETSA Utilities, *Regulatory proposal*, July 2009, p. 157.

744 ETSA Utilities, *Regulatory proposal*, July 2009, p. 157.

745 Details of the Demand Management Incentive Scheme are in chapter 14 of this draft decision.

ETSA Utilities submitted that, in particular, expenditure is required to ensure ongoing compliance with ESCOSA's Electricity Industry Guideline 12 which imposes specific requirements on ETSA Utilities when undertaking significant expansion of its network.[746]

ETSA Utilities' submission included the following demand management opportunities that ETSA Utilities may pursue during the course of the next regulatory control period:[747]

- power factor correction
- Peakbreaker+
- implementation of Peakbreaker+.

Table 8.11 shows ETSA Utilities' forecast demand management expenditure for the next regulatory control period.

Table 8.11: ETSA Utilities' forecast demand management expenditure ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Demand management	0.7	0.7	0.7	0.7	0.8	3.6

Source: ETSA Utilities, *Regulatory* proposal, July 2009, RIN opex pro forma 2.2.2.

Submissions

The EUAA endorsed demand management as an option that should be seriously considered in meeting energy and peak demand growth, wherever it meets cost-benefit criteria. Also, the EUAA submitted that the AER's approach to demand management does not provide DNSPs with sufficient incentives to pursue demand management and does not sufficiently prioritise demand management issues.[748]

UnitingCare Wesley expressed its concern with the apparent lack of demand management projects in ETSA Utilities' proposal, particularly given the various trials undertaken in the current regulatory control period and that customers have already contributed to demand management strategies for ETSA Utilities. It proposed that the AER set demand management targets that should be discussed with key stakeholders.[749]

Business SA acknowledged that while the AER may not have the authority to enforce greater demand side management activities on ETSA Utilities, it urged the AER review the scope for reducing ETSA Utilities' capital expenditures on the network by

746 ETSA Utilities, *Regulatory proposal*, July 2009, p. 157.
747 ETSA Utilities, *Regulatory proposal*, July 2009, p. 200.
748 EUAA, *Submission to the* AER, 28 August 2009, p. 11.
749 UCW, *Distribution price review for South* Australia, p. 14.

substituting increased demand management projects in their place. Business SA also submitted two options for encouraging demand management initiatives:[750]

- increasing the DMIS allowance of $3 million, and
- consideration of partnerships between ETSA Utilities and companies interested in demand management.[751]

SACOSS submitted that the regulatory approach appears to absolve ETSA Utilities from any material responsibilities to manage South Australia's growing peak demand and worsening network utilisation and therefore fails the national electricity objective as the long term interests of consumers will not be met under ETSA Utilities' proposal. SACOSS stated that ETSA Utilities is ready in the next regulatory control period to go beyond trials and deliver significant, broad based peak demand reduction solutions.[752]

The ECCSA submitted that if the AER determines than an enhanced demand management program is appropriate, then the additional cost would justify a step change.[753]

Consultant report

PB reviewed ETSA Utilities' proposed demand management opex and noted that a number of non–network solutions have been incorporated into ETSA Utilities' projected capital and operating expenditure programs. Examples of such non–network programs include the use of customer standby generation capacity in the North Adelaide area to defer network augmentation, and construction of a small power station at Pinaroo to defer a connection point project.[754]

PB commented that the opex forecast for demand management in ETSA Utilities' proposal is an allowance for the creation of six FTE positions to operate ETSA Utilities' demand management program. PB considers this approach to be prudent and the costs proposed are efficient given the bottom–up nature of ETSA Utilities' forecast. PB therefore recommends the proposed opex allowance for demand management be accepted by the AER.[755]

AER considerations

The NER requires the AER to consider the efficient costs for ETSA Utilities of achieving the opex objectives, one of which is the requirement for ETSA Utilities to meet or manage the expected demand for standard control services.[756] The NER also requires ETSA Utilities to consider non–network alternatives to system augmentation. The AER considers the regulatory framework in general, and the NER in particular, does not absolve ETSA Utilities from having to consider demand management

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[750] Business SA, *Submission to the* AER, August 2009, p. 7.
[751] Business SA, *Submission to the* AER, August 2009, p. 7.
[752] SACOSS, *Submission to the* AER, August 2009, pp. 3–4.
[753] ECCSA, *ETSA Utilities application, a* response, August 2009, p. 38.
[754] PB, *Report – ETSA Utilities*, Sept 2009, p. 156.
[755] PB, *Report – ETSA Utilities*, Sept 2009, p. 156.
[756] NER, clause 6.5.6(a)(1).

solutions to South Australia's electricity demand profile. The regulatory framework requires ETSA Utilities to make provision for efficient demand management solutions. The AER, however, considers that it is not in a position to enforce the uptake of demand management projects by ETSA Utilities. It is the DNSPs responsibility to determine an efficient demand management project while it is the AER's role to assess the prudence and efficiency of the proposed costs. Further details on the regulatory framework for demand management expenditure, and the role and application of the AER's DMIS, are discussed in chapter 14.5.1 of this report.

Under clause 6.5.6(c)(1) of the NER, the AER is required to accept a DNSP' forecast of required operating expenditure of a DNSP that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure reasonably reflects the efficient costs of achieving the operating expenditure objectives. The NER regulatory framework therefore limits the AER's assessment of ETSA Utilities' forecast demand management opex to first, an assessment of whether the expenditure is required to meet or manage the expected demand for standard control services, and second, whether the forecast expenditure amount is prudent and efficient.

The AER considers ETSA Utilities opex proposal for demand management to be a reasonable response to meet or manage expected demand for the next regulatory control period. The AER has reviewed PB's analysis of ETSA Utilities' forecast demand management opex and notes PB's conclusion that ETSA Utilities' approach to be prudent and the proposed costs efficient. The AER also notes that this allowance is in addition to the allowance associated with the DMIS.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is satisfied that ETSA Utilities' forecast demand management opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

8.8.2 AER conclusion on ETSA Utilities controllable opex

The AER has reviewed ETSA Utilities proposed forecast controllable opex allowance and, for the reasons set out in this appendix, is not satisfied that the proposed forecast opex allowance reasonably reflects the opex criteria under clause 6.5.6(c) of the NER. In reaching this conclusion, the AER has had regard to the opex factors set out in clause 6.5.6(e) of the NER. In particular the AER considers the proposed controllable opex:

- does not reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives
- does not reflect the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the opex objectives
- has not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the opex criteria.

As the AER is not satisfied that the opex allowance reasonably reflects the opex criteria, under clause 6.5.6(d) of the NER the AER must not accept the forecast opex proposed by ETSA Utilities. Under clause 6.12.1(3)(ii) of the NER, the AER is therefore required to provide an estimate of the opex for ETSA Utilities over the next regulatory control period which it is satisfied reasonably reflects the opex criteria, taking into account the opex factors. Allowing for the adjustments listed above, the AER's estimate of forecast opex for ETSA Utilities is $997 million (excluding input cost escalation), as set out in table 8.12.

Table 8.12: AER conclusion on ETSA Utilities controllable opex allowance, excluding input cost escalation ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities proposed controllable opex	186.7	197.4	207.7	220.3	229.0	1041.0
Adjustment for network maintenance and repair (capex trade off)	0.0	0.0	0.1	0.1	0.1	0.3
Adjustment for network maintenance (increases in asset ages)	1.6	2.4	3.6	5.0	6.8	19.4
Adjustment to network maintenance (contingency allowance)	1.0	0.9	0.9	1.0	1.0	4.8
Adjustment to network operating costs (network access, monitoring and control growth)	–0.3	0.0	0.0	0.1	0.2	0.0
Adjustment to network growth escalator	0.4	0.8	1.1	1.3	1.4	5.0
Adjustment to network maintenance (economy of scale)	1.0	1.7	2.2	2.8	3.3	10.9
Adjustment for sponsorships and community engagement projects	0.6	0.7	0.7	0.6	0.7	3.3
Total adjustments	4.3	6.5	8.6	10.9	13.5	43.9
AER controllable opex allowance	182.4	190.9	199.1	209.4	215.5	997.3

Note: Totals may not add due to rounding.

8.8.3 Self insurance

ETSA Utilities regulatory proposal

ETSA Utilities commissioned AON Global Risk Consulting (AON Global) to provide actuarial assessments of ETSA Utilities' self insurance costs.[757] Based on AON Global's advice, ETSA Utilities' proposed self insurance allowance for the following risks:[758]

- below deductible property damage
- below deductible liability (including fire liability)
- below deductible motor vehicle
- uninsured poles and wires (resulting from 3rd party damage)
- below deductible and uninsured GSL payments
- uninsured underground and environmental liability
- below deductible worker's compensation.

It is important to note that the data shown in ETSA Utilities' regulatory proposal are not the total self insurance costs proposed. The total self insurance costs are the variation costs shown in ETSA Utilities' regulatory proposal plus the baseline self insurance costs that are included across in other opex categories.[759]

ETSA Utilities' proposed total allowance for self insurance premiums for the next regulatory control period is shown in table 8.13.

[757] AON Global Risk Consulting is a provider of risk management services, insurance and reinsurance brokerage and human capital and management consulting.
[758] AON Global, *Self insurance risk quantification – ETSA Utilities*, May 2009, confidential.
[759] ETSA Utilities, email response, AER.EU.25, 15 September 2009, pp. 1–2.

Table 8.13: ETSA Utilities self insurance costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Baseline costs[a]	3.6	3.6	3.6	3.6	3.6	18.0
Variation[b]	3.4	3.6	3.7	3.9	4.0	18.6
Total self insurance[c]	7.0	7.1	7.3	7.5	7.6	36.5

Source: ETSA Utilities, *Self Insurance Expenditure*, excel spreadsheet, confidential; and ETSA Utilities, email response, issue number AER.EU.25, 15 September 2009, revised schedules I–5 and R–2, confidential.

Note: Totals may not add due to rounding.

(a) Baseline costs are self insurance premiums that were incurred in the 2008–09 base year. These costs are included in other opex categories other than self insurance.

(b) Variation costs represent the difference between the baseline costs in 2008–09 base year and the self insurance premiums recommended by AON Global.

(c) Total self insurance is the summation of the baseline and variation self insurance premiums.

AER considerations

The AER's detailed considerations of ETSA Utilities proposed self insurance allowances are set out in appendix G. In summary, the AER rejects all of ETSA Utilities' proposed self insurance allowances with the exception of the proposed premium for below deductible worker's compensation claims and a small proportion of the proposed public liability premium.

To form a view on the reasonableness of ETSA Utilities' proposed self insurance premiums, the AER considered each proposed premium against five key assessment criteria:

- the attitude of the network service provider to managing risk and its capacity to self insure
- the approaches to funding a future loss when a self insurance event occurs
- the reporting and administration of self insurance.

With respect to the specific self insurance events nominated by ETSA Utilities, the AER considered:

- whether an insurance premium can be determined and whether the self insurance event relates to an incurred cost
- whether the premium estimated is an efficient cost.

The AER considers that these five principles are relevant to the opex objectives and criteria outlined in section 6.5.6 of the NER.

The AER requested ETSA Utilities to remodel its self insurance opex forecast to reflect the AER's adjustments. Based on this modelling, ETSA Utilities provided an updated self insurance premium forecast of $33 million.[760]

AER conclusions

For the reasons discussed, and as a result of the AER's analysis, the AER is not satisfied that ETSA Utilities' proposed self insurance allowance reasonably reflects the opex criteria, including the opex objectives. The AER considers that making an adjustment to ETSA Utilities' forecasts of $33 million results 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 self insurance principles outlined in appendix G and the opex factors.

Table 8.14 summarises ETSA Utilities' proposed self insurance allowance and the AER's draft decision.

Table 8.14: AER conclusion on self insurance allowance for ETSA Utilities, excluding scale escalation ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities proposal	7.0	7.1	7.3	7.5	7.6	36.5
AER adjustments	–6.4	–6.5	–6.7	–6.8	–6.9	–33.2
Total self insurance allowance	0.6	0.6	0.6	0.7	0.7	3.3

Note: Totals may not add due to rounding.

8.8.4 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.[761]

ETSA Utilities regulatory proposal

ETSA Utilities proposed that the cost of raising debt finance be benchmarked as an annual cost per dollar of allowed debt associated with its regulatory asset base (RAB)—that is, the benchmark gearing ratio multiplied by the RAB.

[760] ETSA Utilities, email response to AER modelling request, 13 November 2009.

[761] 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.

ETSA Utilities proposed a total allowance of 23.2 basis points per annum (bppa), comprising:[762]

- 12.0 bppa for direct costs of debt raising
- 11.2 bppa in additional for debt raising costs associated with the 'completion method'.[763]

ETSA Utilities did not propose an allowance for indirect debt raising costs.

ETSA Utilities submitted a report prepared by Competition Economists Group (CEG) on debt raising costs,[764] and a separate confidential appendix dealing with the proposed completion method.[765] ETSA Utilities' proposed benchmark debt raising costs are set out in table 8.15.

Table 8.15: ETSA Utilities forecast benchmark debt raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Debt raising costs	2.1	2.2	2.5	2.7	2.8	12.3
Completion method costs	2.02	2.02	2.02	2.02	2.02	10.2
Total	4.1	4.3	4.5	4.7	4.9	22.5

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 150; and RIN proforma 2.2.2.
Note: Totals may not add due to rounding.

Submissions

The EUAA submitted that the AER should examine ETSA Utilities' claim for debt and equity raising costs in the context of the actual cost of such debt and equity raising considering its ownership structure as a partnership between HEI, CKI and Spark.[766]

ECCSA stated that debt raising costs are already covered in the opex allowance, and that only a new element for additional debt that is required to fund the capex program should be considered.[767] ECCSA stated that debt raising costs did not provide a legitimate reason to increase opex, since they related to future years rather than the understating of a base year. It also noted the ESCOSA opex allowance covered the bulk of debt held by ETSA Utilities, such that the only increase in debt is that needed for new capex.[768]

762 ETSA Utilities, *Regulatory proposal*, July 2009, p. 155.
763 ETSA Utilities, *Regulatory proposal*, July 2009, p. 155.
764 ETSA Utilities, *Regulatory proposal*, July 2009, attachment E.17, CEG, Debt and equity raising costs: A report for ETSA.
765 ETSA Utilities, *Regulatory proposal*, July 2009, confidential appendix F.14.
766 EUAA, *Submission to the AER*, 28 August 2009, p. 11.
767 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 37.
768 EUAA, *Submission to the AER*, August 2009, p. 20.

AER considerations

The AER's detailed analysis and considerations of ETSA Utilities' proposed debt raising costs are set out in appendix I. In summary, the AER considers that:

- 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 its current 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 methodology
- 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 ETSA Utilities is dependent on the number of standard sized debt issues required (based on the debt value of its RAB), and the nominal vanilla weighted average cost of capital (WACC) applying for the final decision (to be incorporated in the amortisation calculation).

Table 8.16 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG methodology and a nominal vanilla WACC of 10.02 per cent.

Table 8.16: Indicative direct debt raising costs with a nominal vanilla WACC of 10.02 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	$1841 million	$4471 million	$4734 million
Gross underwriting fee	Median gross underwriting spread, up front per issue	7.33	7.33	7.33	7.33	7.33
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 (bppa)	10.7	9.5	9.1	8.9	8.9
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.

ETSA Utilities has an opening RAB of $2.77 billion. On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of ETSA Utilities' opening RAB is around $1.66 billion. Based on the ACG methodology, this debt size would require around 7 bond issues. The nominal vanilla WACC for ETSA Utilities is 10.02 per cent. As such, the AER considers that an allowance of 9.1 bppa for debt raising costs is a reasonable benchmark for ETSA Utilities. Using the post–tax revenue model (PTRM), this benchmark is multiplied by the debt component of ETSA Utilities' opening RAB to derive an average debt raising allowance of $1.6 million per annum ($2009–10).

The AER's detailed analysis and considerations of ETSA Utilities' proposed completion method is set out in confidential appendix K. In summary, the AER considers that the costs of the completion method do not represent efficient costs incurred by a benchmark network service provider and no allowance should be provided for this method.

AER conclusion

As a result of its analysis of the information provided by ETSA Utilities, the AER is not satisfied that the proposed benchmark total debt raising costs reasonably reflect the opex criteria, including the opex objectives.

The AER considers that making a $14 million reduction to ETSA Utilities' forecast is likely to result in total forecast debt raising costs that reasonably reflect the opex criteria, including the opex objectives, and is the minimum adjustment 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 8.17 sets out the AER's draft decision on forecast debt raising allowances for ETSA Utilities.

Table 8.17: AER conclusion on debt raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
AER conclusion	1.45	1.6	1.7	1.7	1.8	8.2

8.8.5 Superannuation

ETSA Utilities regulatory proposal

ETSA Utilities submitted that the majority of its employees are members of a multi-employer industry superannuation scheme known as the Electricity Industry Superannuation Scheme (EISS).[769] The EISS is a separate legal entity that is independent of ETSA Utilities. ETSA Utilities stated that the EISS actuary, in conjunction with the EISS Board, independently sets the required employer contributions to ensure that the EISS is appropriately funded. ETSA Utilities' reports that it has received notice from the EISS's actuary of the new contribution rates to apply from 1 January 2009 for employees within each division of the EISS.[770]

ETSA Utilities has advised that a significant proportion of its employees within the EISS have defined retirement benefits which must be fully funded. ETSA Utilities stated that the effects of deteriorating market conditions diminishing the value of investments related to these defined benefit schemes has led to a significant increase in contribution rates above those in 2008–09 in order for the fund to remain fully funded. ETSA Utilities submitted that on the basis of the notice from the EISS actuary, it has been required to increase the total cost of its employer contributions to the EISS for the next regulatory control period.[771]

ETSA Utilities also submitted that its superannuation expense for accounting purposes includes non–cash actuarial adjustments to comply with accounting standards. ETSA Utilities stated that its superannuation expense for regulatory purposes, derived in accordance with the CAM, is based on cash contributions to the EISS. Accordingly, ETSA Utilities submitted that a regulatory adjustment is required to reflect this difference. ETSA Utilities submitted that the difference between this allocation and the accounting allocation results in the calculated adjustment for the 2008–09 base year to be $3.9 million and $6.5 million for prescribed capital and

[769] ETSA Utilities, *Regulatory proposal*, July 2009, p. 161.
[770] EISS, *Report to the Electricity Industry Superannuation Board and ETSA Utilities on the Financial Position as at 30 June 2008 and the Recommended Contribution Level from 2009*, April 2009.
[771] ETSA Utilities, *Regulatory proposal*, July 2009, p. 161.

operating expenditure respectively (in December 2007 dollars). ETSA Utilities included these adjustments to the accounting forecast for the 2008–09 base year in its regulatory proposal for forecast superannuation costs.[772]

ETSA Utilities further submitted that it has allocated these costs between standard control, negotiated and unregulated services in accordance with ETSA Utilities' CAM, with a further split between capex and opex according to the labour components of each category of expenditure.[773] Table 8.18 shows ETSA Utilities' forecast capex and opex superannuation contributions for the next regulatory control period.

Table 8.18: ETSA Utilities' forecast superannuation expenditures ($m, 2009–10)[(a)]

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Capitalised superannuation contributions	8.9	9.2	9.5	9.8	10.2	47.6
Expensed superannuation contributions	10.1	10.5	10.8	11.2	11.6	54.2
Total superannuation contributions	19.0	19.7	20.3	21.0	21.8	101.8

Source: ETSA Utilities, RIN capex proforma 2.2.1 and opex pro forma 2.2.2.
Note: Totals may not add up due to rounding.
(a) On 16 October 2009, ETSA Utilities notified the AER of incorrect inputs into the capital and operating superannuation worksheets leading to an overstatement of its superannuation forecasts in its proposal. The forecast superannuation capex and opex figures in table 8.18 reflect ETSA Utilities' corrected values.

AER considerations

The AER has reviewed the data, calculations and assumptions ETSA Utilities used to estimate its employer contribution to the EISS for the next regulatory control period. The AER notes the actuarial report into ETSA Utilities' obligations to the EISS recommended the following level of employer contributions payable by ETSA Utilities and related companies in respect of each Division of ETSA Utilities' EISS as from 1 January 2009:

- Division 2 members: 28.1 per cent of superannuation salary
- Division 3 members: 61.0 per cent of superannuation salary
- Division 4 members: 52.8 per cent of superannuation salary
- Division 5 members: 10 per cent of superannuation salary or such other amount as agreed with the employer, plus 1.2 per cent to cover administration fees and other subsidies to Division 5 members

[772] ETSA Utilities, *Regulatory proposal*, July 2009, attachment F.7: Derivation of superannuation contribution variation, p. 5.
[773] ETSA Utilities, *Regulatory proposal*, July 2009, p. 161.

- plus for a shortfall on benefit payments: an amount equal to 15 per cent of each benefit payment (excluding Division 5 members and pension benefits) and top up payments for voluntary separation packages and retrenchment benefits for Pension Scheme members.

The AER reviewed the data and methodology ETSA Utilities used to allocate its superannuation contribution requirements between capital and operating expenditure and between standard control, negotiated and unregulated services, based on actual hours worked by ETSA Utilities employees for each category of expenditure. Based on its review, the AER is satisfied that ETSA Utilities has appropriately applied its superannuation liabilities into the forecast superannuation capex and opex categories for the next regulatory control period.

On the basis that the EISS actuary has provided an independent assessment of ETSA Utilities' employee superannuation payment requirements for the next regulatory control period, the AER considers that the level of employer contributions payable for the next regulatory control period submitted by ETSA Utilities is reasonable, given the circumstances prevailing when the forecast was developed.

However, the AER notes that the EISS required contribution rates provided to ETSA Utilities were derived based on an actuarial assessment undertaken in April 2009. The AER also notes the statement by the EISS in its letter to ETSA Utilities, that it will continue to monitor the funding position of the Scheme and that it cannot guarantee that there will not be further adjustments to the contribution levels required to maintain full funding.[774]The AER notes that the economic outlook has changed since April 2009, and this is likely to have had some impact on the outlook for super fund returns and therefore the level of payments required to ensure the scheme remains fully funded.

The AER notes that the level of payments to be made by ETSA Utilities 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, ETSA Utilities' financial obligations in respect of defined benefit superannuation schemes will decline. The AER expects any updated information regarding ETSA Utilities' financial obligations to be reflected in its revised regulatory proposal. The AER also notes that significant revision to such financial obligations may constitute negative pass through events in the next regulatory control period.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is satisfied that ETSA Utilities' forecast superannuation opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

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[774] EISS, *Letter to ETSA Utilities, Electricity industry superannuation Scheme actuarial review*, 28 April 2009.

8.8.6 Feed-in tariffs

ETSA Utilities regulatory proposal

ETSA Utilities stated that as a consequence of the *Electricity (Feed-In Scheme – Solar Systems) Amendment Act 2008*, ETSA Utilities' Distribution Network Operator Licence requires it to allow qualifying generators to feed into the distribution network. These generators are provided a credit against the charges payable by the qualifying customers at a rate of $0.44 per kWh for the electricity they feed into the network.

ETSA Utilities provided forecasts of the payments that it expects to make during the next regulatory control period for feed-in tariffs.[775] Table 8.19 shows ETSA Utilities' forecast of the feed-in tariff payments it expects to make during the next regulatory control period.

Table 8.19: ETSA Utilities' forecast allowances for feed-in tariffs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Feed-in tariffs	5.7	6.9	7.8	8.7	9.7	38.8

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 164.

The forecast allowances for feed-in tariffs shown in table 8.19 are based on ETSA Utilities' assumption that photovoltaic (PV) output will reduce residential energy sales initially by 0.5 per cent, progressively increasing to 0.8 per cent by the final year of the next regulatory control period. ETSA Utilities claimed that the projected uptake of residential PV during the next regulatory control period is lower than that actually experienced in 2008–09 and does not incorporate the recent extension of the Commonwealth government rebate announced in the May 2009 budget. ETSA Utilities considered the projected uptake rate reflects a very conservative estimate. ETSA Utilities also assumed that approximately 55 per cent of the output of solar PV generators is used in-house, directly reducing ETSA Utilities' energy sales to the residential sector.[776]

ETSA Utilities submitted that its forecast allowance for feed-in tariffs for the next regulatory control period should be considered subject to adjustment if a rule change is not successfully concluded.[777] ETSA Utilities also proposed that a pass-through event provide for differences between actual expenditures and its forecast allowances. Should a rule change be successfully concluded prior to the AER's final decision, ETSA Utilities advised that it would no longer seek to include this item of opex in its proposal.[778]

[775] ETSA Utilities, *Regulatory proposal*, July 2009, p. 164.
[776] ETSA Utilities, *Regulatory proposal*, July 2009, p. 85.
[777] ETSA Utilities submitted that it considers that rule reform is appropriate to address the issue of recovering the amounts that DNSPs are obliged to pay under jurisdictional feed-in tariff schemes. To this end, ETSA Utilities proposes to work in appropriate industry forums to address this issue as a rule change to the NER.
[778] ETSA Utilities, *Regulatory proposal*, July 2009, p. 164.

AER considerations

The AER considers that the approach ETSA Utilities used to determine its forecast allowances for feed-in tariffs for the next regulatory control period as reasonable. ETSA Utilities' projected uptake of solar PV generators is consistent with that accepted by the AER in its analysis of demand forecasts in chapter 6 of this draft decision.

The AER has also compared AEMO's forecast of residential PV generated consumption in-house in South Australia for the next regulatory control period.[779] The AER considers that AEMO's forecast residential PV in-house consumption supports ETSA Utilities' forecast allowances for feed-in tariffs for the next regulatory control period.

The AER also considers ETSA Utilities' proposal for a pass through event to provide for differences between actual and its forecast allowances for feed-in tariffs for the next regulatory control period as reasonable and has nominated a feed-in tariff event as a nominated pass through event. Chapter 15 of this draft decision provides details of the AER's assessment of ETSA Utilities' proposal that feed-in tariff events be treated as pass through events.

The AER notes that ETSA Utilities did not include an allowance for feed-in tariffs in its original submission in July 2009 because ETSA Utilities considered that the most appropriate approach to managing its feed-in tariff obligation was through a rule change to the NER. Subsequently, ETSA Utilities has notified the AER that given the limited progress on the NER rule change to date, it is necessary for the AER to incorporate the forecast opex for feed-in tariffs into ETSA Utilities' total opex requirements.[780]

AER conclusion

The AER has reviewed ETSA Utilities' forecast for feed-in tariff expenditure and considers the forecasting approach is appropriate for the purposes of the regulatory proposal, however, the AER acknowledges that developing accurate forecasts of this cost is difficult. The AER has accepted that the difference between the forecast and actual feed-in tariff payments made in any year should be adjusted for through a specific nominated pass through provision.

The AER's considerations of ETSA Utilities' proposed feed-in tariff pass through event are set out at chapter 15 of this draft decision.

8.9 AER conclusion

The AER has considered ETSA Utilities' proposed forecast opex allowance of $1175 million and, for the reasons set out in this chapter, is not satisfied that the forecast reasonably reflects the opex criteria including the opex objectives. In summary, the AER is not satisfied that:

[779] AEMO, *Review of ETSA Utilities sales and demand forecasts*, 1 October, 2009, p. 32.
[780] ETSA Utilities, email response to AER, 23 October 2009.

- the expenditure associated with ETSA Utilities' application of input cost escalators reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives

- the expenditure associated with ETSA Utilities' application of scale escalators reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives

- the expenditure associated with ETSA Utilities' forecast self insurance program is not prudent or efficient

- the expenditure associated with ETSA Utilities' proposed debt and equity raising allowances is not prudent or efficient.

Under clauses 6.5.6(d) and 6.12.1(4) the AER must not accept ETSA Utilities' total proposed forecast opex and set out an estimate which it considers reasonably reflects the opex criteria. To this end, the AER has determined the following specific adjustments to ETSA Utilities' proposed forecast opex:

- $0.3 million reduction to maintenance and repair opex to reflect adjustment to capex/opex trade off

- $5.0 million reduction to reflect revised network growth escalator

- $0.01 million reduction to reflect revised network access, monitoring and control opex to remove the impact of the growth in work volume or network growth.

- $19.5 million reduction to maintenance and repair and emergency response to remove the proposed impact of asset age on forecast maintenance

- $4.8 million reduction to vegetation management to remove proposed 5 per cent contingency allowance

- $10.9 million reduction to emergency response to reflect a change in the economies of scale factor to be applied to the network growth escalator for emergency response

- $3.3 million reduction to sponsorships and community engagement projects

- $1.6 million reduction to reflect adjusted workload escalator[781]

- $38.0 million reduction to reflect revised real input cost escalators

- $33.2 million reduction to the forecast self insurance opex

- $14.3 million reduction to the forecast for debt raising costs.

781 Included in the modelling request advice provided by ETSA Utilities to the AER on 6 November 2009 was a downward adjustment of $1.6 million for proposed opex with the workload escalator recalculated in accordance with adjusted capex and opex.

The AER requested ETSA Utilities remodel its opex forecasts to reflect these conclusions. ETSA Utilities advised that the individual adjustments results in a total reduction to its proposed forecast opex of $131 million ($2009–10) or around 11 per cent. The AER considers that this adjustment results in forecast expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for the total forecast opex to comply with the NER.

After making the adjustments outlined above, the AER considers that a forecast opex allowance that reflects the efficient costs that a prudent operator in the circumstances of ETSA Utilities to achieve the opex objectives is $1044 million. In coming to this view the AER has had regard to the opex factors. The AER's adjustments and total opex allowance are shown in table 8.20.

Table 8.20: AER conclusion on ETSA Utilities' total opex allowance ($m, 2009–10)

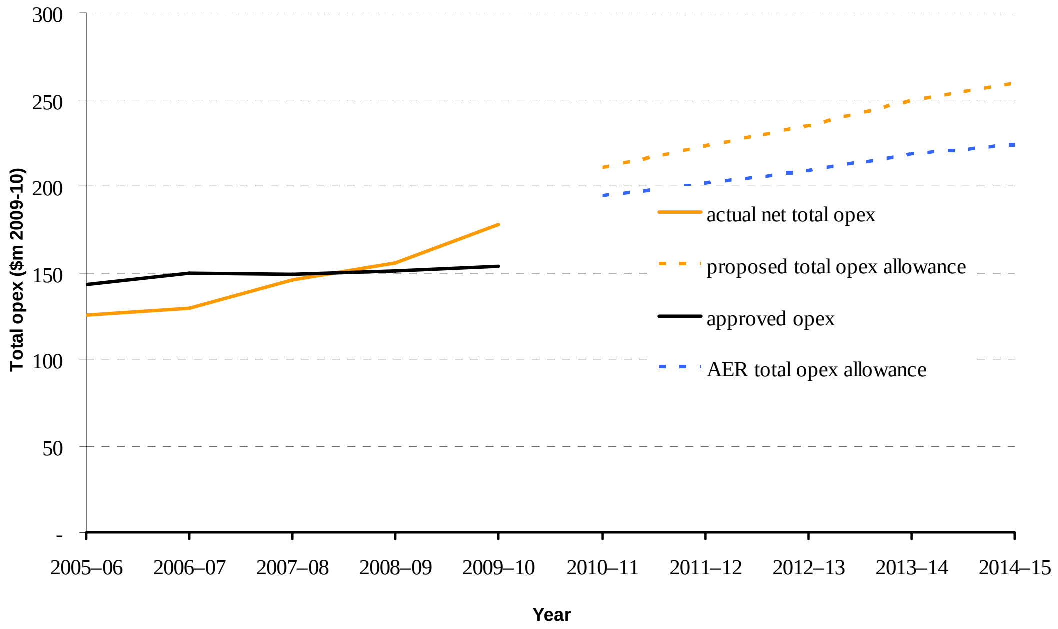
	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities' proposed forecast opex	210.0	222.7	234.5	248.8	259.2	1175.0
Adjustments to controllable opex	–4.3	–6.5	–8.6	–10.9	–13.5	–43.9
Adjustments to self insurance	–6.4	–6.5	–6.7	–6.8	–6.9	–33.2
Adjustment to debt raising costs	–2.7	–2.7	–2.8	–3.0	–3.1	–14.3
Adjustment to input cost escalators	–2.7	–5.5	–8.0	–9.9	–12.0	–38.0
Adjustment for workload escalator recalculated for adjusted capex and opex	–0.2	–0.3	–0.4	–0.3	–0.3	–1.6
Total opex allowance[(a)]	193.7	201.2	208.0	217.9	223.4	1044.0

(a) Includes allowed ETSA Utilities' alternative control metering services costs which are subtracted from the AER approved opex allowance in the PTRM (chapter 16 of this draft decision).

Note: Totals may not add due to rounding.

Figure 8.5 illustrates the AER's draft decision on ETSA Utilities' forecast opex compared to its proposed allowance, and current period opex.

Figure 8.5: ETSA Utilities proposed/actual opex and regulated allowances 2005–2015 ($m, 2009–10)



Source: AER analysis; ETSA Utilities, *Regulatory proposal*, July 2009, RIN Proforma 2.2.2, converted to real terms using ABS data.

8.10 AER draft decision

In accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept ETSA Utilities' proposed forecast opex for the next regulatory control period. The AER is not satisfied that ETSA Utilities' 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 ETSA Utilities' required opex for the next regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out at table 8.20 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 ETSA Utilities during the next regulatory control period. Two key issues discussed in this chapter are the values for the assumed utilisation of imputation credits (gamma) and determination of the tax asset base for ETSA Utilities.

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)[782] that offsets part or all of their personal

[782] In this chapter the terms imputation credit and franking credit are used interchangeably.

income tax liabilities. For eligible shareholders, imputation credits represent a benefit from the investment in addition to any cash dividend or capital gains received.[783]

The generally accepted regulatory approach to date in Australia has been to define the value of imputation credits in accordance with the Monkhouse definition.[784] Under this approach, gamma is defined as a product of the 'imputation credit payout ratio' (F – payout ratio) and the 'utilisation rate' (θ – theta).

Gamma has a range of possible values from zero to one. The AER recently determined a value of 0.65 for gamma in its *Statement of Regulatory Intent* (SORI).[785]

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)[786] of the following matters referred to in clauses 6.5.2 and 6.53 of the NER:[787]

- 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
- the assumed utilisation of imputation credits.

On completion of the WACC review the AER issued the SORI regarding these values, methods and credit rating levels.[788] 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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783 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.

784 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.

785 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009, p. 7.

786 AER, *Final decision, Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, May 2009.

787 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.

788 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 its SORI in relation to gamma are:[789]

- 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 Transition from pre–tax to post–tax regulation

Part C in chapter 6 of the NER requires that DNSPs be regulated using a post–tax revenue model (PTRM). Under clause 6.4.2 of the NER, the PTRM must set out the manner in which the DNSP's annual revenue requirement for each regulatory year of a regulatory control period is to be calculated, and include (but not be limited) to the following requirements:

(1) a method that the AER determines is likely to result in the best estimates of expected inflation; and

(2) the timing assumptions and associated discount rates that are to apply in relation to the calculation of the building blocks referred to in clause 6.4.3; and

(3) the manner in which working capital is to be treated; and

(4) the manner in which the estimated cost of corporate income tax is to be calculated.

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789 NER, clause 6.5.4(e); and NEL, section 7A.

In the current regulatory control period, ETSA Utilities has been regulated using a pre–tax approach. The AER must therefore effect a transition from pre–tax to post–tax regulation as part of this distribution determination for the next regulatory control period.

A jurisdictional derogation requires the distribution determination for ETSA Utilities for the next regulatory control period to incorporate appropriate transitional arrangements to take into account the change from a pre–tax to a post–tax revenue model. These transitional arrangements must be consistent with any agreement between the AER and ETSA Utilities about the arrangements necessary to deal with the transition.[790]

In October 2008, ETSA Utilities provided the AER with a proposed methodology for the transition to a post–tax regime. The AER agreed with ETSA Utilities' proposal with the exception of treatment of assets existing pre July 1992. The AER considers these assets should be excluded from the opening tax asset base in determining the opening tax asset values as at 30 June 2010, unless it could be shown that they are fully depreciated in accordance with applicable taxation rules.

9.2.3 Determining the tax asset base

Under the NER, the AER must estimate the taxable income that would be earned by a benchmark efficient entity as a result of the provision of standard control services, if such an entity operated the business of the DNSP. The estimate is to be calculated using the 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 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.[791]

9.3 ETSA Utilities regulatory proposal

9.3.1 Assumed utilisation of imputation credits (gamma)

ETSA Utilities proposed that gamma should return to the previous regulatory precedent (0.5), and stated it provided persuasive new evidence that the values attributed to gamma are not robust or safe.[792]

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790 NER, clause 9.29.5(b)(1).

791 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.

792 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 245–246.

ETSA Utilities outlined concerns with the SORI, with respect to the AER's:[793]

- assumption of a payout ratio of 100 per cent – its concerns are based on advice from Professor Officer and Mr Feros

- reliance on tax statistics to estimate of the value of imputation credits (theta) – its concerns are based on the Joint Industry Associations' response to the AER's explanatory statement for the weighted average cost of capital

- approach in applying the results from the Beggs and Skeels study[794] – its concerns are based on advice from Associate Professor Christopher Skeels.

9.3.2 Estimated cost of corporate income tax

ETSA Utilities proposed an approach to determining its tax liability based on forecast revenues over the regulatory control period where it applies 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 DNSP.

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.

ETSA Utilities proposed an opening tax asset base derived in a manner consistent with the approach set out in the AER's issues paper on the transition from pre–tax to post–tax and the agreed methodology. ETSA Utilities has established a tax asset base as at 1 July 2010 according to:[795]

- the commencement date of regulation of ETSA Utilities by ESCOSA (11 October 1999) as the starting point to calculate its tax asset base

- straight–line depreciation

- historical acquisitions and disposals prior to 11 October 1999 based on a combination of balance sheet and cash flow movements

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[793] ETSA Utilities, *Regulatory proposal*, 1 July 2009, pp. 243–244; R. R. Officer, *Estimating the distribution rate of imputation tax credits: Questions raised by ETSA's advisers*, Report prepared for ETSA Utilities, 23 June 2009; Gilbert and Tobin, *Review of WACC parameters: Gamma–ETSA price reset*, Peter Feros–Tax Partner, 22 June 2009; C. L. Skeels, *Estimation of γ*, *Report prepared for ETSA Utilities*, 25 June 2009; SFG, *The impact of franking credits on the cost of capital of Australian firms, A report prepared for ENA, APIA and Grid Australia*, 16 September 2008; and NERA, *AER's Proposed WACC Statement–Gamma, A report for the Joint Industry Associations*, 30 January 2009.

[794] D. Beggs and C. L. Skeels, *Market arbitrage of cash dividends and franking credits*, The Economic Record, vol. 82, no. 258, September 2006.

[795] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 257–263.

- historical acquisitions and disposals post 11 October 1999 based on regulatory accounts

- all assets acquired in the period prior to 11 October 1999 attributed to standard control services

- exclusion of shorter life asset acquisitions and disposals from the calculation of the tax asset base prior to 11 October 1999

- work in progress included in the tax asset base as a one off transitional adjustment as at 1 July 2010

- no carried forward tax losses.

Applying this method, ETSA Utilities has proposed a tax asset base as at 1 July 2010 of $1160 million.[796]

To determine the annual tax payable, ETSA Utilities 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 ETSA Utilities is set out in table 9.1.

Table 9.1: ETSA Utilities proposed annual forecast tax liability ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Forecast tax depreciation	73.2	95.8	120.9	146.7	173.6
Tax payable	77.2	81.8	81.3	88.1	91.0
Less value of imputation credits	50.2	53.1	52.9	57.3	59.2
Net tax allowance	27.0	28.6	28.5	30.8	31.9

Source: ETSA Utilities, *Regulatory proposal*, Attachment L.1 PTRM-ETSA Utilities FINAL.xls, July 2009.
Note: Totals may not add due to rounding.

9.4 Submissions

The AER received submissions from ETSA Utilities and the Energy Consumers Coalition of South Australia (ECCSA) on the value of gamma.

Assumed utilisation of imputation credits (gamma)

ECCSA contended, that as the AER has settled on a gamma of 0.65, this value accommodates the points made by Associate Professor Christopher Skeels and Mr Feros by averaging the boundaries identified by the AER in the WACC review.[797]

796 ETSA Utilities, *Regulatory proposal*, July 2009, PTRM.
797 ECCSA, *ETSA Utilities application, a response,* August 2009, p. 54.

ETSA Utilities provided supporting information on theta in the form of further work by Skeels.[798] Skeels addressed a dividend drop-off study prepared by the Strategic Finance Group Consulting (SFG) which was criticised by the AER during the WACC review.[799]

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 ETSA Utilities' proposal and other arguments in terms of:

- estimating the payout ratio (section 9.5.1.1)
- using of tax statistics to infer theta (section 9.5.1.2)
- dividend drop-off studies, including new information from Skeels and SFG (section 9.5.1.3)
- reasonable ranges and estimates of gamma (section 9.5.1.4).

9.5.1.1 Estimating the payout ratio

This section addresses arguments presented by Professor Officer and Mr Feros regarding the AER's assumption of a 100 per cent payout ratio which underlies the SORI.

As noted above, 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 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:

- 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.[800] In effect, this means 71 per cent of all imputation credits, created in a

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798 ETSA Utilities, *Re: Additional material submitted by ETSA Utilities in support of its regulatory proposal for the regulatory control period 1 July 2010 to 30 June 2015, Submission in support*, 28 August 2009, p. 2.

799 C. L. Skeels, *A review of the SFG dividend drop-off study*, *A report prepared for Gilbert and Tobin*, August 2009.

800 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. It is worth

given year, are assumed to be distributed to shareholders in that same year. Once distributed, shareholders are assumed to value these credits at between 0 and 100 per cent of their face value, which reflects the utilisation rate.

However, there was disagreement on the value of retained credits and what happens to the imputation credits that 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:[801]

- there was 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)[802]

- in accordance with the framework proposed by the National Economic Research Associates (NERA), a reasonable estimate of the payout ratio using the analysis suggested by NERA is between 91 and 98 per cent, based on a reasonable set of assumptions, such as:

  - a discount rate somewhere between the risk–free rate and the cost of equity

  - a retention period for imputation credits from one to five years

  - a payout ratio of 71 per cent.

On the basis of these considerations the AER concluded the issue of time value of money loss associated with retained credits was not significant, such that the adoption of an estimate for the payout ratio of 100 per cent was not unreasonable. A payout ratio of 100 per cent was also consistent with the Officer framework and the modelling assumptions in the PTRM which implicitly assume a full distribution of free cash flows.[803]

ETSA Utilities regulatory proposal

ETSA Utilities stated that it has presented new evidence to the AER demonstrating that a payout ratio of 100 per cent is not supportable, namely:[804]

- new material from Professor Officer which expresses significant concerns with the views of Associate Professor Handley and the AER's position in the WACC review

- advice from Mr Feros (a tax partner) of Gilbert and Tobin.

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noting 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).

801 AER, *Final decision, WACC parameters*, May 2009, pp. 419–420.

802 R. R. Officer, *The cost of capital under an imputation tax system*, Accounting and Finance, Vol.34, 1994.

803 AER, *Final decision, WACC parameters*, May 2009, p. 416.

804 ETSA Utilities, *Regulatory proposal*, July 2009, p. 264.

Professor Officer stated:[805]

- Assumptions of a 100 per cent distribution are inconsistent with long-term averages of the economy wide distribution rate of about 70 per cent, with listed companies rarely exceeding this rate. This implies that at least 30 per cent of credits generated have no value.

- If the credits are not redeemed at the time they are created, the 'time value' of the cash redemption they represent is reduced and the Officer framework never addressed this issue, as the paper assumed perpetuities.

- In considering the time value decay of retained credits, these credits are tied to equity cash-flows therefore the appropriate discount rate is the cost of equity.

- The Officer framework did not address the issue of a variable distribution and the paper's conclusions are consistent with an immediate or full pay out of earnings or a delayed payment.

Mr Feros stated:[806]

- The income tax law presents significant impediments to full, effective distribution of franking credits, and that the 'wastage' of credits is an apparent design feature of the imputation system. Furthermore, the Treasury has in the past shown a readiness to not only adopt further specific measures to prevent tax avoidance schemes (such as dividend streaming), but will sometimes do so retrospectively.

- Commercial imperatives mean that companies may not be in a position to fully distribute all of their retained franking credits. A reduction in retained earnings will alter a company's capital structure, and, could have significant implications and influence the ability of a company to raise further capital.

- There a number of provisions in the tax rules which limit the ability of a company to conduct streaming and to distribute imputation credits to certain shareholders (that is, foreign shareholders).

- with respect to investors' incentives and the balance of franked dividends, clients needed to consider the company's owners and their distribution policies, capital requirements, a period of negative profits where it will be unable to distribute dividends and the acquisition of a liquidated business.

Consultant review

The AER engaged Handley to review the recent comments by Professor Officer with respect to the implied assumptions in the Officer framework. Handley advised:[807]

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805 R. R. Officer, *Estimating the distribution rate of imputation tax credits: Questions raised by ETSA's advisers, Report prepared for ETSA Utilities*, 23 June 2009, pp. 1–6.

806 Gilbert and Tobin, *Review of WACC parameters: Gamma–ETSA price reset*, Peter Feros–Tax Partner, 22 June 2009, pp. 2 and 4–8.

- The Officer framework assumes a perpetuity framework (which is clear from the definitions (a) to (g) in Officer's paper). Importantly, this should not be interpreted as a criticism, rather, it should be viewed as a simplification.

- Since all cash flow streams, including associated imputation credits are assumed to be perpetuities then, by definition, a perpetuity means no growth and no growth means full distribution at the end of each period (including imputation credits). In other words, dividends and imputation credits are assumed to be fully paid out at the end of the period (that is, for the purposes of simplicity, it assumed the payout ratio is 100 per cent).

- The Officer framework assumes all free cash flow is fully distributed at the end of each period and so it would be internally inconsistent to assume there is a full distribution of free cash flow but a less than full distribution of the imputation credits associated with that free cash flow.

- An assumption of never paying out retained imputation credits is inconsistent with the general valuation principle of full distribution implicit in the Miller and Modigliani[808], Miles and Ezzell[809], and Officer frameworks. The standard classical tax system valuation frameworks of Miller and Modigliani, and Miles and Ezzell assume there is either a 100 per cent payout of free cash flows each period or, in the event of less than full distribution in one or more periods, there is a settling up at maturity.

- 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.

Handley concluded in his report:[810]

> Valuation is inherently imprecise and accordingly requires the exercise of professional judgement and the making of appropriate assumptions. The current issue of debate centres on the value of a retained imputation credit (relative to the value of a distributed imputation credit). In my opinion, it is totally unreasonable to effectively assume that the current $150 billion in accumulated franking credits has no value. This is extreme.

AER considerations

The AER observes that some of the issues raised by Professor Officer and Mr Feros on behalf of ETSA Utilities were considered by the AER in the WACC review:[811]

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807 J. C. Handley, *RE: Advice on gamma in relation to the 2010–2015 QLD/SA electricity distribution determinations, Memorandum to the AER*, 23 October 2009, pp. 4–10.

808 M. H. Miller and F. Modigliani, *Dividend policy, growth and the valuation of shares*, Journal of business, vol. 34, No. 4, 1961, pp. 411–433.

809 J. A. Miles and J. R. Ezzell, *The weighted average cost of capital, perfect capital markets and project life: A clarification*, Journal of financial and quantitative analysis, vol. 15, No. 3, September 1980, pp. 719–730.

810 J. C. Handley, *RE: Advice on gamma in relation to the 2010–2015 QLD/SA electricity distribution determinations, Memorandum to the AER*, 23 October 2009, p. 28.

- the impacts of distributing imputation credits on the structure of the business. In response to this issue the AER considered:
  - a market-wide estimate rather than industry specific benchmark
  - a dividend reinvestment plan allows for an increase in equity while still releasing dividends
- the discount rate applied to retained imputation credits. In response to this issue, the AER considered:
  - although credits need to be attached to cash flows to be paid out, retained credits need not be attached to cash dividends
  - it could be argued that since retained imputation credits have already been generated from the profits of the firm, the appropriate discount rate is the risk–free rate
- the retention period of between one and five years assumed in the time decay analysis for retained credits. In response to this issue the AER considered:
  - the relevant retention period is that of the average firm in the market
  - it was unaware of any empirical analysis that specifically explores the issue
  - it is reasonable to assume a retention period of one to five years.

Professor Officer and Mr Feros have not provided the AER with new information in these areas and the AER refers interested parties to its final decision on the SORI for detailed responses to these issues.[812] Accordingly, the AER considers that these matters do not constitute a material change in circumstances since the SORI or other relevant factors that, in light of the underlying criteria, would now make that value inappropriate. These matters therefore have not formed part of the AER's considerations in this draft decision.

The AER considers that it has received new information in relation to the following issues:

- reducing the balance of imputation credits
- decay in the value of retained imputation credits
- responses to Associate Professor Handley's and the AER's position on the payout ratio.

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811 AER, *Final decision, WACC parameters*, May 2009, pp. 414 and 416–418; and J. C. Handley, *Further comments on the valuation of imputation credits*, *Report to the AER*, 15 April 2009, pp. 7–8.

812 AER, *Final decision, WACC parameters*, May 2009, pp. 414 and 416–417.

Reducing the balance of imputation credits

The AER notes that ETSA Utilities and its consultant, Mr Feros, discussed a number of limitations to a company's ability to conduct dividend streaming and/or create innovative ways to distribute imputation credits. The AER noted in the WACC review that dividend streaming was one example of how a company might reduce its balance of imputation credits.

Although Mr Feros noted that the Australian Tax Office and the Australian Government can introduce retrospective regulations, it is difficult for the AER to predict:

- what innovative financial activities a company may develop to distribute its imputation credits
- how the Australian Government, the Treasury or the Australian Tax Office may respond to such schemes.

The AER considers that estimating how the Treasury might react to certain schemes and the impact on the payout ratio would be a highly complex process, with any additional benefit unlikely to justify the cost involved.

Further, Mr Feros incorrectly applied the issue of wastage of imputation credits to the estimation of the payout ratio. The AER observes that Mr Feros noted the Explanatory Memorandum to the *New Business Tax System (Imputation) Act 2002*, which states:[813]

> A consequence of generally spreading imputation benefits evenly across members is that members who cannot use, or cannot fully use, imputation benefits will nevertheless receive franked distributions. This results in the 'wastage' of those benefits, which is a design feature of the imputation system.

The AER notes this apparent design feature in the Explanatory Memorandum contemplates wastage through the presence of classes of foreign shareholders who cannot redeem imputation credits rather than preventing their full distribution (affecting the payout ratio). Further, during the WACC review the AER noted another means to distribute retained imputation credits was through the use of a dividend reinvestment plan. The AER has not received any information from interested parties subsequent to the WACC review that demonstrates that a business could not use this as a means to reduce its balance of imputation credits.

Decay in the value of retained imputation credits

ETSA Utilities considered that the advice the AER relied on in the WACC review was based upon flawed assumptions.[814] ETSA Utilities argued that retained imputation credits have zero value.[815] The AER notes the observation made by Handley that there are currently over $150 billion of retained credits according to the

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[813] Gilbert and Tobin, *Review of WACC parameters: Gamma–ETSA price reset*, Peter Feros–Tax Partner, 22 June 2009, p. 3.

[814] ETSA Utilities, *Regulatory proposal*, July 2009, p. 241.

[815] ETSA Utilities, *Regulatory proposal*, July 2009, p. 243.

taxation statistics, and considers that to assume that the entire value of these credits is zero is unrealistic.

The AER also notes that it is not uncommon to use simplifying assumptions with respect to the time value of money. For example the PTRM makes simplifying assumptions about the timing of cash flows. Consistent with its findings in the WACC review, the AER considers that the potential benefits from measuring an estimate of the time value of money in distributed imputation credits is outweighed by the complexity introduced by the extra parameters required to provide this degree of modelling accuracy.

ETSA Utilities has 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 AER's analysis of the value of retained imputation credits inappropriate. The AER considers that there is no persuasive evidence for departing from the AER's position on the payout ratio of 100 per cent reached during the WACC review.

The AER considers that there is not a significant issue of time value loss associated with the value of retained credits, such that the adoption of an estimate for the payout ratio of 100 per cent becomes unreasonable. The adoption of a payout ratio of 100 per cent is also consistent with the Officer framework.

Payout ratio

ETSA Utilities noted that it has new material from Professor Officer which expresses significant concerns with Handley's advice to the AER during the WACC review.[816] Professor Officer disagreed with Handley's advice that the Officer framework had an implicit assumption that imputation credits are fully paid out at the end of the period.[817] Handley disagreed with Professor Officer's view that the Officer framework did not consider the full payout of earnings and that it could be consistent with an immediate or delayed payout of imputation credits. Rather, Handley considered:[818]

- the Officer framework assumes a perpetuity framework (as a simplifying assumption) and therefore assumes no growth and the full distribution of cash flows at the end of each period
- it would be inconsistent to assume there is a full distribution of free cash flow but less than full distribution of the imputation credits associated with that free cash flow
- standard tax valuation classical frameworks assume there is either a 100 per cent payout of free cash flows each period or a settling up at maturity—anything less would be irrational.

816 ETSA Utilities, *Regulatory proposal*, July 2009, p. 243.

817 R. R. Officer, *Estimating the distribution rate of imputation tax credits: Questions raised by ETSA's advisers, Report prepared for ETSA Utilities*, 23 June 2009, pp. 1–6.

818 J. C. Handley, *RE: Advice on gamma in relation to the 2010-2015 QLD/SA electricity distribution determinations, Memorandum to the AER*, 23 October 2009, pp. 4–10.

The AER notes that Handley concluded it is unreasonable to assume that the current $150 billion in accumulated franking credits have no value.[819] The AER agrees with Handley. In particular, the AER considers that the assumption of retaining imputation credits indefinitely is likely to be unrealistic and a theoretical extreme as well as being inconsistent with a perpetuity framework. Further, like Handley, the AER recognises that the assumption of a zero value for retained credits is inconsistent with the Officer framework which is based upon a perpetuity model and has used simplifying assumptions. As Handley noted, this is not a criticism of the Officer framework, rather it is an acknowledgement that in order to analyse highly complex issues simplifying assumptions are used in theoretical models to gain a better understanding of the workings of financial markets.

On the issue of the investor's incentive when a large amount of franking credits build up over time, the AER acknowledges that if a liquidation of a company were to occur that the imputation credits retained might be worthless. That said, the AER also notes that the likelihood of a regulated monopoly, providing essential service infrastructure, becoming insolvent is limited, which is acknowledged by Officer as a 'logical extremity'.[820] The AER also recognises that foreign owners and investors may not value these imputation credits and, as a consequence, any accumulated imputation credits would not affect the likelihood that a business would be acquired due to a large amount of imputation credits being held. However, this issue is only relevant to extent that foreign investors invest in the Australian market, as per the AER's definition of the market benchmark in the WACC review.[821] The AER continues to consider that a large build up of imputation credits would increase the incentives and/or likelihood of domestic investors to acquire such a business, as retained credits have value.

9.5.1.2 Use of tax statistics to infer theta

This section addresses arguments presented by ETSA Utilities regarding the AER's reliance on tax statistics to estimate of the market value of the utilisation rate, in the context of the Joint Industry Associations' submission to the WACC review.

As part of the WACC review, the AER focused on a number of conceptual issues that have been prominent in the previous regulatory debate on the value of imputation credits, including:

- the recognition of foreign investors in the domestic capital market
- the identity of the relevant investor (average / marginal).

Statement of regulatory intent

After considering all of the available information and submissions (including those presented by the Joint Industry Associations), the AER maintained its position with respect to the market definition. Under a domestic capital asset pricing model

[819] J. C. Handley, *RE: Advice on gamma in relation to the 2010-2015 QLD/SA electricity distribution determinations, Memorandum to the AER*, 23 October 2009, p. 28.
[820] R. R. Officer, *Estimating the distribution rate of imputation tax credits: Questions raised by ETSA's advisers, Report prepared for ETSA Utilities*, 23 June 2009, p. 3.
[821] AER, *Final decision, WACC parameters*, May 2009, p. 101.

(CAPM) framework, foreign investors in the Australian market will be recognised in defining the representative investor, but only to the extent they invest in the domestic capital market.[822]

In forming this view, the AER received advice from Handley on nature of the market benchmark for the purposes of estimating the CAPM:[823]

- The question of what impact the introduction of the imputation tax system has had on the cost of equity in Australia can only be answered within a formal equilibrium setting, and ultimately depends on the extent to which the Australian equity market is integrated with global markets.
- The market value of imputation credits should be determined by the value of an investor's actual holdings in the domestic market.
- The AER's conclusion that redemption/utilisation rates sourced from tax statistics are relevant to estimating gamma remains sound.

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.[824] 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 of 0.74.[825]

ETSA Utilities regulatory proposal

ETSA Utilities raised concerns with any method that does not provide a market value of theta. ETSA Utilities argued that tax statistics only measure the usage of imputation credits and not the value attached to imputation credits. ETSA Utilities noted Handley's position that the market value of imputation credits should be determined by the value of an investor's actual holdings in the domestic market. ETSA Utilities argued that the Handley advice did not provide any peer reviewed academic literature to support this position. It also argued that in contrast, NERA has drawn attention to a number of seminal finance papers, such as Brennan in 1970, and Guenther and Sansing in 2007, to demonstrate the tax penalty on dividends will depend on a wealth-weighted average of tax rates across all in investors, not a holdings-weighted average.[826]

ETSA Utilities proposed that no weight should be placed on Handley's theoretical proposition, especially where it is directly contradicted by empirical expert analysis that has been published in peer-reviewed financial (or economic) journals.[827]

ETSA Utilities argued that the papers by Brennan and Guenther and Sansing both demonstrate that the value of imputation credits will be determined by the wealth

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822 AER, *Final decision, WACC parameters*, May 2009, p. 425.
823 AER, *Final decision, WACC parameters*, May 2009, p. 452; and J. C. Handley, *Further comments on the valuation of imputation credits, Report to the AER*, 15 April 2009.
824 AER, *Final decision, WACC parameters*, May 2009, p. 455.
825 AER, *Final decision, WACC parameters*, May 2009, p. 455.
826 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 243–244.
827 ETSA Utilities, *Regulatory proposal*, July 2009, p. 244.

weighted average across all investors. It follows that since Australian residents hold a greater proportion of their wealth in domestic equities, compared with international residents, a holdings based estimate of theta will have an upward bias.[828]

ETSA Utilities considered the use of redemption rate studies to be inappropriate. It argued that the redemption rate of imputation credits (in the tax statistics study) has been shown to lead to an illogical result, on the basis of work conducted by SFG on behalf of the Joint Industry Associations. This would suggest that a policy decision to restrict the investment of foreign investors in Australian capital markets would result in an increase in the market value of distributed imputation credits (and so a reduction in the cost of capital).[829]

AER considerations

With respect to ETSA Utilities criticism that the a theta implied from taxation statistics does not reflect the market value, 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,[830] 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, section 9.5.1.3 of this draft decision discusses some of the weaknesses relating to dividend drop-off studies which estimate a theta using market prices.

The AER has previously considered the arguments presented by ETSA Utilities regarding the imposition of foreign ownership restrictions to support a view that redemption/utilisation rates are not relevant to the estimate of theta in the WACC review. The AER's response to the treatment of foreign investors and wealth holdings is discussed in its summary of its position in the SORI. The AER considers these arguments do not constitute persuasive evidence under clause 6.5.4(g). The AER refers interested parties to the AER's position in the WACC review for responses to these issues, including the advice previously provided by Associate Professor Handley.[831]

9.5.1.3 Dividend drop-off studies

This section considers ETSA Utilities' arguments regarding the AER's approach in applying the results from the Beggs and Skeels dividend drop-off study, including new advice from Skeels and information from SFG.

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.

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828 ETSA Utilities, *Regulatory proposal*, July 2009, p. 244.
829 ETSA Utilities, *Regulatory proposal*, July 2009, p. 244.
830 AER, *Final decision, WACC parameters*, May 2009, p. 120.
831 J. C. Handley, *Further comments on the valuation of imputation credits, Report to the AER*, 15 April 2009, pp. 12–14.

Statement of regulatory intent

The AER considered all of the material before it on the empirical estimates of theta inferred from market prices, and concluded:[832]

- dividend drop-off studies are likely to suffer from multi-collinearity as it is difficult to separate the value investors imply from cash dividends and the imputation credits attached to those cash dividends
- although it was fully considered, the AER did not consider the 2008 SFG dividend drop-off study (2008 SFG study) provided persuasive evidence regarding the value of imputation credits, as it had concerns about:
  - the methodology employed
  - the sampling selection
  - the filtering process undertaken
  - other identified deficiencies
- a reasonable and reliable estimate of theta inferred from market prices is 0.57, taken from the Beggs and Skeels 2006 dividend drop-off study (Beggs and Skeels study).

ETSA Utilities regulatory proposal

ETSA Utilities contended that the Beggs and Skeels study was prepared as a theoretical exercise for academic purposes and it was not prepared with the notion that it would be used to establish prices for infrastructure services.[833]

Submissions

The AER received a submission from ETSA Utilities in support of its regulatory proposal with respect to dividend drop-off studies. ETSA Utilities engaged Skeels to review the 2008 SFG study considered during the WACC review.[834]

ETSA Utilities argued the following conclusions can be drawn from Skeels advice:[835]

- on the face of the 2008 SFG study there were issues that should be interrogated including several of those identified by the AER

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[832] AER, *Final decision, WACC parameters*, May 2009, pp. 441 and 446–447.

[833] ETSA Utilities, *Regulatory proposal*, July 2009, p. 243.

[834] ETSA Utilities, *Re: Additional material submitted by ETSA Utilities in support of its regulatory proposal for the regulatory control period 1 July 2010 to 30 June 2015, Submission in response*, 28 August 2009, p. 2.

[835] ETSA Utilities, *Re: Additional material submitted by ETSA Utilities in support of its regulatory proposal for the regulatory control period 1 July 2010 to 30 June 2015, Submission in response*, 28 August 2009, p. 2.

- upon interrogation a small number of points do warrant correction in the 2008 SFG report but when they are taken into account the effect upon the conclusions is not material

- in the course of interrogating the approach applied by SFG using the Cook's D statistic[836], a new, detailed review of 20 highly influential data points has been undertaken and a detailed interrogation of these has contributed significantly to the accumulated knowledge that had previously been established by SFG, and, Beggs and Skeels

- one of the authors of the Beggs and Skeels study (Associate Professor Skeels), and SFG are now both of the view that the likely value for theta is between 0.23 and 0.57, and is more likely to be at the lower end of that range.

The report prepared by Associate Professor Skeels for Gilbert and Tobin (the Skeels report)[837] is broken up into three distinct parts:

- a comparison of the estimation outputs of the Beggs and Skeels study and the 2008 SFG study

- an examination of the AER's findings about the 2008 SFG study

- a request for further information from SFG about the 2008 SFG study. This part also discussed the resolution of a number of issues, which Skeels considered immaterial, and the updated estimates from SFG that resolve these issues.

Comparison between the Beggs and Skeels study, and the SFG study

Skeels began by comparing the 2008 SFG study to the Beggs and Skeels study and made the following observations:[838]

- the 2008 SFG study uses data from a longer sampling period than Beggs and Skeels (includes data from 10 May 2004 to 30 September 2006). Skeels considers that estimates from a larger sample would be expected to better reflect the true population values

- thetas estimated from the 1 July 2000 to 10 May 2004 sub–sample are very similar (0.57 in Beggs and Skeels compared to 0.52 in the SFG study). Skeels considers that this difference may be due to SFG not accounting for the scaling factor (scaling ex-dividend share prices by one plus the return on the All Ordinaries Index).

- estimates from the 1 July 1999 to 30 June 2000 sample are notably different between the two studies, and this is unlikely to be explained by the scaling factor.

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[836] The Cook's D statistic measures the change in the parameter estimates caused by deleting each observation. The observations which cause the largest changed are then considered to be influential observations.

[837] C. L. Skeels, *A review of the SFG dividend drop-off study*, *A report prepared for Gilbert and Tobin*, August 2009, pp. 8, 10–11 and 13.

[838] C. L. Skeels, *A review of the SFG dividend drop-off study*, *A report prepared for Gilbert and Tobin*, August 2009, pp. 8, 10–11 and 13.

Skeels qualifies this observation by noting the relatively small size of this sub–sample.

- Beggs and Skeels employed filters which excluded observations based on shortcomings in the data or where there were economic grounds to believe observations were unreliable. Skeels cannot definitively state that the larger sample size in the 2008 SFG study is due to the presence of more information or the inclusion of more unreliable observations compared to the Beggs and Skeels study.

- SFG made an erroneous argument that the Beggs and Skeels' results are driven by outliers or influential observations. However, this cannot be known as SFG do not know whether or not the influential observations excluded from the 2008 SFG study were part of the data used in the Beggs and Skeels study.

Examination of the AER's findings

Skeels then examined findings raised by the AER in response to the 2008 SFG study and other studies as part of the WACC review. Skeels:[839]

- agreed with the AER that theta estimates are highly sensitive to the sample selected based upon his own experience in the writing of the Beggs and Skeels study noting:

  - it is important that the stocks in the sample are of high quality (sufficient trades are needed for all the available information to be revealed)

  - the type of data used in the Beggs and Skeels study is difficult to assemble and, in particular, not all of the required data are available in readily accessible sources such as Bloomberg. Skeels contended that an important feature of the SFG study is that considerable attention has been devoted to the development of a 'clean' data set.

- concurred with the AER's finding that SFG did not account for the noise in the data set by adjusting the daily observed ex-dividend share price for the aggregate movement in the market.[840] Skeels argued that it is likely that the impact from not scaling is likely to be immaterial given that the theta estimates in the two studies within the same subsample period are similar.

- concurred that the tax rates applied in the 2008 SFG study did not appear to correspond with the official period over which the various tax rates apply

- considered that multi-collinearity was not a problem in the 2008 SFG study as not all of the coefficients in the regression are statistically insignificant (that is the estimated co-efficient on the cash dividend is statistically different from zero)

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[839] C. L. Skeels, *A review of the SFG dividend drop-off study, A report prepared for Gilbert and Tobin*, August 2009, pp. 15–17, 19 and 22–24.

[840] This is required to separate the movement in the stock price on the ex dividend date from the general movement in the market.

- considered that SFG's larger sample is more likely to reflect the true population than the Beggs and Skeels study and that the differences in filtering and exclusion techniques are likely to be immaterial. Skeels noted if the larger population came with larger standard deviations then so be it

- contended that the filtering and sample selection issues in the 2008 SFG study are potentially important but have not been established by the AER as problems

- considered the differences between the two studies outlined by the AER are largely immaterial and therefore should treat the two studies equally.

Further information from SFG

Skeels concluded by asking questions about the filtering and exclusion techniques SFG used and found:[841]

- by combining economic justifications for the removal of observations based on identifying influential observations with Cook's D statistic, SFG has updated its results. The estimated theta is now significantly different from zero

- the omission of the scaling factor from the 2008 SFG study was a minor issue

- SFG now presents compelling economic justifications for why certain observations should be excluded from the analysis which makes their results more credible

- SFG confirmed that the data filters used by the Beggs and Skeels study were used in the 2008 SFG study and the exclusion of some of the data on the basis of the Cook's D statistic in the 2008 SFG study was an additional level of filtering

- now that the questions involving the filtering of data, exclusion of observations and tax rate assumptions have been resolved there is no reason to consider any of SFG's results other than those provided which exclude the contaminated observations.

AER considerations

Overall the AER considers that the further work by Skeels and SFG does not address all of the concerns raised by the AER during the WACC review about the 2008 SFG study. In particular, the rigour of the data filtering approach applied in the 2008 SFG study remains unresolved. The AER's other concerns are outlined in detail below. Table 9.2 demonstrates that in the same sub–sample period and with a similar number of observations to Beggs and Skeels, the 2008 and 2009 SFG studies appear to have significantly different results. It would be expected that if a similar sub–sample period was used that the coefficients and associated standard errors would be similar to Beggs and Skeels. Instead, the AER observes:

- large standard errors

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[841] C. L. Skeels, *A review of the SFG dividend drop-off study, A report prepared for Gilbert and Tobin*, August 2009, pp. 26–30.

- different coefficients and/or
- economically implausible coefficients.

This calls into question the reliability of the data underlying the 2008 and 2009 SFG studies.

ETSA Utilities argued the Beggs and Skeels dividend drop-off study was prepared as a theoretical exercise for academic purposes and it was not prepared with the notion that it would be used to establish prices for important infrastructure services.[842] It is not clear to the AER why this would detract from its validity or accuracy of the study. The AER considers whether an academic paper was developed for academic purposes rather than a regulatory proceeding is of lesser relevance than whether the academic paper can assist the AER with informing its view on the best estimate of a parameter value. It is also worth noting that published academic papers are typically peer reviewed.

Further, the AER notes that a number of approaches used to estimate parameters in regulatory proposals have been based upon exercises initially written for academic purposes. For example the CAPM defined in the NER has its foundations in the academic literature[843] and it is unlikely at the time that Professor Sharpe contemplated that it would be used by regulators around the world.

Comparison between the Beggs and Skeels study, and the SFG study

Before proceeding to the examination of the AER's criticisms of the 2008 SFG study, the AER makes the following observations on Skeels' report. Skeels compared the estimated thetas from the two studies but did not to highlight the vast differences between the standard errors using the same sampling period. For example, the standard error for the Beggs and Skeels study for the 1 July 200 to 10 May 2004 sub–sample is 0.12 compared to 0.54 in the 2008 SFG study (that is the standard error is approximately 4.5 times larger).[844] This would suggest that the estimates in the 2008 SFG study are less statistically precise than those in the Beggs and Skeels study. Further, Skeels' comparison examined the differences between the Beggs and Skeels study and the unfiltered sample rather than the preferred sample from the 2008 SFG study. In other words, Skeels did not refer to the sample which used the Cook's D statistic which removed 1 per cent of influential observations (theta estimate of 0.19 with an associated standard error of 0.136).

Skeels suggested generally that a study with more data observations is likely to result in estimates which better reflect the true population. However the 2008 SFG study, which uses more observations than the Beggs and Skeels study, did not employ the same filtering techniques or data source as used in the Beggs and Skeels study, making it difficult to assess the reliability of the data used in each of the studies. Accordingly, the only observations the AER can make in comparing the reliability of

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842 ETSA Utilities, *Regulatory proposal*, July 2009, p. 243.

843 See for example W. F. Sharpe, *Capital asset prices: A theory of market equilibrium under conditions of risk*, vol. 19, No. 3, September 1964, pp. 425–442.

844 The standard error of a method of measurement or estimation is the standard deviation of the sampling distribution associated with the estimation method.

the two studies are general views about the estimation results, such as differences between the standard errors.

Addressing the AER's concerns

Skeels recognised the importance of a number of problems previously identified by the AER. However, Skeels argued that the problems identified were not material and the AER had not established their significance. The AER considers these comments are merely speculative (and have not been quantified empirically) and do not constitute persuasive evidence with respect to clause 6.5.4(h) of the NER and the underlying criteria. That said, the AER observes that Skeels attempted to quantify the materiality by requesting further information from SFG.

The AER examined the estimation outputs provided by Skeels which compares theta estimates from Beggs and Skeels, the 2008 SFG study and the 2009 SFG study, as shown in table 9.2.

Table 9.2: Comparison of dividend drop-off subsamples from Skeels' report

Estimation period	Beggs and Skeels (2006)			2008 SFG study			2009 SFG study (Excluding 20 contaminated points)		
	Cash	Franking	N	Cash	Franking	N	Cash	Franking	N
1 Jul 00 – 10 May 04	0.800 (0.052)	0.572 (0.121)	1310	0.895 (0.227)	0.526 (0.541)	1389	1.015 (0.038)	0.129 (0.106)	1386

Source: C. L. Skeels, *A review of the SFG dividend drop-off study, A report prepared for Gilbert and Tobin*, August 2009, pp. 10 and 35.
Note: Brackets denote standard errors of the estimation results.

For the purposes of comparison, the AER selected the same sub–samples examined in the WACC review for both studies, with the estimation results compared by Skeels in the 2008 and 2009 SFG studies. The AER makes the following observations:

- as noted by Skeels, the standard error in the updated results has fallen for the estimated coefficients of both cash and franking from 0.227 and 0.541 to 0.038 and 0.106 respectively
- on the other hand the estimated coefficients have changed substantially:
  - with a dollar of cash dividends being valued at greater than a dollar
  - the value of franking credits has decreased from 0.526 to 0.129, compared to the Beggs and Skeels study being 0.572
- there are 58 more observations in the 2009 SFG study results than that of the Beggs and Skeels study. Although, the number of observations in each subsample are similar (1310 for the Beggs and Skeels study, 1389 for the 2008 SFG study and 1386 for the 2009 SFG study).

The AER notes that both Skeels and SFG have considered results where the coefficient of cash dividends exceeds one dollar as economically implausible and therefore cannot be relied upon.[845] Furthermore, the AER is concerned that a sample size which is similar to that in the Beggs and Skeels study could produce significantly different results (either by having large standard errors or completely different coefficients).

The AER also examined the estimation results that were determined to use the preferred approach at each point in time. The contrasts in the results between each study, as shown in table 9.3, are noticeable.

Table 9.3: Comparison of dividend drop-off subsamples using preferred approaches

Estimation period	**Beggs and Skeels (2006)**			**2008 SFG study (1% influential removed)**			**2009 SFG study (Excl. 20 contaminated points)**		
	Cash	**Franking**	**N**	**Cash**	**Franking**	**N**	**Cash**	**Franking**	**N**
1 July 00 – 10 May 04	0.800 (0.052)	0.572 (0.121)	1310	0.945 (0.059)	0.190 (0.136)	1378	1.015 (0.038)	0.129 (0.106)	1386

Source: C. L. Skeels, *A review of the SFG dividend drop-off study, A report prepared for Gilbert and Tobin*, August 2009, pp. 10 and 35.
Note: Brackets denote standard errors of the estimation results.

The AER observes that the estimation results for the preferred approaches in the SFG studies are similar. This is not completely unsurprising given the two studies use the same data source and the 2009 SFG study includes an additional nine 'influential' observations. The AER also notes that both of the coefficients from SFG's preferred approaches are statistically different to the Beggs and Skeels coefficients. The AER considers it is unusual that three studies which use similar methodologies and are all attempting to estimate theta over the same sampling period would be found to be statistically different.

The AER examined the data and statistical program codes underlying the updated SFG study, and found:

- the updated results were replicable
- the data set used as an input to regression appears not to use historically consistent price and dividend data which may introduce unnecessary noise into the estimation results
- contrary to Skeels' claim, there continues to be an issue with the appropriate use of the corporate tax rates as there remains a three-month lag for the adoption of the 34 and 30 per cent tax rates
- there have been no tests conducted to examine the extent of multi-collinearity, as the AER has previously recognised that dividend drop-off studies are likely to be

845 In other words, one dollar cannot be more valuable than one dollar at the time a cash dividend is valued.

prone to multi-collinearity given the high correlation between cash dividends and the associated franking credits

- although now some economic reasons are included in the Cook's D analysis, the Cook's D analysis may fail to identify observations, which in themselves are not influential, but when combined are jointly influential

- the AER has concerns about the amount of filtering of the data used in the 2008 SFG study.

Given the AER's concerns had regarding the variability in the results and some of the findings in the Skeels report, the AER requested further information from Skeels on two particular areas:

- the differences between the data used in the Beggs and Skeels study, and the 2008 SFG study

- the treatment of influential outliers in the 2009 SFG study.

The AER recognised that, given the commercial-in-confidence nature of the information obtained by Beggs, it may not be able to obtain the data used for this study. Therefore, the AER attempted to ask qualitative questions about the data which it considered would not breach any confidentiality agreements. Skeels' responded:[846]

> The data employed by Beggs and Skeels (2006) were obtained from the CommSec Share Portfolio database for a sample which runs from April 1st 1986 to May 10th 2004. Beggs and Skeels (2006) examined companies and trusts that are reported in the CommSec database as being primarily listed on the ASX. Prior to the estimation of their drop-off regressions, Beggs and Skeels (2006) applied a multi-part filter to the data.
>
> The data employed by Beggs and Skeels (2006) was supplied to David Beggs by CommSec under a strict non-disclosure agreement. Consequently it is not possible for the authors of Beggs and Skeels (2006) to provide the data set and in the absence of the data set I cannot definitively address Questions 1(b) – 1(e).

Skeels' response to the AER's questions about the treatment of influential outliers in the SFG study was:[847]

- SFG focussed on observations that had been determined to be highly influential using Cook's D statistics rather than filtering out observations of dubious economic quality as was done in the Beggs and Skeels study

- SFG's approach had the advantage of being less demanding in terms of time and resources than the approach taken by Beggs and Skeels

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846 C. L. Skeels, *Response to AER questions, Report prepared for ETSA Utilities*, September 2009, p. 4.

847 C. L. Skeels, *Response to AER questions, Report prepared for ETSA Utilities*, September 2009, pp. 6–11.

- in the 2008 SFG study, the exclusion of the top 1 per cent of influential outliers was arbitrary, however, now that economic reasons have been included in the updated study, the approach is no longer arbitrary
- there is no uniquely accepted method to correctly filter a given data set
- the Cook's D statistic may still have some success in detecting a group of observations if it deems one or more of the observations in the group as influential
- the criterion that none of the observations can be influential singly but be jointly influential is a very strong one and quite implausible, a large group of unreliable observations is only likely to occur as a consequence of some event and that such events are likely to be known to market analysts
- one could go through the process of removing those influential observations found to be unreliable and re-estimating the model iteratively, however, this approach is likely to be reduce the advantage of the Cook's D approach being less demanding
- the use of historically consistent price and dividend data makes very little difference to the results.

After examining the information provided by Skeels the AER continues to have a number of concerns which are detailed below. Skeels justified the use of the Cook's D approach over the approach taken in the Beggs and Skeels study due to the Cook's D approach being less demanding. The AER agrees that the Cook's D approach may be an efficient means by which to find unreliable observations but does not accept this is a superior approach in terms of finding unreliable observations to that used by Beggs and Skeels.

It appears to the AER that the approach taken in the Beggs and Skeels study, although it could be more time consuming, is likely to yield a more reliable data set than the estimates in the updated SFG study.

The AER also agrees to some extent with Skeels' characterisation of joint observations and their impacts on the estimation results. The AER agrees that events which would affect a cluster of the results are likely to be known to market practitioners. However, the event need not be as extreme as event such as 'Black Friday'[848], it could be an event that affected only part of the stocks or one stock within the sample. Given that the SFG study has not conducted a rigorous interrogation of the data, there may be jointly influential unreliable observations within the data. This adds to the AER concerns that it is likely that the 2009 SFG study did not remove a number of unreliable observations underlying its estimations, unlike in the Beggs and Skeels study which examined all of the observations.

The AER also continues to have the following concerns:

- the data set used as an input to regression appears not to use historically consistent price and dividend data which may introduce unnecessary noise into the

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848 'Black Friday' refers to the stock market crash on 24 September 1986.

estimation results. SFG adjusted only 9 out of 2175 (or 0.4 per cent of the total sample) observations to test whether this was material rather than consider adjusting all parts of the sample where this might be a factor.

- although SFG has adjusted its tax rates from 36 to 34 per cent, and 34 to 30 per cent, it appears to the AER that there continues to be an issue with the appropriate use of the corporate tax rates as there remains a three-month lag for the adoption of the 34 and 30 per cent tax rates

- the AER is unaware of any tests conducted to examine the extent of multi-collinearity, as dividend drop-off studies are likely to suffer from multi-collinearity as there is a strong relationship between cash dividends and the imputation credits attached to those dividends.

The AER notes that although the results reported by Skeels appear to address a number of the AER's earlier concerns identified in the WACC review, there are still a significant number of issues which demonstrate that estimates provided by SFG are likely to be unreliable. In particular, the AER maintains its concerns regarding the rigour of the filtering technique used by SFG. Further, the variability in the estimation results from the 2008 and 2009 SFG studies may be due to the presence of multi-collinearity, however, this has not been empirically tested. Therefore, the AER cannot confirm whether large variations in estimation results between the SFG studies is due to multi-collinearity or poor filtering techniques.

Hence, although the AER has fully considered the 2008 SFG study and the 2009 SFG study, the AER continues to consider that the estimates from the SFG studies do not constitute persuasive evidence to depart from the value proposed in the SORI. Given that the Beggs and Skeels study has used a more rigorous approach towards filtering outlier observations, the AER still considers the estimated theta from Beggs and Skeels as the most reliable estimate.

The AER considers that ETSA Utilities has not demonstrated that a material change in circumstances since the WACC review or any other relevant factor, in light of the underlying criteria, would now make a gamma of 0.65 set in the SORI inappropriate. The AER considers ETSA Utilities has not presented persuasive evidence justifying a departure from a gamma of 0.65, which is based upon a range of values which is informed by the Beggs and Skeels study, is appropriate.

9.5.1.4 Reasonable ranges and estimates of gamma

This section addresses concerns raised about the AER's approach to selecting an appropriate value for gamma. 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. This generated a reasonable range of gamma estimates for the AER to consider as part of the SORI.

Statement of regulatory intent

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.[849] The AER referred to the point estimate derived from tax statistics as an 'upper bound' of reasonable estimates.[850]

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.[851] The AER referred to this point estimate as a 'lower bound' of reasonable estimates.[852]

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 gamma is 0.65.[853]

Submissions

ECCSA contended as the AER has settled on a value for gamma of 0.65, this value accommodated the points made by Skeels and Feros by averaging the boundaries it identified in the WACC review.[854]

ETSA Utilities regulatory proposal

ETSA Utilities noted Skeels has significant concerns on the use of his original work and more generally with the approach taken by the AER.[855]

ETSA Utilities consultant

Skeels made the following observations about the gamma value determined by the AER and the range of reasonable estimates:[856]

- it is not reasonable to treat the Beggs and Skeels study estimate as a lower bound on gamma
- there is no scientific justification for the AER's proposed gamma of 0.65 obtained by averaging the Beggs and Skeels study and, Handley and Maheswaran 2008 estimates (as the AER ignores the uncertainty inherent in the estimates)
- the AER's proposed estimator of gamma is upwardly biased by construction.

AER considerations

On the treatment of the Beggs and Skeels study as a lower bound, the AER acknowledges the use of terminology of labelling the Beggs and Skeels study's estimate as a lower bound may be inappropriate and was not intended to carry meaning in the statistical sense (that is, confidence intervals).

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849 AER, *Final decision, WACC parameters*, May 2009, p. 455.
850 AER, *Final decision, WACC parameters*, May 2009, p. 467.
851 AER, *Final decision, WACC parameters*, May 2009, pp. 446–447.
852 AER, *Final decision, WACC parameters*, May 2009, p. 467.
853 AER, *Final decision, WACC parameters*, May 2009, p. 455.
854 ECCSA, *ETSA Utilities application, a response,* August 2009, p. 54.
855 ETSA Utilities, *Regulatory proposal*, July 2009, p. 243.
856 C. L. Skeels, *Estimation of γ, Report prepared for ETSA Utilities*, 25 June 2009, p. 2.

In response to the selection of an appropriate range of estimates for gamma, in calculating the upper and lower bounds based upon confidence intervals it was not and continues not to be the focus for determining whether there was or is persuasive evidence to depart from the previously adopted value. The AER considers that the most likely 'true' values of estimated parameters are the point estimates, as the point estimate is the best unbiased estimator. However, the AER adopted a lower value than in Handley and Maheswaran's 2008 study by taking the average of point estimates.

Further, it is unclear to the AER why two estimates derived from different sources, where the inputs and methodologies are considered reliable, cannot be averaged for the purpose of constructing the best point estimate based upon available information. This is in contrast to selecting a lower value in the range based on the 2008 SFG study and Beggs and Skeels, as the AER considers that the inputs in the 2008 SFG study cannot be relied upon.

With respect to Skeels' advice about claims of bias, it is worth noting that Skeels conducted statistical tests on a value (0.74) which was selected as mid–point of estimates from the tax statistics study (0.67 to 0.81).[857] The AER notes Skeels applied standard deviations to calculate the confidence intervals of a sample mean. However, the appropriate measure to determine the goodness of the sample mean is not the standard deviation rather it is the standard error (which is the standard deviation divided by the square root of the sample size). Accordingly, the AER considers that a more correct statistical upper bound would be either to estimate a 95 per cent confidence interval on the estimate of 0.74 used by the AER (noting that it appears that Skeels used utilisation rates of funds rather than the total data set to conduct his analysis). The AER considers the confidence intervals used by Skeels are incorrect and cannot be relied upon to determine whether a value of 0.65, as the upper 95 per cent confidence interval may be lower than what is reported. That said, the AER considers that point estimates or means have the highest probability of representing the true value of a parameter and should be used to inform a range of reasonable estimates.

The AER notes under statistical tests that it cannot be rejected that the point estimate of the Beggs and Skeels study is the same as the previously adopted value (prior to the WACC review) of 0.5 within a 95 per cent level of confidence. In contrast, it can be rejected that the estimates in the Handley and Maheswaran study are different to the previously adopted value. However, as noted above, due to the use of standard deviations rather than standard errors, Skeels' calculations cannot be relied upon. Further, the AER adopted an approach that used several point estimates and recognises limitations of the underlying methodology of each approach. The AER also considers that the point estimates and means from tax statistics and dividend drop-off studies are considered to have the highest probability of reflecting the true population values. The AER has not been persuaded by ETSA Utilities' arguments to depart from the approach of forming a reasonable range of estimates for theta based upon point estimates and selecting a value from this range. On this basis the AER considers that a reasonable estimate of gamma is 0.65.

[857] The AER note that 0.74 can also be considered as a weighted average of observed annual utilisation rates for the period from 1990 to 2004, and that the standard errors need to be calculated based upon the full sample underlying the 0.74 estimate.

9.5.1.5 AER conclusions

The AER considers ETSA Utilities' regulatory proposal and the information provided in support of its regulatory proposal 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 considered it against the underlying criteria. In particular, the AER considers:

- the arguments presented by ETSA Utilities regarding an assumed 100 per cent payout ratio, the recognition of foreign investors and limitations of theta inferred from tax statistics not representing values inferred by the market do not constitute new information
- an assumed 100 per cent payout ratio is consistent with a perpetuity framework implied in the Officer framework and continues to be appropriate given the cost of the complexities in estimating impacts such as time value of decay is likely to outweigh any benefits arising from improvements in accuracy
- the book values obtained from tax statistics are an appropriate proxy for theta estimates
- overall, the further work by Skeels and by SFG does not address a number of the AER's concerns regarding SFG's studies raised during the WACC review, in particular the presence of multi-collinearity and the rigour of the filtering process conducted by SFG
- labelling the Beggs and Skeels study's estimate as a lower bound is inappropriate as it was not intended to carry meaning in the statistical sense
- 0.65 continues to be a reasonable estimate of gamma.

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.

9.5.2 Transition from pre–tax to post–tax regulation

ESCOSA has previously applied a pre–tax WACC in its determinations for ETSA Utilities.[858] Under the pre–tax approach applied by ESCOSA, an allowance for tax was built into the WACC. However, the AER must determine a nominal post–tax WACC pursuant clause 6.5.2(b) of the NER.

Under the post–tax WACC required by the NER, an explicit allowance for tax is made on the basis of cash flow analysis rather than including an implicit allowance for tax within the WACC. To enable the cash flow modelling required to estimate the cost of income tax, the remaining tax value of ETSA Utilities' assets (the tax asset base) is required. This information was not required for the pre-tax approach applied by ESCOSA. Accordingly, the tax asset base must be established to allow transition to the post–tax approach. The AER published an issues paper on this matter in June 2007. The issues paper noted that:[859]

> Setting the tax base at commencement of post–tax regulation is important and will have an impact on the calculation of the tax allowance (tax building block). The AER proposes to establish appropriate values for the tax base in light of the specific circumstances of each business. One of the most notable influences concerns business ownership. The proposed approach involves taking the value of a firm's assets for tax purposes when it first became subject to tax, and rolling these values forward to the date when a post–tax approach is to apply, taking account of relevant tax depreciation rules and actual capex and disposals. In the case of government owned businesses, the proposed approach is similar, but utilises the date and tax base when the business became subject to the NTER [National Tax Equivalence Regime]. A key issue for all businesses will be to distinguish RAB assets from non-RAB assets. However, with inflation and the depreciation of existing assets that comes with passing time, the tax base used in the regulatory accounts will become increasingly reflective of the actual tax base of RAB assets.

The AER requested ETSA Utilities to present its 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 that period (as opposed to a single point in time) was intended to ensure that:

- the proposed tax asset base reflected the underlying regulatory assets and was consistent with regulatory determinations over that period
- 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 ETSA Utilities' proposal with respect to:

858 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination*, *Part A*, April 2005.

859 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, p. 69.

- identifying an appropriate starting point to establish the tax asset base
- reviewing historical depreciation and tax depreciation assumptions
- the treatment of past acquisitions 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.

McGrathNicol found that, based on the information provided, ETSA Utilities' proposed methodology for calculation of its tax asset base appeared reasonable. McGrathNicol also noted that ETSA Utilities' tax asset values were generally verifiable through supporting registers, tax working papers and other documentation.[860]

In summary, McGrathNicol noted that ETSA Utilities:[861]

- established its opening asset base using the commencement date of 11 October 1999
- applied a straight–line method of depreciation to value its tax asset base as at 30 June 2010
- applied the depreciated value of distribution network assets acquired before the date of regulation to be incorporated into the tax asset base as at 1 July 2010
- determined forecast depreciation at an asset category level using straight–line depreciation with all assets within each class assigned weighted average standard and remaining lives
- did not include shorter life asset acquisitions and disposals in the calculation of its tax asset base prior to 1998
- relied on historical balance sheet movements to determine asset acquisitions and disposals between 1 February 1992 and 28 January 2000
- included capital contributions for the purposes of the tax asset base, allocated them to a single asset category and depreciated them based on the weighted average life of the assets for which the contributions were received

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[860] McGrathNicol, *Assessment of E*TSA*'s proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 2 October 2009, p. 13.

[861] McGrathNicol, *Assessment of E*TSA*'s proposed methodology and calculation of its tax asset base*, 2 October 2009, pp. 4–13.

- included work in progress in the tax asset base as a one-off transitional measure
- applied an appropriate method to separate RAB and non–RAB components.

AER considerations

Under clause 6.5.3(2) of the NER, ETSA Utilities' 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
- 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 ETSA Utilities' tax proposals, the AER considers that these proposals demonstrate that:

- the values of ETSA Utilities' proposed tax asset bases reflect tax values associated with their RAB assets
- the proposed tax remaining lives and tax standard lives reflect the tax lives of its RAB assets.

9.5.3 Removal of metering assets

As discussed in chapter 5 of this draft decision, metering assets used for alternative control services need to be removed from the standard control services RAB. This adjustment extends also to the asset base for tax purposes. The AER has therefore removed these metering assets from the tax asset base for standard control services. The size of this adjustment ($60.8 million) was based on advice received from ETSA Utilities.[862]

9.5.4 Gifted assets

ETSA Utilities informed the AER that it had made an error in the calculation of its tax allowance.[863] ETSA Utilities stated it had not included forecasts of assets gifted to it by customers in its calculation of the tax allowance for its regulatory proposal. Because gifted assets are treated as income for tax purposes, this omission means that ETSA Utilities' proposed tax allowance was too low (other things being equal) in its regulatory proposal. ETSA Utilities provided forecasts of gifted assets to the AER and requested the AER to use these forecasts in its calculation of the tax allowance.[864]

The AER has included the gifted asset forecasts proposed by ETSA Utilities in the calculation of the tax allowance for this draft decision. However, given the short notice given by ETSA Utilities regarding this error, the AER may review this matter (including ETSA Utilities' forecasts of gifted assets) in its final decision.

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[862] ETSA Utilities, email to the AER, issue no: AER.EU.42, 13 November 2009.
[863] ETSA Utilities, email to the AER, Gifted assets, 30 October 2009.
[864] ETSA Utilities, email to the AER, AER modelling request, 12 November 2009.

9.6 AER conclusion

The AER considers that there is no persuasive evidence for departing from the gamma of 0.65 per cent set in the SORI. ETSA Utilities has 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. 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 ETSA Utilities' PTRM and roll forward model are consistent with the tax provisions of the NER. The AER has included in its tax calculations adjustments for the removal of metering assets used for alternative control services and the inclusion of gifted assets that were omitted by ETSA Utilities. The latter adjustment explains why ETSA Utilities' tax allowance is higher than proposed by ETSA Utilities.

The allowance for corporate income tax determined by the AER is shown in table 9.4.

Table 9.4: AER conclusion on ETSA Utilities corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	31.9	33.0	32.4	34.0	35.2	166.6

9.7 AER draft decision

In accordance with clause 6.12.1(7) of the NER the estimated cost of corporate tax to ETSA Utilities for each regulatory year of the next regulatory control period is as specified in table 9.4 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 ETSA Utilities' proposed asset lives used to calculate its 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 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 ETSA Utilities' 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 ETSA Utilities regulatory proposal

ETSA Utilities proposed a straight–line approach to calculating depreciation in the post–tax revenue model (PTRM). The regulatory depreciation allowances it proposed for the next regulatory control period are set out in table 10.1.[865]

Table 10.1: ETSA Utilities' proposed regulatory depreciation ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Regulatory depreciation	100.5	115.4	130.4	147.7	165.2	659.1

Source: ETSA Utilities, PTRM.

10.4 Submissions

No submissions were received regarding ETSA Utilities' calculation 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 to calculate an allowance for regulatory depreciation include:[866]

- 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.[867]

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 ETSA Utilities and used in its roll forward model (RFM) are consistent with those lives used by ESCOSA 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

865 ETSA Utilities incorrectly labelled the figures in table 14.3 (p. 252) of its regulatory proposal as 'regulatory depreciation', even though these figures do not include the required adjustment for inflation of the RAB (that is, negative depreciation).

866 Forecast inflation is also a relevant input and is discussed in chapter 11.

867 The RAB and forecast capex are discussed in chapter 5 and 7 of this draft decision respectively.

clause 6.5.5(b)(1) of the NER. In most cases, the AER would expect the standard 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.

10.5.1 Remaining asset lives and standard asset lives

Regulatory depreciation has been calculated by the PTRM on the basis of ETSA Utilities' proposed remaining and standard asset life inputs, the opening RAB and the forecast capex values.

ETSA Utilities regulatory proposal

To calculate the regulatory depreciation allowances for its existing assets (by asset classes) ETSA Utilities applied the remaining asset lives rolled forward from the start of the current regulatory control period.

In calculating the regulatory depreciation allowances for its forecast capex, ETSA Utilities largely maintained the approach applied during the current regulatory control period. As such, forecast capex values were allocated into most of the same asset classes and standard asset lives as approved by ESCOSA.[868] However, ETSA Utilities did propose three new asset classes and the consolidation of two existing asset classes into a single class.

Vehicles

During the current regulatory control period, vehicles were included in one asset class, with a standard life of 10 years. However, ETSA Utilities considers that this standard life is not consistent with the significant proportion of ETSA Utilities' vehicle expenditure which relates to light vehicles, which ETSA Utilities notes are generally replaced around every 3 to 4 years.

ETSA Utilities proposed a new asset class named 'Vehicles— light fleet' with a standard life of 5 years, so as to more accurately reflect the planned replacement cycle of light vehicles. It also proposed that the existing vehicles asset class be renamed 'Vehicles—heavy fleet' to reflect the nature of additional heavy vehicles acquired from 1 July 2010. Heavy vehicles were expected by ETSA Utilities to have an economic life of around 20 years.

ETSA Utilities proposed that the regulatory written down value of all vehicles as at 1 July 2010 be left in the vehicles - heavy fleet asset class to avoid the need for assumptions in relation to the historical mix of assets.

Low voltage supply and metering

During the current regulatory control period, capital expenditure on low voltage supply and on metering was included in one asset class, with a standard life of 30 years. ETSA Utilities noted that changes to its financial systems now allow it to separately identified the capital cost of metering and low voltage supply, and therefore it proposed that these assets be treated as separate asset classes for the next regulatory control period.

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[868] ETSA Utilities, *Regulatory proposal*, July 2009, p. 250.

ETSA Utilities proposed a standard life of 55 years for low voltage supply, as it considered the characteristics of these assets to be similar to those of lines and cables. It also proposed a standard life of 15 years for meters based on an assessment of the functional and technological life of the meters, together with associated communications and software.

Land

ETSA Utilities noted that in accordance with the AER's regulatory information notice, the existing single asset category for land will be segregated into two categories, system and non–system land, from the start of the next regulatory control period. As land is not depreciated, this change does not affect the forecast depreciation allowance for the next regulatory control period.

Office equipment

ETSA Utilities argued that the expected balance of the office equipment asset category at 30 June 2010 is negligible and proposed that this balance be consolidated within the information systems asset category.

AER considerations

Remaining lives

The AER reviewed the remaining lives as at 1 July 2005 and 1 July 2010 proposed by ETSA Utilities and included in its RFM. The AER considers that these remaining lives have been calculated in accordance with clause 6.5.5(b) of the NER. The remaining lives (as at 1 July 2005) used by ETSA Utilities in its RFM were consistent with the remaining lives used in the models used by ESCOSA in its 2005 determination, while the remaining lives (as at 1 July 2010) used in the PTRM were rolled forward from the start of the current regulatory control period.

Standard lives

The AER has reviewed the standard lives used by ETSA Utilities in its RFM. With one exception, the standard lines used by ETSA Utilities were consistent with the standard lives used by ESCOSA during the current regulatory control period and are therefore consistent with clause 6.5.5(b)(3) of the NER. However, the AER noted the standard life for office equipment of 10 years in the RFM is not consistent with the standard life of 5 years used by ESCOSA. ETSA Utilities has agreed to revise this standard life.

For the next regulatory control period, ETSA Utilities has largely proposed to retain the same standard lives as for the current regulatory control period. Where ETSA Utilities has retained consistency in the standard lives of the assets, the AER accepts that these standard lives are still a reasonable reflection of the expected economic life of these assets, consistent with clause 6.5.5(b)(1) of the NER.

As noted above, however, there were a number of asset categories for which ETSA Utilities proposed different standard lives. The AER reviewed the proposed changes to the standard lives of heavy vehicles, light vehicles, low voltage supply and metering[869] and accepts that these revised standard lives reflect the economic life of these assets, consistent with clause 6.5.5(b)(1) of the NER. The AER also accepts the balance of the office equipment asset category being included in the information systems asset category as these assets are related and have the same standard lives (5 years) as determined by ESCOSA.

Summary

The remaining and standard asset lives approved by the AER for ETSA Utilities as at 1 July 2010 are set out in table 10.2.

Table 10.2: ETSA Utilities approved remaining and standard asset lives (years)

Asset class	Standard life	Remaining life
System assets		
Sub-transmission lines and cables	55	49.7
Distribution lines and cables	55	20.8
Distribution transformers	45	19.1
Substations	45	17.2
Low voltage supply	55	14.9
Communication	15	8.2
Land[b]	na	na
Easements[b]	na	na
Net customer contributions	40.2	35.1
Non–system assets		
Information systems	5	4.9
Plant and tools/furniture and fittings	10	6.8
Vehicles - heavy fleet	20	7.1
Vehicles - light fleet	5	na[a]
Buildings	40	25.1
Land[b]	na	na

(a) Asset category for new additions from 1 July 2010, no opening asset value transferred from other categories.
(b) These assets are not depreciated and therefore do not have asset lives.

[869] As discussed in chapter 2, metering assets are to be treated as alternative control services in the next regulatory control period.

10.6 AER conclusion

The AER has assessed the remaining lives and standard lives used by ETSA Utilities as inputs to its PTRM, and the resulting regulatory depreciation allowance, in accordance with clause 6.5.5 of the NER.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined ETSA Utilities 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 10.3.

Table 10.3: AER conclusion on ETSA Utilities' regulatory depreciation ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Regulatory depreciation	100.3	113.1	126.6	142.4	157.9	640.4

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 ETSA Utilities. The AER has determined the depreciation allowances for ETSA Utilities set out in table 10.3 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 ETSA Utilities 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),[870] 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:

[870] 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).[871] 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:[872]

- 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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[871] AER, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, May 2009..

[872] 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 the SORI regarding these values, methods and credit rating levels.[873] 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[874]); 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.

[873] AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009.

[874] The term 'underlying criteria' is italicised in the NER, however, it is not defined in the NEL or NER.

The national electricity objective (NEO) is defined in the NEL as:[875]

> 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:[876]

> … 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.

Table 11.1: WACC parameters in the SORI

Parameter	**Value**
Gearing level (Debt/Equity)	0.60
Nominal risk–free rate	10 year CGS
Market risk premium	6.5%
Equity beta	0.80
Credit rating level	BBB+

Source: AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009.

The AER determined in the SORI that the nominal risk–free rate is to be calculated:

- on a moving average basis of the annualised yield on Commonwealth government securities (CGS)

[875] NEL, Part 1, section 7.

[876] AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009.

- using a maturity of 10 years
- 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 ETSA Utilities regulatory proposal

ETSA Utilities proposed a rate of return on capital of approximately 9.36 per cent.[877]

The parameters proposed by ETSA Utilities are shown in table 11.2. The methods, values, parameters and credit rating proposed are consistent with the SORI with the exception of the market risk premium (MRP).

Table 11.2: ETSA Utilities proposed WACC parameters

Parameter	ETSA Utilities	SORI
Gearing level (Debt/Equity)	0.60	0.60
Nominal risk–free rate[a]	4.22%	4.22%
Market risk premium	8.00%	6.50%
Equity beta	0.80	0.80
Credit rating level	BBB+	BBB+
Debt risk premium[a]	4.57%	N/A
Expected inflation rate[a]	2.47%	N/A
Nominal vanilla WACC[a]	9.52%	N/A

Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.
(a) Indicative only, to be updated.

ETSA Utilities' proposed parameters are detailed in turn below.

11.3.1 Gearing

ETSA Utilities proposed to use the parameter value specified in the SORI for the proportion of debt funding (gearing).[878]

11.3.2 Nominal risk–free rate

ETSA Utilities proposed to use the method specified in the SORI for the nominal risk–free rate.[879]

[877] ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.
[878] ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.
[879] ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.

11.3.3 Market risk premium

ETSA Utilities considered that a MRP of 6.5 per cent, as determined in the SORI, is inappropriate and proposed a MRP of 8 per cent. It argued regulatory stability and certainty are desirable but are not an end in themselves, and what is primarily required is for the AER to have regard to the evidence presented.[880]

In support of its proposal, ETSA Utilities commissioned reports from the Competition Economists Group (CEG) and from Professor Robert Officer and Doctor Steven Bishop (Officer and Bishop).[881]

11.3.4 Equity beta

ETSA Utilities adopted the parameter values specified in the SORI for the equity beta.[882]

11.3.5 Debt risk premium

ETSA Utilities proposed an indicative debt risk premium (DRP) of 4.57 per cent, noting that this figure will be updated for the final determination based on the agreed averaging period. ETSA Utilities accepts 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.[883] In support of its proposal, ETSA Utilities submitted reports from the CEG and the Victorian electricity DNSPs (Victorian DNSPs).

CEG examined the relative merits of using data from Bloomberg and CBASpectrum in measuring the debt risk premium. Overall, CEG concluded that it would not be reasonable to place sole reliance on the Bloomberg fair value estimates for estimating the benchmark DRP.

The Victorian DNSPs' report was submitted to the AER in June 2009 as part of consultation on the Advanced Metering Infrastructure (AMI) roll out in Victoria. This report criticised the AER's approach to measuring the DRP in previous regulatory determinations, which relied on data from Bloomberg.

11.3.6 Expected inflation

ETSA Utilities adopted the approach used by the AER in the NSW electricity distribution determination and the PTRM final decision for determining the forecast inflation rate.[884]

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880 ETSA Utilities, *Regulatory proposal*, July 2009, p. 240.

881 CEG, *The market risk premium and risk–free rate proxy under the NER and in a period of financial crisis, A report for ETSA*, 26 June 2009; and R. R. Officer and S. Bishop, *Market risk premium—An estimate for 2010 to 2015, Report prepared for ETSA*, 26 June 2009.

882 ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.

883 ETSA Utilities, *Regulatory proposal*, July 2009, p. 245.

884 ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.

11.4 Submissions

The AER received submissions from ETSA Utilities, the Council on the Ageing Seniors Voice (COTA), the South Australian Council of Social Service (SACOSS) and the Energy Consumers Coalition of South Australia (ECCSA).

The COTA, the SACOSS and the ECCSA commented on:

- the proposed increase in the overall cost of capital from the parameters specified in the SORI[885]
- the need for a holistic rather than mechanistic approach to adopting values, methods, parameters and the credit rating level for the WACC.[886]

The COTA and the SACOSS also noted that ETSA Utilities' proposed changes to the WACC of 0.5 per cent result in an increase in revenue from $15 to $20 million dollars per annum.[887]

The ECCSA noted that:[888]

- during the time of the WACC review and SORI the global financial crisis (GFC) placed downward pressure on the nominal risk–free rate (noting the CEG report commissioned by ETSA Utilities) and the high commodity prices pushed market returns upwards. The ECCSA contended that this resulted in the MRP being unsustainably high at the time of the WACC review
- prima facie there does not appear sufficient new evidence to support ETSA Utilities' position that the MRP should be raised at all, let alone to 8 per cent
- the AER considered the need for regulatory certainty as important feature in meeting the NEO. In the event that the AER agrees with ETSA Utilities that a MRP of 8 per cent is appropriate, then it must no longer think the need for regulatory certainty is important and should therefore re-examine its position on the nominal risk–free rate (adjusting for any expectations that may bias the risk–free rate upwards–for example, government spending) and the equity beta (using an equity beta based upon empirical estimates from the WACC review)
- the setting of the WACC parameters cannot be done in isolation or done on a mechanistic basis. To isolate one or two elements and accept others overlooks the inter-dependence of the elements. Accordingly, if the AER considers there is persuasive evidence to depart from any one value, method or credit rating level determined in the SORI, it should re-open all other values, methods and the credit rating level.

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[885] SACOSS, *Submission to the AER*, August 2009, p. 3; and COTA, *ETSA distribution price review*, 27 August 2009, p. 5.

[886] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 56.

[887] SACOSS, *Submission to the AER*, 28 August 2009, p. 3; and COTA, *ETSA distribution price review*, 27 August 2009, p. 5.

[888] ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 51–56.

ETSA Utilities submitted supporting information on its proposed DRP in the form of updated analysis from CEG.[889]

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 a gearing ratio of 0.60.[890]

Regulatory requirements

The underlying criteria used by the AER in its SORI in relation to gearing are: [891]

- 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.

ETSA Utilities regulatory proposal

ETSA Utilities has proposed to adopt the parameter values specified in the SORI for the proportion of debt funding.

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[889] ETSA Utilities, *Re: Additional material submitted by ETSA Utilities in support of its regulatory proposal for the regulatory control period 1 July 2010 to 30 June 2015*, 28 August 2009, pp. 2–3.

[890] AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009.

[891] NER, clause 6.5.4(e); and NEL, Part 1, section 7A.

Issues and AER considerations

The gearing ratio of 60 per cent proposed by ETSA Utilities 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
- generates a forward-looking rate of return that is commensurate with prevailing conditions in the market for funds
- together with values, methods and a credit rating for the other parameters, provides a service provider with a reasonable opportunity to recover at least the efficient costs and provides a service provider with effective incentives for efficient investment
- is appropriate having regard to the economic costs and risks of the potential framework in under and over investment.

On this basis, the AER considers that its proposed value achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[892]

AER conclusion

The gearing ratio of 60 per cent proposed by ETSA Utilities 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 capital asset pricing model (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 volatility on a day to day basis. For this reason, an averaging method is used to minimise volatility in observed bond yields.

Regulatory requirements

The SORI stated 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.

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[892] NER, clause 6.5.4(e).

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.[893]

The underlying criteria used by the AER in the WACC review relating to the nominal risk–free rate are: [894]

- 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.

ETSA Utilities regulatory proposal

Method and averaging period

ETSA Utilities has proposed to adopt the method specified in the SORI for the nominal risk–free rate.[895]

Convenience yield

CEG recommended either the use of a convenience yield of 79 basis points or a MRP of 8 per cent. ETSA Utilities does not propose that a 'convenience yield' of 79 basis points be applied to the risk–free rate as it proposes a MRP of 8 per cent (consistent with CEG's advice).

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[893] NER, clauses 6.5.2(b) and 6.5.2(e).

[894] NER, clause 6.5.4(e); and NEL, Part 1, section 7A.

[895] ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.

Issues and AER considerations

Method and averaging period

The method used to estimate the nominal risk–free rate in ETSA Utilities' regulatory proposal (which includes the proposed averaging period) is as specified in the SORI and is accordingly accepted by the AER.

The AER has accepted the averaging periods nominated by ETSA Utilities as it considers the period and proposed dates are in accordance with 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 period will remain confidential but only until the averaging period has expired.

Convenience yield

The AER observes ETSA Utilities' regulatory proposal does not propose that a 'convenience yield' of 79 basis points be applied to the method used to estimate the nominal risk–free rate as it proposes a MRP of 8 per cent (consistent with CEG's advice). Therefore, the AER has not examined the merits of the use of a convenience yield in this decision. That said, the AER notes Energex and Ergon Energy have both proposed the 79 basis point adjustment to the nominal risk–free rate and a MRP of 6.5 per cent in their regulatory proposals.[896] The AER has examined CEG's report in the context of the Queensland draft distribution determination and concludes that the use of a 'convenience yield' adjustment is inappropriate.[897]

AER conclusion

The method used to estimate the nominal risk–free rate in ETSA Utilities' regulatory proposal is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

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 5.37 per cent (effective annual compounding rate). The AER will update the risk–free rate, based on ETSA Utilities' specified averaging period, at the time of its final decision.

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 (that is, 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

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896 Energex, *Regulatory proposal for the period July 2010 – June 2015*, July 2009 p. 240; and Ergon Energy, *Regulatory proposal to the Australian Energy Regulator – 1 July 2010 to 30 June 2015*, 1 July 2009p. 387.

897 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 241.

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.[898]

The AER considers the underlying criteria relating to the NER requirements that are of particular relevance to determine the MRP are:[899]

- 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 AER considers the revenue and pricing principles that are of particular relevance to the method used to estimate the MRP are:[900]

- 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.

ETSA Utilities regulatory proposal

ETSA Utilities considered that a MRP of 6.5 per cent is inappropriate and has proposed a MRP of 8 per cent.[901] This is based on advice from CEG and Officer and Bishop.[902] This advice implies that the AER has not taken adequate account of the impact of the GFC for ETSA Utilities' next regulatory control period.

CEG concluded that the prevailing long-run average MRP measured relative to the yield on nominal CGS is above 8.3 per cent, and the risk–free rate in the NER should be set at least 79 basis points above the yield on nominal CGS (if the 79 basis point adjustment is adopted, the MRP should be reduced by 79 basis points).[903]

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898 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009, p. 7.
899 NER, clause 6.5.4(e).
900 NEL, Part 1, section 7A.
901 ETSA Utilities, *Regulatory proposal*, July 2009, p. 240.
902 ETSA Utilities, *Regulatory proposal*, July 2009, p. 240.
903 CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, p. 49.

Officer and Bishop examined the underlying basis and reasoning that the AER applied to support its determination of a MRP of 6.5 per cent and also reviewed CEG's analysis.[904] Officer and Bishop:[905]

- noted that they have been asked to recommend a MRP that is expected to prevail over the period 2010 to 2015
- advocated under 'normal' circumstances the use of a long-term historical average of excess returns,[906] however, the MRP expected to prevail in the period which the MRP will apply is well above 6.5 per cent (based upon a five–year rather than ten–year term)
- concluded there is evidence to support a MRP in the range of 7 to 12 per cent over the horizon from July 2010 to June 2015, with 8 per cent being a conservative estimate at the lower end of this range
- noted the AER acknowledged in the WACC review that the current MRP is above the long-term average, and this informed Officer and Bishop's view that the prevailing MRP for the next regulatory control period is a conservative 8 per cent.

CEG and Officer and Bishop also raised issues in relation to a convenience yield on the risk–free rate, use of long term historical data, accounting for the value of imputation credits and the GFC.

Examination of long term historical averages of excess returns

Officer and Bishop advocated the use of a longer time series to calculate the long-term historical average of excess returns, as it will not only improve statistical accuracy but also weight events according to the likelihood of occurrence.[907] Officer and Bishop argued that is in contrast to the approach taken in the WACC review which considered multiple periods. However, they noted the recent and sharp decline in the annual long-term historical average of excess returns (of –46 per cent in 2008) can be argued to be a result of lower expected cash flows from businesses, higher risk (therefore a higher rate of return) or some combination (with the higher rate of return being the substantive cause).[908]

During the WACC review the AER criticised using an adjustment which places less weight on 2008 than other years in the long-term historical average of excess returns. In response, Officer and Bishop outlined the importance of having a long data series rather than engaging in a discussion over the appropriateness of using adjustments. They argued the use of a shorter period for a long-term historical average can lead to an over or under estimate of the long-term average if large infrequent positive or negative events occur in the estimation period, such as the 2008 crash.[909]

904 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 2.
905 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, pp. 3 and 19.
906 The AER notes Officer and Bishop refer to this as the long-term historical MRP.
907 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 4.
908 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 8.
909 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 16.

Accounting for imputation credits

Officer and Bishop addressed comments made in the WACC review regarding earlier reports relating to the ACCC and the Victorian Office of the Regulator General's (ORG) views on MRP.[910] Contrary to the AER's statements, they pointed out that their previous report did not argue whether the ORG's decision to use 6 per cent took imputation credits into account. Rather, they argued that the long-term historical average of excess returns at the time did not adjust for imputation credits.[911] Further, the AER was incorrect in its assertion that the long-term historical average had been adjusted for imputation credits in Professor Davis' work for the ACCC.[912]

Impact of the global financial crisis

CEG argued the GFC has affected markets since August 2007. This has subsequently resulted in an increase in risk aversion, and therefore the MRP, due to:[913]

- investor wealth being substantially reduced
- losses in the market tending to be associated with higher than average returns after those losses
- expected equity market volatility increasing
- DRPs being at historically high levels
- a substantial premium placed on liquidity in financial markets.

CEG quoted the Reserve Bank of Australia's (RBA) statement on monetary policy from November 2008:[914]

> World financial markets have come under severe stress in the period since the last Statement. Strains in credit markets escalated in early September, and the period since then has been marked by further large declines in equity prices and exceptional volatility across a range of markets…
>
> …The renewed turmoil was sparked by the failure or near-failure of a number of financial institutions in the United States and Europe…
>
> …These events saw an intensification of the credit tightening that was already beginning to take hold in a number of countries. While this had previously

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910 Officer and Bishop refer to the Essential Services Commission of Victoria (ESC) which was known as the Office of the Regulator General (ORG) at the time of the decision of a MRP of 6 per cent. See 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.

911 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 17.

912 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 17.

913 CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, pp. 3–13.

914 RBA, *Statement on monetary policy*, Statement, 10 November 2008, p. 1.

been mainly apparent in increased funding costs, which were typically passed on to borrowers in the form of higher lending rates, the renewed turmoil saw this develop into a serious tightening in credit availability. As confidence in the financial sector deteriorated, banks became more uncertain about their ability to sustain their funding, and this in turn made it more difficult for them to lend to sound borrowers in the non-financial sector.

CEG used this quote to demonstrate that current financial conditions are uncertain, therefore a departure from an MRP 6.5 per cent in the SORI is warranted.

Officer and Bishop examined other indicators that may demonstrate the current MRP prevailing over 2010 to 2015 is higher than the MRP adopted in the SORI. They examined the DRP from the viewpoint of the CAPM[915] and considered it is not clear whether the debt beta, the MRP or both have changed to explain the increase in the DRP (from 120 to 319 basis points). However, they did not expect the debt beta to have more than doubled, so an increase in the MRP is more than likely to be expected.[916]

Dividend growth model and implied volatility estimates

CEG and Officer and Bishop examined forward-looking estimates of the MRP derived from dividend growth models (DGM) and implied volatilities from the ASX200 Index.

The DGM has been used by interested parties and some regulators to estimate the implied return on equity based upon current share prices. In this model it is assumed that current share prices represent the present value of the future stream of dividends from the shares being examined. The most commonly used form of the DGM used is defined with two stages of forecasts as:

$$p_0 = \sum_{t-1}^{n} \frac{D_t}{(1+k_e)^t} + \frac{D_{n+1}}{(k_e - g)(1+k_e)^n}$$

where:

p_0 is the share price

n is the number of periods in the second stage

t is the number of periods in the first stage

D_t is the dividends expected in the first stage

D_{n+1} is the dividends expected in the second stage

k_e is the return on equity

g is the expected growth rate of dividends over the second stage.

Dividends for the first stage are generally derived from market forecasts and then are expected to grow at a constant rate over time in the second stage of the DGM. It is also generally assumed that the second stage continues into perpetuity. In order to

915 The CAPM can be used not only to predict the return on an equity portfolio but also the return on a debt portfolio.

916 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 14.

obtain a forward-looking estimate of the return on equity it values are assumed/ obtained for all the variables except for the return on equity and the formula is then solved for the remaining unknown variable (the return on equity). Once the estimated return on equity is obtained, an estimate of the nominal risk–free rate is subtracted from the return on equity to provide a forward-looking estimate of the MRP.

CEG argued DGM analysis provides the most appropriate basis for estimating the forward-looking MRP as it relies upon contemporaneous data and forecasts.[917] CEG found:[918]

- the DGM analysis implies a MRP of 8.3 to 16.7 per cent using:
- data from ASX200 Index businesses
- assumptions about dividend growth reverting to historical measures of long-run growth (either real Gross Domestic Product (GDP) or index-linked CGS) or the MRP (6 per cent)
- an assumption about dividends accumulating over 125 years
- dividend per share forecasts
- the best estimate of the prevailing forward-looking MRP is in the vicinity of 8.9 per cent.

To support its conclusion of its DGM analysis, CEG contended:[919]

- the assumption that risk premiums will 'settle down' in the future is neither a reason for or against setting a high risk premium now
- it appears that in the WACC review the AER based its conclusion on the MRP primarily on the results of DGM analysis, therefore, if the AER continues to place primary weight on DGM estimates it should adopt its recommendation of a MRP of 8 per cent based upon its most recent analysis
- the new evidence provided since the AER's WACC review (which also includes a company by company build up for the DGM, observations about implied volatilities and considers the context of the AER's WACC decision) suggests that the MRP should be increased to account for the higher volatility occurring in this five-year period.

Officer and Bishop also analysed estimates of the MRP from DGM analysis.[920] They noted that the average derived from CEG's DGM approach is slightly higher (14.6 per cent) than the 14.2 per cent reported[921]. They also presented DGM analysis from

917 CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, pp. 14–15.
918 CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, pp. 16–20.
919 CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, pp. 24–29.
920 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 5.
921 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 13. CEG models what the MRP will be at the beginning of the period, and the average over the regulatory

Bloomberg which provides a long-term forecast of the MRP (as at 18 June 2009) of 4.6 per cent.[922] However, they discounted the forecast provided by Bloomberg as it:[923]

- has not been adjusted for the value of imputation credits
- is likely to be anomalous due to recent market conditions
- is based upon a (long-term) perpetuity view of cash flow forecasts compared to the other forward-looking methods which use shorter term views, which are more relevant for determining a MRP for 2010 to 2015.

Officer and Bishop also considered that MRP estimates derived from the implied volatilities of options on a stock market index is a better predictor than using a historical average in current conditions.[924] The implied volatilities method relies upon obtaining an estimate of two variables. First, the implied volatilities of stock options is obtained using the Black-Scholes option pricing model. Second, an estimate of the unit price of risk implicit in empirical estimates of CAPM parameters is obtained in order to convert the implied volatilities into an estimate of the MRP.

The Black-Scholes option pricing model for call options is defined as follows:

$$C(S,T) = SN(d_1) - Ke^{-r_f(T-t)}N(d_2)$$

where:

$N(\ )$ is the standard normal cumulative distribution function

$T-t$ is the time to maturity

S is the spot price of the underlying asset

K is the strike price of the underlying asset

r_f is the risk-free rate (effective annualised rate)

$$d_1 = \frac{\ln\left(\frac{S}{K}\right) + \left(r_f + \frac{\sigma^2}{2}\right)(T-t)}{\sigma\sqrt{T-t}}$$

$$d_2 = d_1 - \sigma\sqrt{T-t}$$

σ is the implied volatility (volatility in the log-returns of the underlying asset)

d_1 is used to estimate the expected benefit of acquiring a stock outright

d_2 is used to estimate the net present value of paying the excercise price on the expiration day.

Similar to the DGM approach, to obtain the implied volatilities all variables in the Black-Scholes model, except for the implied volatilities, must be known in order to obtain an estimate of the implied volatilities. The implied volatilities only provide an

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period (14. 6 per cent), if it is assumed the MRP will fall from its current level to 6 per cent by the end of ETSA Utilities' regulatory period. See CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, p. 20.

922 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 13.

923 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 13.

924 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 3.

indication of the level of volatility of the underlying asset (which is the stock market in Officer and Bishop as they examine call options for the ASX200 Index).

Once an estimate of the implied volatilities is provided, Officer and Bishop estimated the required return per unit of implied volatilities based upon a method developed by JF Capital Partners.[925] They note an estimate of the unit price of risk implicit in empirical estimates of CAPM parameters is about 50 basis points per unit (for example a 7 per cent MRP implies a volatility of 14 per cent).[926]

Using this methodology (based upon implied volatilities of ASX200 Index 12-month call options), Officer and Bishop found:[927]

- the implied MRP from the implied volatility of the longest call option (12 months) is 30.5 per cent, implying the 12-month MRP is 15 per cent which is then faded to the ‘equilibrium MRP’ (long-term historical average) over three years (or up to five years)
- a forward MRP derived from current volatility is 13 to 15 per cent
- assuming a standard deviation of 14 per cent, a mean MRP of 6.5 per cent and an implied volatility of 30.5 per cent provides for a current one-year MRP of 14 per cent
- using different reversion horizons over a five-year window suggest a range of 6.5 to 11.8 per cent
- based upon its analysis of different holding strategies and views held by Oxera it considers that the most appropriate period of mean reversion for the MRP (to 6.5 per cent) is over three years
- using its preferred mean reversion path provides for a geometric average MRP of 8 per cent for 2010 to 2015.

Issues and AER considerations

This section analyses ETSA Utilities’ proposal in accordance with the requirements of 6.5.4(g) of the NER, namely, whether there is persuasive evidence to justify a departure from the MRP of 6.5 per cent set in the SORI. This analysis examines whether there has been a material change in circumstances since the SORI with respect to each of the underlying criteria used by the AER, or whether any other relevant factor currently before the AER means that the value of 6.5 per cent is no longer appropriate. Specifically, this section examines ETSA Utilities’ proposal and supporting consultant reports as they have addressed:

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925 The AER notes that at least until February 2009, Officer held the position of Chairman at JF Capital Partners Funds Manager. Refer to JIA, *Submission to the AER’s review of the weighted average cost of capital parameters—Appendix AA*, Submission in response to AER explanatory statement, February 2009, p. 3.

926 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 8.

927 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, pp. 9–11.

- the impact of imputation credits on historical estimates of the MRP
- the use of long-run historical averages of excess returns
- term of the MRP and prevailing conditions
- DGMs and implied volatilities analysis.

Accounting for the value of imputation credits

Officer and Bishop addressed comments made by the AER in relation to a previous Officer and Bishop report considered during the WACC review, in relation to whether and where imputation credits were taken into account by the ACCC/ORG. Officer and Bishop invited the AER to provide evidence that the long-term historical average of excess returns in Professor Davis' advice to the ACCC/ORG had been adjusted for imputation credits.[928]

The AER notes it has received submissions in the past from interested parties making representations that the MRP of 6 per cent did not consider the value of distributed imputation credits and therefore understated the value of the MRP. The AER notes it has responded to this issue previously but there appears to be some confusion over the AER's position. The AER considers it important to clarify its position and so will re-iterate its response to the submissions received during the WACC review on this issue.

The AER did not state in the WACC review that the long–term historical average of excess returns was adjusted for imputation credits. Rather the AER stated:[929]

> In the explanatory statement, the AER included extracts from both Davis' report and the ACCC's decision. These extracts demonstrated that:
>
> - Davis had regard to the value of imputation credits in interpreting historical estimates of the MRP—which suggested '…an estimate of 6–7 per cent might not be unreasonable'*
>
> - Davis explicitly 'grossed-up' dividend growth model estimates of the MRP for a gamma of 0.5 (which was consistent with Davis' recommended gamma and consequently that adopted by the ACCC and ORG)—which suggested '…an ex ante market risk premium of between 4.5 and 7 per cent with figures at the lower end of that range probably more applicable'
>
> *** These historical estimates were not explicitly 'grossed-up' to reflect the value of imputation credits, as such 'gross-ups' would have been erroneous. This is because the historical estimates considered were based on historical excess returns under a classical tax system.** (emphasis added)

Rather than commenting on the adjustment of long–term historical averages of excess returns, the AER made a factual observation that the MRP of 6 per cent had been set by the ACCC having regard to value of imputation credits (gamma) being set at 0.5

[928] R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 17.
[929] AER, *Final decision, WACC parameters*, May 2009, p. 183.

(based upon advice from Professor Davis). The AER then examined studies which did examine the impact of gamma on long-term historical averages of excess returns and noted caution should be taken with any such approach.[930]

The AER notes that Officer and Bishop's views in its 2008 report are as follows:

- the best estimate of the MRP is a long-term historical average of excess returns and should be given primary weight
- the long–term historical average of excess returns used by the ACCC did not explicitly include the impact of imputation credits
- when gamma is 0.5, the long–term historical average of excess returns is 7 per cent
- given that weight should be given to the long term historical average of excess returns, the MRP should be 7 per cent.

This lead Officer and Bishop to make the following conclusions:[931]

> The market risk premium of 6% was originally based on evidence that excluded any explicit consideration of a component to reflect any value of imputation tax benefits in the historical MRPs. **Consequently the 6% can be viewed as an estimate of the MRP when this value is zero**…
>
> …An overlay of the need for regulatory certainty encourages us to recommend that there be no change in the widely used 6% under a view that imputation tax benefits have no value **but it this is not enough to prevent our recommendation of 7% when imputation benefits are included**. (emphasis added)

Given this advice, the Joint Industry Associations made the following statement:[932]

> However**, a 6 per cent MRP is predicated on imputation credits having no value to investors**. If imputation credits have a value of 0.5 at the time of creation (consistent with past regulatory practice) there is convincing and persuasive evidence that a 6 per cent MRP is not appropriate. (emphasis added)

It appears Officer and Bishop's advice to the Joint Industry Associations did not disclose that the original basis for the MRP of 6 per cent (the ACCC's decision) not only relied upon long-term historical averages of excess returns, but also the impact of imputation credits on the estimated MRP using DGM analysis. It is correct to state the long-term historical averages of excess returns used in forming the ACCC's view on the MRP did not adjust for imputation credits. However, it is incorrect to state that the MRP set by the ACCC did not consider the impact of imputation credits, as it was discussed in Davis's advice. Omitting this information resulted in the Joint Industry

930 AER, *Final decision, WACC parameters*, May 2009, pp. 207–208.

931 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 39.

932 JIA, *Network industry submission – AER Issues Paper – Review of the Weighted Average Cost of Capital (WACC) parameters for electricity transmission and distribution*, Submission in response to AER issues paper, September 2008, p. 79.

Associations' assertion that the MRP in regulatory decisions is predicated on imputation credits having no value. The AER demonstrated that this assertion was incorrect in the WACC review, as the ACCC did explicitly consider imputation credits. Further, the AER notes Officer and Bishop have acknowledged that Davis, in his advice to the ACCC, considered the effect of imputation credits in the DGM analysis.[933]

In the context of the treatment of imputation credits, and the above analysis, the AER considers that ETSA Utilities, through the report by Officer and Bishop, has not demonstrated a material change in circumstances since the WACC review, or presented any other relevant factor that, in light of the underlying criteria, would now make a MRP of 6.5 per cent set in the SORI inappropriate.

Examination of long-term historical averages of excess returns

Officer and Bishop, in their advice to ETSA Utilities, advocated the use of pre-1958 data to estimate long-term historical averages of excess returns. This is consistent with their advice to the Joint Industry Associations which was considered by the AER in the WACC review. The AER raised concerns relating to the use of pre-1958 data, noting the views of Associate Professor Handley about the adjustments made to the data to account for dividends by Lamberton. The AER noted:[934]

> …the dividend yield in the pre-1958 data series constructed by Lamberton is based on an equal weighted rather than value weighted dividend yield. The AER noted the finding of Brailsford et al that this would therefore be expected to be biased towards high dividend paying small stocks. That is, an equally weighted yield (which is the one being used) would be expected to be greater than a value weighted yield (which is the one desired)…
>
> …The second bias relates to how dividend yields were incorporated into stock return series constructed by Lamberton. The dividend yield series effectively assumes that non-dividend paying businesses had the same dividend yield as the average of dividend paying businesses.
>
> Handley clarifies that the adjustment made to the historical data for the two biases identified above were made by the Sydney Stock Exchange (SSE), and not by Brailsford, Handley and Maheswaran. Specifically, the SSE applied an adjustment factor of 0.75. However, Officer's 1989 study was not based on the adjusted SSE data series.
>
> Handley confirms his view that an adjustment is required to correct for the biases, for the reasons outlined in the Brailsford, Handley and Maheswaran paper. Brailsford et al considered a range for the adjustment of 0.65 to 0.75 was defensible, and accordingly there was no strong evidence to suggest a different adjustment factor should be applied.

The AER has not received any further information relating to this issue and therefore considers it is unclear whether the benefits outlined by Officer and Bishop (reducing the impact of 'one in 125 year' events distorting estimates) are outweighed by the concerns raised by Handley and the AER about the noise and accuracy in the data. Therefore, the AER continues to consider that although weight should be given to pre-1958 data, it should be considered in conjunction with other periods which exclude

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933 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 17.

934 AER, *Final decision, WACC parameters*, May 2009, p. 195.

pre-1958 data. In the WACC review, the AER considered numerous estimation periods (1883–2008, 1937–2008 and 1958–2008).[935]

In the context of the examination of long-term historical averages of excess returns, and the above analysis, the AER considers that ETSA Utilities, through the report by Officer and Bishop, has not demonstrated a material change in circumstances since the WACC review, or presented any other relevant factor that, in light of the underlying criteria, would now make a MRP of 6.5 per cent set in the SORI inappropriate.

Term of the MRP and prevailing conditions

The AER recognised in the WACC review that, rather than being competing considerations, there are considerations which interact with each other when providing guidance about the best estimate of the MRP. First, there is a need for the MRP to be a forward-looking estimate, which provides a best estimate of the MRP over the term over which the market portfolio is assumed to be held (5, 6, 7 years, etc.). Currently, under the SORI the term is ten years, which is consistent with the term on the nominal risk–free rate. In other words, while the MRP in the SORI is informed by long-term historical data (that is over 100 years in some cases), the excess returns from this approach are based upon a return above the 10-year risk–free rate, which is consistent with the nominal risk–free rate defined in the SORI. Second, the estimate needs to account for prevailing conditions at the time of decision. When taken together these two considerations require the MRP to reflect the prevailing expectations for the relevant investment term, formed as at the relevant point in time, with that point in time being at the time of the determination. For example, if a short-term estimate of the MRP is adopted, say three years, then the impact of prevailing conditions are likely to have a greater influence on the estimate of a forward-looking three-year MRP. However, for longer-term estimates of the MRP, prevailing conditions are likely to have a smaller impact under normal market conditions, as it is expected that market conditions will return to some form of equilibrium in the medium to long term.

ETSA Utilities, CEG and Officer and Bishop noted the MRP prevailing over the 2010 to 2015 period is likely to be higher than the MRP proposed in the SORI due to the GFC. CEG and Officer and Bishop highlighted a number of different measures, such as forward-looking MRPs, impacts on the equity markets and debt market measurements to illustrate this point. They also noted that the AER in the WACC review recognised the impact of the GFC in determining a MRP of 6.5 per cent. Further, CEG outlined the views of a number of different parties during 2008 discussing the impacts of the GFC to support its position. The AER agrees generally that estimates of the short-term MRP are likely to be above the long-run equilibrium MRP, however, it disagrees with the view that the MRP should be estimated over a five-year term (from 2010 to 2015).

As discussed in the WACC review, the AER considers the term for which the MRP is measured must be consistent with the term of the nominal risk–free rate for internal

[935] AER, *Final decision, WACC parameters*, May 2009, pp. 204 and 237–238.

consistency with the CAPM.[936] The AER notes that the return on equity is defined in clause 6.5.2(b) of the NER:

> $k_e = r_f + \beta_e \times MRP$
>
> 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

The SORI defined the method used to estimate the nominal risk–free rate having a term of 10 years. The AER considers using a MRP that is measured for a five-year period and a nominal risk–free rate based upon a ten-year period (as ETSA Utilities proposed) would result in a return on equity which is inconsistent with the both the return required over regulatory control period and the term of the nominal risk–free rate. The AER notes that this is to be distinguished from the AER's views about the weight given to using long-run historical averages or measures based upon forecasts (for example dividend growth models). For example, if a long-run average of excess returns were to be measured, the AER considers that for the purposes of consistency, that excess returns need to be calculated against the 10-year risk–free rate and not the 5-year risk–free rate.

The need for consistency between the term of the risk–free rate and MRP has been recently argued by Value Adviser Associates (VAA)[937] in support of Australia Post's draft price notification to the ACCC:[938]

> The appropriate term of the risk–free rate used in the CAPM and for estimating the cost of debt which we argue should be 10 years… (p. 3)
>
> and
>
> It is desirable that the risk–free rate be the same in all 'appearances' in equation (3) i.e. it has the same maturity or at least it is essential that it is used consistently when estimating a spread and when applying that spread to a risk–free rate.

CEG and Officer and Bishop did not address this issue as they were instructed to estimate the MRP over the term of ETSA Utilities' regulatory control period. That said, the AER considers that due to refinancing risk and the NER requirement that the same nominal risk–free rate term be used in the cost of debt, a forward looking estimate based upon a 10-year term may be more appropriate. Further, a departure from a 10-year term for the nominal risk–free rate may be harmful to regulatory stability, by changing positions within such a short timeframe from the WACC review, and result in outcomes that would not achieve efficient investment. The AER

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936 AER, *Final decision, WACC parameters*, May 2009, p. 187.

937 The AER notes that Bishop is a founder and director of Value Adviser Associates. VAA, *Team,* Dr Steven Bishop, <http://www.vaassociates.com.au/team/dr-steven-bishop.html>, Accessed on: 16 October 2009.

938 VAA, *Regulatory WACC for Australia Post– Commentary, Draft*, June 2009, pp. 3 and 5.

also notes that ETSA Utilities has not proposed to depart from a 10-year term defined in the SORI.

Based upon a 10-year nominal risk–free rate and the need for consistency in the CAPM, the AER considers the appropriate period to measure the MRP using a approaches which attempt to average out forecast MRPs on an annual basis (for example dividend growth models) for ETSA Utilities is 2010 to 2020. That said, the AER considers the approaches presented by ETSA Utilities' consultants cannot be relied upon due to the concerns identified in this decision.

With regard to prevailing conditions, the AER observes that CEG quoted the RBA statement on monetary policy from November 2008:[939]

> World financial markets have come under severe stress in the period since the last Statement. Strains in credit markets escalated in early September, and the period since then has been marked by further large declines in equity prices and exceptional volatility across a range of markets…
>
> …The renewed turmoil was sparked by the failure or near-failure of a number of financial institutions in the United States and Europe…
>
> …These events saw an intensification of the credit tightening that was already beginning to take hold in a number of countries. While this had previously been mainly apparent in increased funding costs, which were typically passed on to borrowers in the form of higher lending rates, the renewed turmoil saw this develop into a serious tightening in credit availability. As confidence in the financial sector deteriorated, banks became more uncertain about their ability to sustain their funding, and this in turn made it more difficult for them to lend to sound borrowers in the non-financial sector.

While these and other statements were relevant and considered at the time of the WACC review, there have been no indications that financial conditions have worsened compared to those prevailing at the time of the WACC review (May 2009). Rather, there are now signs that markets are beginning to recover from the effects of the GFC, as summarised in the following publications:

- the Organisation for Economic Co-operation and Development's (OECD) June 2009 world economic outlook:[940]

> 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's recent statement on monetary policy:[941]

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939 RBA, *Statement on monetary policy*, Statement, 10 November 2008, p. 1.
940 OECD, *Economic outlook no. 85*, Report, 17 June 2009, pp. 25 and 29.

> 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…
>
> …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.

During the WACC review, the AER considered that prevailing conditions, dominated by the GFC, justified an increase in the MRP to 6.5 per cent, noting that this was either the result of the medium-term MRP being above its long-term value, or that there had been a structural break.[942] The AER now considers that market volatility appears to be reverting to pre-GFC levels, implying that the MRP may also be returning to the AER's best estimate of the long-term equilibrium MRP of 6 per cent. The AER observes there a number of indicators that suggest that this is occurring, such as implied volatilities and stock prices (see section on MRP estimates).

Another indicator of improving financial conditions is increases in CGS yields. The AER observes that one of CEG's previous arguments in the WACC review discussed the inverse relationship between the return on equity (or the MRP) and the nominal risk–free rate appears to be absent from its most recent report. Previously, CEG argued:[943]

> The reduction in the regulatory ROE illustrated … is largely due to the fall in CGS yields in the latter half of 2008 – a fall in yields that is demonstrably coincident with a rise in the actual cost of equity observed in the market. This inverse relationship between government bond yields and the return on equity is not surprising and is well documented in the finance literature.

The AER notes that although CEG referred to the return on equity in its report, the finance literature it references examines the inverse relationship between yields and the MRP. In response to this issue, the AER considered in the WACC review that the MRP is likely to move in the opposite direction to the yield on CGS.[944] The AER also observes that CGS yields are currently increasing which would suggest the observed MRP is likely to be falling.

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941 RBA, *Statement on monetary policy*, Statement, 7 August 2009, pp. 1 and 3.
942 AER, *Final decision, WACC parameters*, May 2009, p. 238.
943 CEG, *Forward looking estimates of the equity premium*, A report for the Joint Industry Associations, January 2009, p. 23.
944 AER, *Final decision, WACC parameters*, May 2009, p. 44.

The AER considers that a MRP of 6.5 per cent may therefore be generous when accounting for current prevailing conditions.

That said, the AER considers that, while there is evidence to suggest that the MRP may be returning to the AER's previous best estimate, at this point in time there appears to be insufficient information to justify a departure from the MRP defined in the SORI. However, the AER will continue to monitor financial market conditions and will re-evaluate its position for the final decision.

MRP estimates

Officer and Bishop suggested due to the recent increase in volatility of the equity markets that forward-looking approaches may be more appropriate than historical approaches.[945] The AER has previously noted concerns relating to the inverse relationship between the short-term fluctuations in historical excess returns and the short-term forward-looking MRP. For example, the significant decline in the equity market in 2008 resulted in a reduction of the average of historical excess returns, while estimates suggested by forward looking approaches increased. Subsequently, the AER noted the impact of excluding 2008 from historical estimates by examining estimates which excluded 2008 in the WACC review. That said, the AER continued to place significant weight on historical estimates which provided a reasonable range of MRP estimates (from 5.7 to 7.2 per cent) using numerous sampling periods.[946]

The AER has examined the analysis provided by Officer and Bishop and CEG, which examined other methods and information which may demonstrate the MRP is higher than 6.5 per cent. The question before the AER is whether this analysis represents persuasive evidence for departing from a MRP of 6.5 per cent set in the SORI. Overall, the AER considers the estimated MRPs provided by Officer and Bishop, and CEG are highly sensitive to the inputs and assumptions used to derive them. Therefore, the AER considers that the estimates derived from implied volatilities and DGMs provide limited information towards an appropriate estimate of the MRP.

The AER notes CEG and Officer and Bishop examined the increase in the DRP from 2008 and question whether the increase is driven by an increase in the debt betas or the MRP (under the CAPM framework). Officer and Bishop concluded that it is unlikely that the debt betas have more than doubled since 2006.[947] However, the AER notes a cause of the GFC is due to the collapse of credit default swaps and the debt markets. Therefore, it is possible that debt betas along with the MRP have increased in the short-term. The AER considers it difficult to disaggregate the impact on the debt beta and the MRP and also notes that the DRP is beginning to drop below the peaks experienced in 2008.

Officer and Bishop have used the implied volatilities of the ASX200 Index call option to demonstrate the MRP over 2010 to 2015 is above 6.5 per cent. The AER has a number of observations and concerns with this approach.

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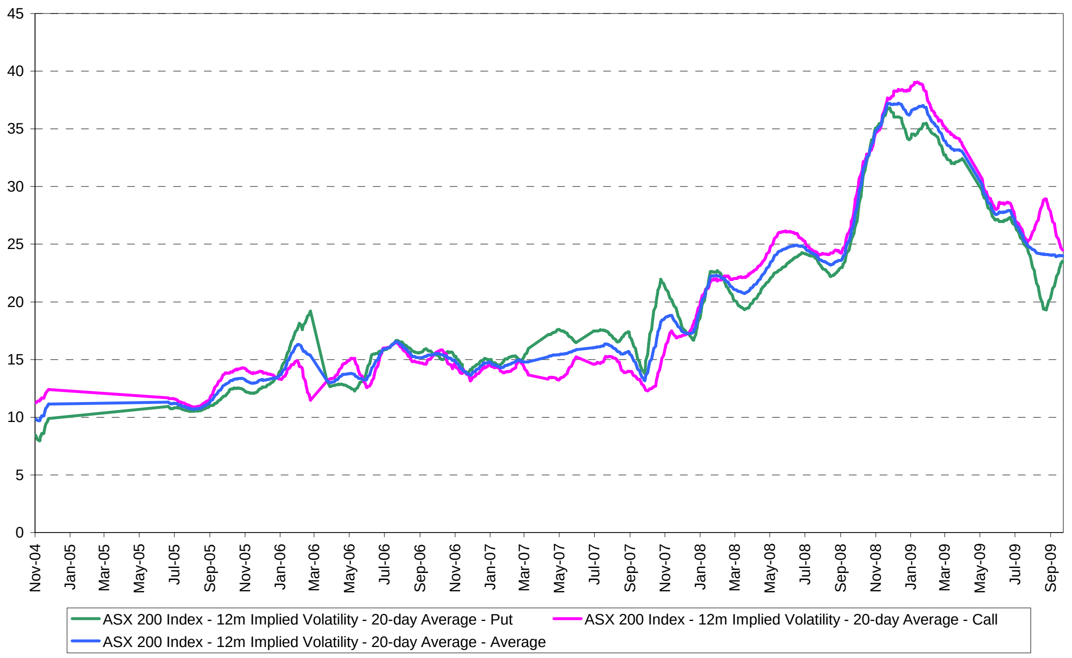
945 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 3.

946 AER, *Final decision, WACC parameters*, May 2009, pp. 237–238.

947 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, pp. 13–14.

First, Officer and Bishop examined the implied volatilities of the ASX200 Index call options (of 30.5 per cent) to demonstrate an estimate of a 12-month MRP is currently 14.2 per cent.[948] The AER has obtained implied volatilities of the ASX200 Index options and as shown in figure 11.1, it appears the implied volatilities of the ASX200 Index is returning back to historical levels (using an averaging period length of five years consistent with ETSA Utilities' regulatory proposal).

Figure 11.1: Implied volatilities ASX 200 Index options



Source: Bloomberg, AER analysis[949]

The AER notes Figure 11.1 demonstrates that implied volatility levels have fallen since the historical highs of late 2008 and below 30 per cent in April. It appears that the 12-month call option implied volatility is approaching 20 per cent and would therefore imply that an estimate of the 12-month MRP of 11.4 per cent (in 2009) which in contrast to the 14.2 per cent estimate used by Officer and Bishop.[950]

Another assumption used in Officer and Bishop's calculation of an average estimate of the MRP is that it reverts to the MRP adopted in the SORI of 6.5 per cent as the mean to which the current MRP will return to in the medium to long term. The AER observes that a limited justification has been given why mean reversion to 6.5 per cent (based on the SORI value) is more appropriate than 6 per cent, given that 6 per cent is considered by the AER as observed long-term historical average MRP.

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948 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 11.

949 A 20 day moving average has been used for illustrative purposes. However, the AER considers that it may be more appropriate to use an implied volatility based upon the same averaging period as the risk–free rate.

950 The value of 12.2 is calculated as follows, 0.5 × 24.4 = 12.2 per cent. The value of 24.4 is calculated using a simple average of the 12-month implied volatility of call options for the ASX200 Index from 16 September 2009 to 13 October 2009.

Officer and Bishop also used a number of different mean reversion paths to arrive at different geometric averages to estimate a MRP. The AER observes two different paths have been relied upon (instant mean reversion in year three or a gradual reversion beginning in year three) to derive the range of 8 to 11.8 per cent.[951] The AER consider it is difficult to judge whether one approach is more appropriate than the other, other than to observe that instant mean reversion results in the lowest estimate.

The AER notes Officer and Bishop have not provided any reasons for selecting the implied volatility of call option to estimate a forward-looking MRP. It is not clear to the AER whether the implied volatility from a put option, call option or an average taken from both options would be more appropriate.

Officer and Bishop stated the MRP estimate of 14.2 per cent is comparable to the five-year average of 14.6 per cent taken from CEG's DGM analysis.[952] The AER considers that it is inappropriate to draw comparisons between the two as:

- the 14.2 per cent (Officer and Bishop's) estimate of the MRP in 2010 (in Officer and Bishop's report) is based upon a three-year glide path, starting in 2009, to 6.5 per cent in 2012
- the CEG estimate is based upon a five-year average that assumes the MRP estimated in 2009 (year zero in Officer and Bishop's report) glides down to 6 per cent in 2016 (effectively year seven in Officer and Bishop's report).

The AER finds it difficult to draw any conclusions about the reasonableness of estimates from either the DGM analysis or the implied volatility analysis based upon the comparison made by Officer and Bishop. Not only have both approaches been estimated using different techniques, but also the estimates have:

- different year one MRPs (14.2 per cent compared to 23.2 per cent)
- different equilibrium MRPs (6.5 compared to 6 per cent)
- different glide path lengths (three-years compared to seven-years)
- differing periods that do not overlap (2010 compared to 2011 to 2016).

Finally, as already discussed, for the purposes of consistency within the CAPM, the term of the MRP must match with the term of the nominal risk–free rate. Officer and Bishop's MRP is taken from an average (or term) of five years rather than ten years. Officer and Bishop's estimate of a 8 per cent MRP (that is, five-year MRP) is then applied by ETSA Utilities in its regulatory proposal to an estimate of a ten year nominal risk–free rate. By combining a five–year MRP with a ten year nominal risk–free rate, the return on equity proposed by ETSA Utilities regulatory proposal does not represent an estimate of a five or ten year return. The AER notes that the CAPM requires that the term of the nominal risk–free rate and the MRP match for the

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951 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 11.
952 CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, p. 19.

purposes of consistency. The AER considers that the approach suggested by Officer and Bishop is inappropriate as the term of the nominal risk–free rate and the MRP do not match.

The AER reiterates that due to refinancing risk and the NER requirement that the same nominal risk–free rate term be used in the cost of debt, a forward-looking estimate based upon a 10-year term may be more appropriate. Subsequently, the AER considers that for the purposes of consistency within the CAPM, a geometric mean (or estimate) of the MRP taken over 10 years period would be more appropriate to match with the estimate of the nominal risk–free rate.

The AER considers that the concerns it has identified with the implied volatility estimation technique need to be addressed before this approach can be given more weight in informing a MRP which satisfies the underlying criteria. That said, similar to the DGM analysis, the AER considers it is highly likely that estimates derived from this approach are likely to be highly sensitive to the assumptions used. Therefore, even if a number of these issues are addressed, caution must be taken when interpreting results from the implied volatility approach.

The AER notes CEG advocated the use of a DGM over other methods of estimating a MRP.[953] Officer and Bishop also refer to CEG's DGM analysis and note Bloomberg's MRP forecasts based upon DGM analysis.[954] The AER observes that a number of assumptions have been used to derive estimates of the MRP in CEG's analysis, including:

- an adjustment to the ASX200 Index to account for 19 companies in the sample having incomplete forecasts
- an adjustment to the dividend forecast of one month to ensure that dividends paid evenly over FY2009 such that average time to remaining dividends is one month
- dividend forecasts are adjusted for imputation credits using a gamma of 0.65 (as determined in the SORI)
- long-run dividend growth rates (historical economic growth or index linked CGS) and the RBA's mid inflation target rate are used to adjust dividends into future years
- the risk–free rate of 10-year CGS sampled across the period from which the forecasts are derived will hold in perpetuity.

The AER has examined the model provided by CEG and makes the following observations:

953 CEG, *MRP and risk–free rate proxy, A report for ETSA*, 26 June 2009, pp. 14–15.
954 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, pp. 13–14.

- after 2009, it appears that dividends are paid in January of each year rather than per financial year, as 2010 is discounted by seven rather than 12 months (no reason is provided for this adjustment)
- the dividend growth model only models dividends for 125 years rather than being a perpetuity model
- long-run average growth rates have been applied to dividends while short-run average 10-year CGS have been applied in providing estimates of the MRP (that is, discount rate less the average 10-year CGS yield), the AER considers given the model is meant to be a perpetuity model that a long-run average is more appropriate.

While the AER considers all DGM estimates have limitations, the AER has amended CEG's inputs in the DGM provided to adjust for what the AER considers to be the particular short comings of CEG's approach. The AER notes that these amendments result in the range of forward-looking MRP estimates ranging from 6 to 7.8 per cent (using average 10-year CGS yields from Bloomberg – April 1991 to August 2009, resulting in a risk–free rate of 6.9 per cent compared to 4.9 per cent).[955] This result may demonstrate that a MRP of 6.5 per cent is appropriate in prevailing conditions and is in stark contrast to CEG's results of the MRP ranging from 8.3 to 16.7 per cent. That said, the AER considers it is appropriate to place limited weight upon estimates of forward-looking MRPs based upon DGM analysis, given the sensitivity of the results produced by such models to the assumptions adopted in the model. This is especially the case as there can be a large divergence in the results depending on the inputs used (that is, the long-run average compared to a short-run average risk–free rate) which are largely affected by the assumptions made under each approach.

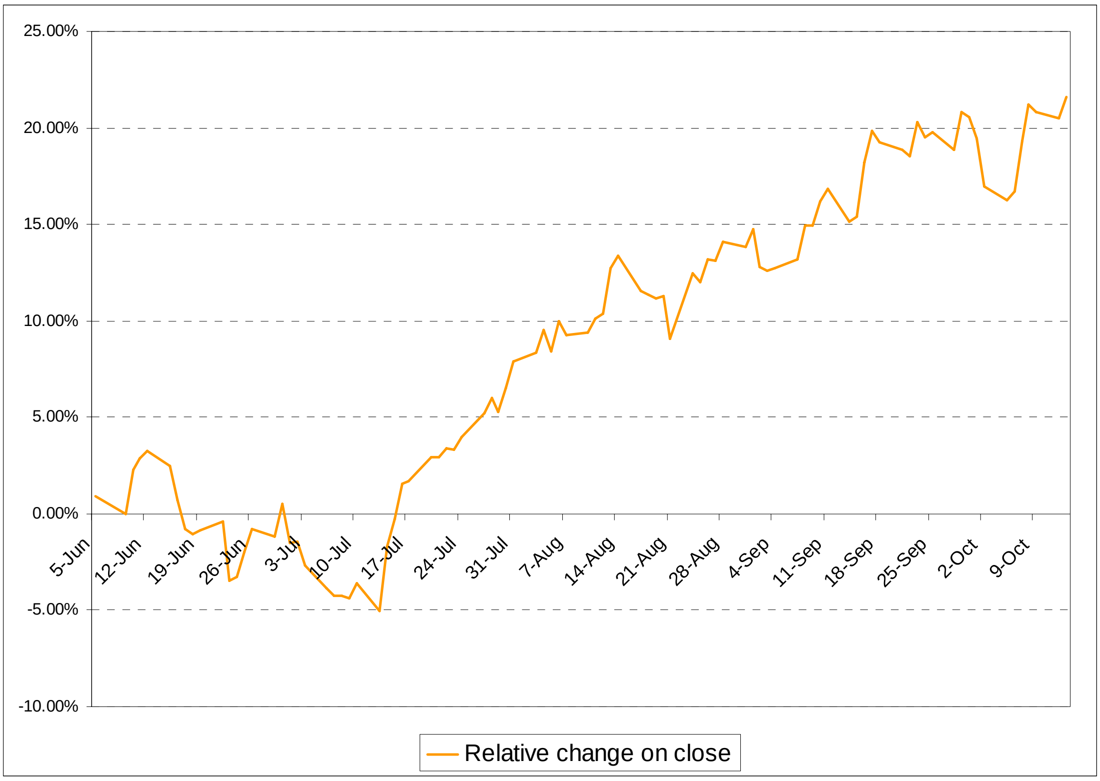
Further, although it may be likely that Bloomberg does not adjust for the value of imputation credits in its DGM forecasts, the AER observes Officer and Bishop quoted a MRP estimate of 4.6 per cent for June 2009.[956] The AER considers it is also unclear whether Bloomberg has made similar adjustments to 19 companies in its DGM analysis, as CEG did in its analysis. That said, the AER considers that it is likely the difference can be only partially be explained by the inclusion of imputation credits and adjustments to 19 companies in the sample, and it is likely that Bloomberg used different assumptions when conducting its DGM analysis. This further reflects the sensitivity of DGM analysis to assumptions used in the model.

Another factor that is worth noting when considering the sensitivity of DGM analysis to changes in the inputs is the stock prices themselves. The AER notes the relative change in the ASX200 Index from 4 June 2009 to 13 October 2009, shown in figure 11.2.

[955] There is an inverse relationship between the MRP and the risk–free rate, therefore, the higher the risk–free rate in the return on equity, the lower the MRP.

[956] R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 13.

Figure 11.2: Relative change in ASX 200 Index close - April 2009 to August 2009



Source: Bloomberg[957]; and AER analysis.

As can be seen from figure 11.2 the ASX200 Index had increased in value by over 21.6 per cent from 4 June 2009 (where CEG conducted its DGM analysis) to 13 October 2009. The AER notes the increase in stock prices result in lower dividend yields and, subsequently, lowers the implied cost of equity (as the value of stocks has increased relative to the value of dividends). The AER considers the improvement in the stock market is likely to result in a change in the return on equity underlying the DGM analysis and the MRP. That said, it also likely that dividend forecasts have improved which have a countervailing affect on the cost of equity and subsequently the estimated MRP derived from DGM analysis. The AER considers that the differences between Bloomberg and CEG's estimates, the increase in stock prices since June 2009, the use of short or long-term averages and the increase in share prices demonstrate that DGM can be quite volatile. Therefore, the AER also considers that it would be difficult to place a significant weight on MRPs estimated using DGM analysis.

The AER has analysed the new information provided by ETSA Utilities and its consultants. The AER notes that CEG, and Officer and Bishop updated their analysis with data subsequent to WACC review, and also raised issues previously addressed in the WACC review.

The AER considers there is a significant amount of uncertainty relating to the use of DGM analysis, examining debt market premiums and implied volatility analysis to

957 ASX200 Index – Historical closing value – 1 April 2009 to 13 October 2009, 14 October 2009.

form any views solely on these approaches. The AER also considers ETSA Utilities and its consultants have not addressed concerns raised by the AER during WACC review about the unreliability of MRP estimates derived from DGM analysis. It appears to the AER only minor methodological changes have been applied and the data has been updated. However, the AER considers that these changes do not address the sensitivity of estimates to assumptions used in DGM analysis.

The AER observes recent indications of improvement in financial markets and prevailing conditions compared to the prevailing conditions considered in the WACC review. The AER notes the OECD and the RBA consider that financial markets have began to stabilise, and this is also reflected in the improved conditions since the WACC review and market conditions on which ETSA Utilities' consultants have relied (up to June 2009). This is clearly demonstrated by the recent downward trend in implied volatility and the upward trend in the ASX200 Index.

The AER considers the information provided in support of ETSA Utilities' regulatory proposal does not constitute persuasive evidence for justifying a departure from a MRP of 6.5 per cent. In forming its view the AER has considered the information provided by interested parties in response to the MRP determined in the SORI and considered it against the underlying criteria. The AER considers a MRP of 8 per cent, as proposed by ETSA Utilities:

- would result in a rate of return to be 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 NEO
- has 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 MRP of 6.5 per cent set in the SORI inappropriate.

AER conclusions

The AER considers that ETSA Utilities' regulatory proposal and supporting information from its consultants do not provide persuasive evidence to depart from the MRP of 6.5 per cent set in the SORI. The AER considers:

- the ACCC did explicitly consider imputation credits in forming its view about the MRP
- for internal consistency with the CAPM, the term of which the MRP is measured must be consistent with the term of the nominal risk–free rate
- the appropriate period to consider the impact of prevailing conditions on the MRP for ETSA Utilities is 2010 to 2020
- it has not received any persuasive evidence that the financial conditions have worsened from the 15-year outlook (2009 to 2024) of the WACC review rather it appears financial conditions have improved (as reflected by the OECD, the RBA and the ASX200 Index)

- it has concerns over the assumptions and approach used in the implied volatility analysis by Officer and Bishop, hence while the resulting estimates were considered, they were afforded little weight in the AER's considerations

- it is appropriate to place limited weight upon estimates of forward looking MRPs based upon DGM analysis, given the sensitivity of the results produced by such models to the assumptions.

The AER considers the information provided in support of the regulatory proposal does not constitute persuasive evidence for justifying a departure from a MRP of 6.5 per cent. In forming its view the AER has considered the information provided by interested parties in response to the MRP determined in the SORI and considered it against the underlying criteria. The AER considers:

- that ETSA Utilities has 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 MRP of 6.5 per cent set in the SORI inappropriate

- there is a significant amount of uncertainty relating to the use of DGM analysis, examining debt market premiums and implied volatility analysis to form any views solely on these approaches

- there is evidence that the state of financial markets has improved since the WACC review.

11.5.4 Equity beta

The equity beta measures the standardised correlation (or covariance) between the returns on an individual risky asset or business with that of the overall market. In essence, it represents the 'riskiness' of the business compared with that of the market. Risk results from the possibility that returns for the business will differ from expected returns (the greater the uncertainty around the returns of a business, the greater its level of risk).

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.[958]

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.

Regulatory requirements

The SORI specifies an equity beta of 0.8.[959]

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[958] 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, GDP growth, interest rates, commodity prices, foreign exchange rates and changes in tax laws.

The AER considers the underlying criteria relating to the NER requirements that are of particular relevance to determine the equity beta are:[960]

- 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
  - having regard to the economic costs and risks of the potential for under and over investment.

ETSA Utilities regulatory proposal

ETSA Utilities proposed to adopt the parameter specified in the SORI for the equity beta.[961]

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

959 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009, p. 7.
960 NER, clause 6.5.4(e); and NEL, Part 1, section 7A.
961 ETSA Utilities, *Regulatory proposal*, July 2009, p. 246.

- 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.[962]

AER conclusion

The equity beta of 0.8 proposed by ETSA Utilities 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.[963] The underlying criteria used by the AER in its SORI in relation to the credit rating level were:

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962 NER, clause 6.5.4(e).

963 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, which are:[964]

  - 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.

ETSA Utilities Regulatory Proposal

ETSA Utilities proposed an indicative DRP of 4.7 per cent, noting that this figure will be updated for the final determination with data from the agreed averaging period. ETSA Utilities accepts 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.[965] In support of its proposal, ETSA Utilities submitted reports from CEG and the Victorian DNSPs.

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:[966]

> 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;

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964 NEL, Part 1, section 7A.

965 ETSA Utilities, *Regulatory proposal*, 1 July 2009, p. 245

966 CEG, *Estimating the cost of 10 year BBB+ debt: A report for ETSA, Ergon and Energex*, June 2009, p. 16.

> 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:[967]

> 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:[968]

- 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

- 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.

The Victorian DNSPs' report was included by ETSA Utilities to give further weight to their argument of the underestimation of Bloomberg estimates. This report was submitted to the AER in June 2009 as part of consultation on the AMI roll out in Victoria.[969] This report examined the AER's approach to measuring the DRP in previous regulatory determinations, which relied on data from Bloomberg. The DNSPs concluded that this approach was not suitable for the purposes of setting the DRP with regard to conditions prevailing at the time of the measurement period prescribed for the AMI WACC period.[970] The DNSPs instead recommended the use

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967 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 16.
968 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 65.
969 Victorian DNSPs, *Debt risk premium for use in the initial AMI WACC period*, 1 June 2009.
970 Victorian DNSPs, *Debt risk premium for use in the initial AMI WACC period*, 1 June 2009, pp. 1–2.

of the Tabcorp 5 year BBB+ rated bond with an adjustment to reflect the requirement for a 10 year term structure.

Submissions

ETSA Utilities submitted further information to support its proposal which included a memorandum from Doctor Tom Hird of the CEG (CEG Memorandum).[971] The CEG Memorandum provided no new arguments but rather gave further weight to the arguments developed in the CEG report. Generally, the CEG memorandum noted the observed underestimation of the Bloomberg methodology and the lack of data utilised by the AER in its process of analysis in setting the DRP.[972]

Issues and AER considerations

Arguments regarding the robustness of methods employed by Bloomberg and CBASpectrum, with respect to producing data for the DRP, have been previously raised and considered by the AER (as well as other regulators).[973] Over this time, service providers, as well as their advisors, have argued for both Bloomberg and CBASpectrum.[974] In response to these proposals and arguments, the AER has examined the performance of estimates derived from both data sources against relevant market data.[975] 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.

More recently 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.[976] 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

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971 Doctor Tom Hird also authored the CEG report.

972 Hird, T., *Memorandum: Data relevant to assessing the cost of debt*, 28 August 2009.

973 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.

974 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 ACG, *'A' rating Debt Margin differential between Bloomberg and CBA Spectrum (Memorandum)*, 23 February 2006.

975 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.

976 IPART, *Estimating the debt margin for the weighted average cost of capital*, May 2009.

and will not be developed in time for this determination. Therefore, at present the 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 ETSA Utilities' regulatory proposal (including its consultants' reports) in the context of the AER's previous considerations on this issue, specifically in regard to:

- credit rating level
- the Victorian DNSPs' report
- 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 ETSA Utilities 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 for 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.[977]

The Victorian DNSPs report

ETSA Utilities refers to the Victorian DNSPs' report regarding:[978]

> …that the current benchmark estimates from Bloomberg materially underestimate the yield on a BBB+ corporate bond.

The AER disagrees with the Victorian DNSPs that Bloomberg estimates materially underestimate the yield on the benchmark corporate bond. The AER notes that the arguments put forward by the Victorian DNSPs are considered at a more general level by CEG, and are addressed by the AER below.[979] The AER's considerations of the Victorian DNSPs' report can be seen in the AER's AMI review draft and final determinations.[980]

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":[981]

> 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.

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977 NER, clause 6.5.4(e).

978 ETSA Utilities, *Regulatory Proposal*, July 2009, p. 245.

979 Victorian DNSPs, *Debt risk premium for use in the initial AMI WACC period*, 1 June 2009.

980 See AER, *Victorian advanced metering infrastructure review: 2009–11 AMI budget and charges applications, draft determinatio*n, July 2009; and AER, *Victorian advanced metering infrastructure review: 2009–11 AMI budget and charges applications, final determination*, October 2009.

981 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 4.

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" is 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.

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 and subsequent CEG memorandum 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. This argument is supported further in the CEG Memorandum. 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[982]
- is reliant on relatively scarce or in some instances a singular observation[983], does not consider the use of bonds with other credit ratings[984] and excludes bonds that would have resulted in a higher fair value curve[985]

[982] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 21–22.
[983] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 23–27.
[984] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 46.
[985] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 20–21.

- is not consistent with financial theory as it creates fair value curves that across maturities are not smooth[986], spreads to CGS that decrease for some long term maturities[987] and fair value estimates decreased as a result of the global financial crisis[988]

- does not reflect the current market conditions due to its bias toward liquid corporate bonds where the current market is "characterised by illiquidity"[989]

- is not transparent in its level of discretion and judgement used to create fair value curves.[990]

CEG concluded that Bloomberg's performance against the criteria is poor and: [991]

> 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[992]

- relies on a broader range of observations including higher yielding bonds and bonds from other appropriate credit ratings for determining fair value curves[993]

- creates fair value curves that across maturities that are smooth and upward sloping[994] as well as fair value estimates that did increase in response to the global financial crisis[995]

- better reflects the current market conditions of illiquidity in the market through the inclusion of illiquid corporate bonds.[996]

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.[997]

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986 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 33–37.
987 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 28–31.
988 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 49–51.
989 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 22.
990 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 45.
991 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 65.
992 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 46–48.
993 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 40–44, 47.
994 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 41–44, 47.
995 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 49–52.
996 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 47–48.
997 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 17–18.

Against the other 'desirable' criteria, CEG noted that both Bloomberg and CBASpectrum methodologies have advantages as they are independent to the regulatory proceedings.[998]

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.[999] 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 argument is supported in the CEG Memorandum and is the approach ETSA Utilities put forward in its regulatory proposal.

The AER does not accept CEG's proposed criteria for selecting a data source to derive the benchmark DRP.[1000] 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.[1001]

CEG confirmed this by stating:[1002]

> 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

[998] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 66.
[999] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, pp. 65–66.
[1000] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 16.
[1001] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 18.
[1002] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 42.

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 Economic Consulting (NERA) have previously suggested the use of Bloomberg fair yield estimates as more reliable than those of CBASpectrum.[1003] 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 AMI determination, CEG make an interesting point:[1004]

> 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 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.[1005] 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:[1006]

> 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

[1003] NERA, *Critique of Available Estimates for the Credit Spread on Corporate Bonds: A report for the ENA*, May 2005, p. 2.
[1004] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 61.
[1005] 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.
[1006] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 56.

of the average BBB+ bond yield'[1007] 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.[1008] 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:[1009]

> 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…

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.[1010] 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).[1011] 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[1012] 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.[1013] The factual errors raised by CEG include:[1014]

[1007] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 56.
[1008] AER, *Victorian advanced metering infrastructure review: 2009–11 AMI budget and charges applications, final determination*, October 2009, pp. 126-128.
[1009] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 16.
[1010] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 66.
[1011] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 66.
[1012] AER, *Final Decision, NSW DNSPs*, 28 April 2009.
[1013] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 63.

- 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 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:[1015]

> 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.[1016]

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'.[1017] 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

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1014 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 63.
1015 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 63.
1016 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 64.
1017 CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 64.

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.[1018]

The CEG memorandum provides further discussion into this issue particularly in relation to the selection of bonds (four BBB+ bonds) the AER used in its analysis. The CEG memorandum notes that the AER's conclusion that Bloomberg fair value estimates are the most accurate predictor of yield estimates is determinant on the sample size and sources used in the analysis. The CEG memorandum tests this analysis by utilising variations to the AER chosen sample of bonds from different sources. The CEG memorandum concluded that:[1019]

> If all yield estimates on A rated bonds are included then there is a unanimous result that the average of Bloomberg and CBASpectrum (being the higher fair value estimate) is the best predictor…

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 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.

[1018] CEG, *Estimating the cost of 10 year BBB+ debt*, June 2009, p. 64.
[1019] Hird, T., *Memorandum: Data relevant to assessing the cost of debt*, 28 August 2009, point 27.

Therefore, the analysis in the CEG memorandum is flawed as it incorporates bonds that do not meet these criteria.

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.[1020] The AER accordingly considers that given the 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,[1021] 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 ETSA Utilities, 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 a simple 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:

$$WSSE = \frac{1}{n}\sum_{i=1}^{n}\left\{\left[\sum_{j=1}^{t_i}\left(Observed_{i,j} - Fair_{i,j}\right)^2\right]\frac{1}{t_i}\right\}$$

Where:

- n is the number of bonds in the sample
- t_i is the number of observations for the i^{th} bond

[1020] AER, *Final Decision, ACT DNSP*, 28 April, pp. 99–101.
[1021] AER, *Final Decision, ACT DNSP*, 28 April, and AER, *Final Decision, NSW DNSPs*, 28 April 2009.

- $Observed_{i,j}$ 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 11.3.

Table 11.3: Population of BBB+ rated bonds

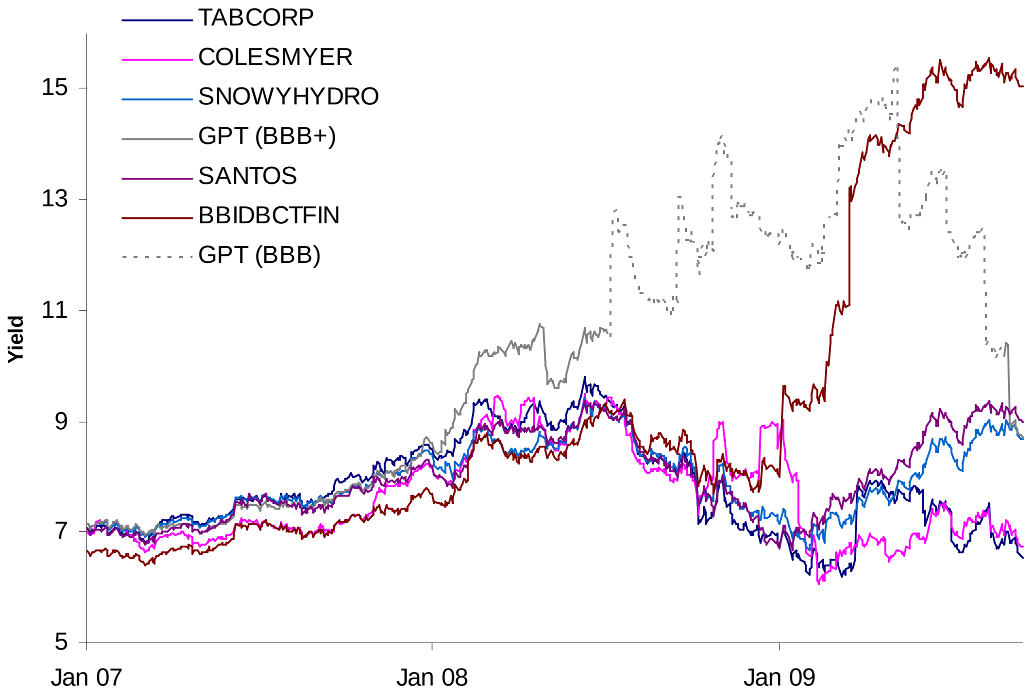
Issuer	Maturity	ISIN
Tabcorp	13 October 2011	AU300TPP0010
Coles Myer	25 July 2012	AU300CML1014
Snowy Hydro	25 February 2013	AU000SHL0034
GPT Group	22 August 2013	AU300GPTM218
Santos	23 September 2015	AU300ST50076
Babcock & Brown Infrastructure	9 June 2016	AU300BBIF018

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 11.3 shows the observed yields from a population of the BBB+ bonds.

Figure 11.3: 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 these periods present some indication of a structural break. This is the period leading up to the downgrade of the GPT Group 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.[1022]

[1022] Chow, G. C., *Tests of Equality Between Sets of Coefficients in Two Linear Regressions*, Econometrica 28(3), July 1960.

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.[1023] 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.[1024] 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 11.4 and table 11.5 over both 15 and 18 days to 13 October 2009. These yields were observed from Bloomberg, CBASpectrum and UBS.

Table 11.4: 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 Group	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.

Table 11.5: Sample of BBB+ corporate bonds—observed yields and fair values over 18 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	7.5	7.1
Coles Myer	6.9	6.8	6.8	7.7	7.7
Snowy Hydro	8.9	10.4	8.9	8.0	8.1
GPT Group	9.0	8.8	8.9	8.2	8.4
Santos	8.8	9.0	9.1	8.8	9.0

Source: Bloomberg, CBASpectrum, UBS rate sheets and AER analysis.

1023 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.

1024 Babcock and Brown, *Suspension from official quotation*, 12 January 2009.

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 11.6 and table 11.7.

Table 11.6: 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.

Table 11.7: Fair value and observed yield analysis using weighted sum of squared errors over 18 days to 13 October 2009

		Observed yield source		
		Bloomberg	**CBASpectrum**	**UBS**
Fair Value Source	Bloomberg	0.6	1.6	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.

The AER considers that over both the 18 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 ETSA Utilities 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 with respect to ETSA Utilities' averaging period. 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 4.29 per cent.

11.5.6 Overall cost of capital

Regulatory requirements

The NEL provides that the AER must, in performing or exercising an AER economic regulatory function or power perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the NEO.[1025] Given that this decision relates to a regulatory proposal, the AER must also consider the revenue and pricing principles in the NEL. The AER considers that the following principles appear directly relevant to the cost of capital:[1026]

- providing a service provider with a reasonable opportunity to recover at least efficient costs (principles 7A(2))
- providing a service provider with effective incentives to invest efficiently (principle 7A(3))
- having regard to the economic costs and risks of under and over investment (principle 7A(6)).

As part of the SORI, when examining the overall cost of capital, the AER considered:

[1025] NEL,section 16(1).
[1026] NEL, Part 1, section 7A.

- whether the WACC is set at a level expected to be sufficient to incentivise efficient investment in electricity network infrastructure, while not set too high so as to incentivise inefficient overinvestment in electricity network infrastructure

- whether prevailing conditions around the time of the regulatory decision required a departure from the previously adopted values (based upon empirical evidence from the debt and equity markets)

- the relationships between each of the parameters, with respect to:

  - the methodology used to examine empirical evidence with respect to WACC parameters (such as the benchmarks efficient network service provider and the selection of comparator businesses)

  - consistency between the parameters with respect to term structure, valuation of excess returns (the valuation of gamma and the MRP) and other inter-linkages.

Issues and AER considerations

As noted in section 11.4, the COTA and the SACOSS specifically identified revenue impacts arising from ETSA Utilities' proposed increase in the cost of capital.[1027] In forming a view on the overall WACC, the AER must exercise its power in a manner that will or is likely to contribute to the achievement of the NEO. The NEO requires the AER to not only consider the consumer impacts of increases in prices (brought about by higher allowed revenues) but also other impacts in terms of the quality, safety and the reliability of supply. The AER notes it position in the WACC review recognised this and stated:[1028]

> …in relation to the rate of return, is that the WACC be set at a level expected to be sufficient to incentivise efficient investment in electricity network infrastructure, while not set too high so as to incentivise inefficient overinvestment in electricity network infrastructure. The AER considered that if it determined values and methods for individual WACC parameters that produce an overall regulatory rate of return that is expected to achieve this outcome, then the AER will have exercised its power in a manner that will or is likely to contribute to the achievement of the NEO. In doing so, the AER also considered that, in respect of each parameter, it would have also had regard to the need to achieve an outcome which is consistent with the NEO.
>
> and
>
> …based on detailed analysis of the available evidence from submissions and expert consultants, and considered in the context of all the relevant issues facing electricity NSPs, the AER expected that its proposed parameters would continue to provide incentives for efficient network investment in the long term interests of electricity consumers...
>
> and
>
> … the AER considers that the rate of return provided in this final decision is sufficient to attract investment to the sector over the long term. While

[1027] SACOSS, *Submission to the AER*, 28 August 2009, p. 3; and COTA, *ETSA distribution price review*, 27 August 2009, p. 5.
[1028] AER, *Final decision, WACC parameters*, May 2009, pp. 12, 14 and 49.

> cognisant of current conditions in debt and equity markets, the AER has taken a longer term perspective in setting rates of return over the period 2010–2019.

The AER continues to consider that the position taken in the WACC review with respect to individual parameters is likely to result in an overall cost of capital outcome that meets the NEO (which includes the consideration of the impact on prices).

The AER has identified when forming views on the WACC the need for a holistic approach. This can not only be demonstrated by examining the overall WACC outcome but also the linkages between WACC values, methods and the credit rating level in both this decision and the WACC review. The AER notes there are three main sources for these links:

- theoretical issues and assumptions made (for example: gamma and the MRP, term of debt; and hedging and debt raising costs)
- rule requirements (for example: the NER defining that the nominal risk–free rate for the return on equity is to be the same as the nominal risk–free rate for the cost of debt)
- consistency in approaches to obtaining benchmarks on industry specific parameters.

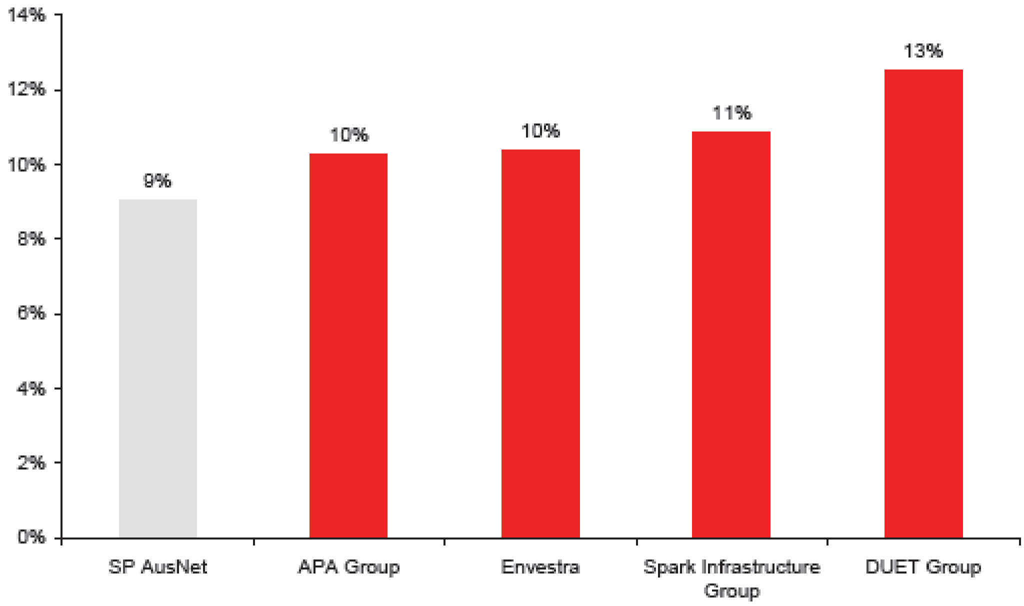
In forming its views on ETSA Utilities' regulatory proposal, the AER has noted that any departures from the parameters set in the SORI may result in the need to adjust other parameters (or forecast opex amounts where relevant). For example, if the MRP were to be based upon a 5-year average or a 5-year risk–free rate, then the methodology used to determine the nominal risk–free rate would have to be adjusted to reflect this five-year period.

The AER observes that, similar to the WACC review, interested parties have identified the impact of the GFC and need for a holistic approach as important considerations. The WACC review was undertaken at the height of the GFC and was considered extensively by the AER and stakeholders generally. Throughout this decision, the AER has considered the impacts of prevailing conditions which are still influenced by the GFC. In particular, the AER has considered (in section 11.3.3) whether it is appropriate to set a forward-looking MRP above the long-run point of equilibrium based upon prevailing conditions.

The AER notes that the forward-looking estimate is determined by the period of time debt and equity is assumed to be held. Specifically, this is driven by the term of the nominal risk–free rate which carries the same definition across the return on equity and the cost of debt in the SORI. Using the same example as before, if the MRP was set solely on prevailing conditions, a MRP above 6.5 per cent may be appropriate. However, the AER considers a MRP above 6.5 per cent is unlikely to reflect a forward-looking MRP. Therefore, the AER considers when examining appropriate WACC parameters there is not only need to examine prevailing conditions (such as the impact of the GFC) but also the need to provide a forward-looking cost of capital.

Further, the AER considers that the return on equity provided by the values, methods and credit rating level defined in the SORI (including a MRP of 6.5 per cent) is sufficient to promote efficient investment in electricity services. The AER notes that, based upon an 18-day averaging period ending 13 October 2009, that the return on equity implied by the SORI values and methods is 10.57 per cent, which increases to 11.80 per cent if a long term average is used.[1029] The AER observes that these figures sit well within investors' expectations of equity yields for regulated energy businesses.

Figure 11.4: Regulated utilities FY10 — forecast yields



Source: Macquarie Equities Research[1030]

The AER also notes that if it were to accept the proposed MRP of 8 per cent, the resulting return on equity would be 11.77 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 are currently unregulated activities and therefore are likely to attract a higher return on equity than other regulated utilities.[1031] 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.

AER conclusions

The AER still considers that the approach taken in the WACC review and subsequently in this decision is likely to result in outcome that provides for outcome that meets the NEO (which includes the consideration of the impact on prices).

[1029] Average nominal risk–free rate of 6.60 per cent calculated using interpolated annualised CGS yields, using an averaging period from 1 July 1992 to 13 October 2009.

[1030] Macquarie Research, *SP AusNet—No surprise expected at 1H10*, 21 October 2009, p. 7.

[1031] DUET, *Asset portfolio overview*, DUET Group, < http://www.duet.net.au/duet/asset-portfolio/index.html>, Accessed on: 28 October 2009.

Throughout this decision the AER has considered the impacts of prevailing conditions at the time of this decision. However, this has been tempered by the need for the WACC to represent a forward-looking estimate. The AER notes that the forward-looking estimate is by and large determined by the term or period of time it is assumed debt and equity is held.

11.5.7 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 determined[1032] that a method that is likely to result in the best estimate of inflation over a 10-year period is to apply the RBA's short-term inflation forecasts—currently extending out to two years—and adopt the mid–point of its target inflation band beyond that period (that is, 2.5 per cent) for the remaining eight years. An implied 10-year forecast is derived by a geometric average of these individual forecasts.[1033]

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.

The ACT distribution determination final decision stated:

> … a forecast inflation rate over a 10–year period using the RBA's inflation forecasts for the first two years and the mid–point of the RBA's target inflation range for the remaining eight years. The AER considered that, consistent with the draft decision, this methodology provides the best estimate of a 10–year inflation forecast to be applied in the post–tax revenue model.[1034]

ETSA Utilities regulatory proposal

ETSA Utilities has adopted the approach used by the AER in the NSW and ACT distribution determinations for determining the inflation rate.[1035]

[1032] AER, *Final decision, ACT DNSP*, 28 April 2009, p. xxi; and AER, *Final decision, NSW DNSPs*, 28 April 2009, p. xxxviii.

[1033] 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.

[1034] AER, *Final decision, ACT DNSP*, 28 April 2009, p. xxi.

[1035] ETSA Utilities, *Regulatory Proposal*, July 2009, p. 237.

Issues and AER 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.[1036] 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 number of index-linked CGS being traded in the market has decreased, which has increased the likelihood that the market for these securities is a poorly functioning market. Therefore, any analyses which use the Fisher equation technique are 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. The RBA has not issued any new indexed linked CGS 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.[1037] This has been confirmed with announcement that an indexed-linked treasury bond has been issued by the AOFM on 8 October 2009.[1038] The AER considers that, while the yields 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 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.[1039] Based on this approach and using the latest

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[1036] NER, clause 6.4.2(b)(1).

[1037] AOFM, Treasury indexed bonds – resumption of issuance and participation in syndicate, Operational notice, <http://www.aofm.gov.au/content/notices/15_2009.asp>, accessed 27 August 2009.

[1038] 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.

[1039] 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.

RBA forecasts as shown in table 11.8, an inflation forecast of 2.45 per cent produces the best estimate for a 10 year period.[1040]

Table 11.8: AER 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

ETSA Utilities has adopted the approach used by the AER in the NSW electricity distribution determination for determining the inflation rate. Consistent with this determination, the AER accepts ETSA Utilities' proposed approach under clause 6.4.2(b)(1) of the NER.

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 parameter 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 ETSA Utilities 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.

For this draft decision, the AER has determined a nominal vanilla WACC of 10.02 per cent for ETSA Utilities, which is slightly higher than that proposed by ETSA Utilities. This difference is due to an increase in the nominal risk–free rate since ETSA Utilities submitted its regulatory proposal. The impact of the increase in the nominal risk–free was partly offset by maintaining a MRP of 6.5 per cent.

[1040] The AER notes that this will be updated to incorporate the latest available data at the time of the final decision.

Table 11.9 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 its final determination.

Table 11.9: AER conclusion on WACC parameters

Parameter	
Nominal risk–free rate	5.37%
Real risk–free rate	2.85%
Expected inflation rate	2.45%
Gearing level (Debt/Equity)	60:40
Market risk premium	6.5%
Equity beta	0.80
Debt risk premium	4.29%
Nominal pre–tax return on debt	9.66%
Nominal post–tax return on equity	10.57%
Nominal vanilla WACC	10.02%

11.7 AER draft decision

In accordance with clause 6.12.1(5) of the NER, the rate of return to apply to ETSA Utilities is 10.02 per cent.

12 Service target performance incentive scheme

12.1 Introduction

This chapter discusses the AER's application of its national service target performance incentive scheme (STPIS) to ETSA Utilities in the next regulatory control period.[1041]

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 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 has two broad components, the s–factor, and the Guaranteed Service Levels (GSL) scheme. The s–factor comprises 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

[1041] The AER published its national STPIS on 26 June 2008 (Version 01). On 8 May 2009, the AER published an amended STPIS (Version 01.1) addressing material issues regarding the interaction between the cap on revenue at risk and the equation for the calculation of the s–factor, and to clarify how the scheme operates. On 25 November 2009 the AER published a further amended STPIS (Version 1.2) 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.[1042]

The AER is required to publish a framework and approach paper prior to every distribution determination which, amongst other things, requires the AER set out its likely approach to the application of an STPIS.[1043] Although the STPIS is mandatory, its application may be varied by the AER as described in its framework and approach paper for the relevant DNSP. The DNSP may also propose to vary the application of the scheme, to the extent that such variation is allowed for in the STPIS, and provided that it can demonstrate that such variation is consistent with clause 6.6.2(b)(3) of the NER.

Under clause 2.1(d) of the STPIS the AER is required to determine the following in accordance with the implementation of the STPIS:

(1) each applicable component and parameter to apply to a DNSP including the method of network segmentation for the reliability of supply component

(2) the revenue at risk to apply to each applicable component and parameter

(3) the incentive rate to apply to each applicable parameter including the value of customer reliability (VCR) to be applied in accordance with clause 3.2.2(d) and appendix B

(4) the performance target to apply to each applicable parameter in each regulatory year of the regulatory control period

(5) any decision with respect to the transitional arrangements set out in clause 2.6

(6) the threshold to apply to each applicable GSL parameter

(7) the payment amount to apply to the applicable GSL parameter

(8) the major event day boundary to apply to a DNSP:

[1042] NER, clause 6.6.2(b), note.
[1043] NER, clause 6.8.1.

(i) where the DNSP has proposed a major event day boundary that is greater than 2.5 standard deviations from the mean; or

(ii) where the major event day boundary that applied to the DNSP in previous distribution determinations was greater than 2.5 standard deviations from the mean; or

(iii) where the DNSP has proposed a major event day boundary that is greater than 2.5 standard deviations from the mean and where in previous distribution determinations the major event day boundary that has applied to the DNSP was greater than 2.5 standard deviations from the mean.

12.3 AER framework and approach

The AER published its framework and approach for ETSA Utilities in November 2008.[1044] The purpose of the AER's framework and approach is to assist the DNSP to prepare its regulatory proposal.

In its framework and approach for ETSA Utilities, the AER stated that it would apply the STPIS to ETSA Utilities for the next regulatory control period. The AER stated that its STPIS would replace ESCOSA's Service Incentive Scheme, but would operate in conjunction with the service standards framework (SSF) and the GSL scheme administered by ESCOSA.[1045]

The AER also stated that it would apply the reliability of supply and customer service components and parameters of the STPIS, set out in table 12.1 to ETSA Utilities in the next regulatory control period.[1046]

Table 12.1: ETSA Utilities – applicable parameters for the STPIS

Component	Network segment
Reliability of supply	
SAIDI	CBD feeders
	Urban feeders
	Short rural feeders
	Long rural feeders
SAIFI	CBD feeders
	Urban feeders
	Short rural feeders
	Long rural feeders
Customer service	
Telephone answering	All of network

Source: AER, *Framework and approach paper: Application of schemes - ETSA Utilities*, November 2008, p. 76.

[1044] AER, *Final framework and approach paper, ETSA Utilities*, November 2008.
[1045] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 76.
[1046] AER, *Final framework and approach paper, ETSA Utilities*, 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 ETSA Utilities. The STPIS performance targets would be established at or above the current SSF levels established by ESCOSA. The momentary average interruption frequency index (MAIFI) parameter would not be applied to ETSA Utilities as the AER did not consider that the sampling method used in ETSA Utilities' reporting of MAIFI provided a suitable basis of performance measurement for a financial incentive such as the STPIS.[1047]

In relation to the customer service component, the AER stated in the framework and approach paper that it would apply the telephone answering parameter in the next regulatory control period to ETSA Utilities.[1048]

The STPIS does not currently include any quality of supply parameters. Consistent with the STPIS, the AER's preliminary position was that the GSL component of the scheme would not apply to ETSA Utilities in the next regulatory control period as it is currently subject to a jurisdictional GSL scheme.[1049]

12.4 ETSA Utilities regulatory proposal

Although the STPIS is mandatory, its application may be varied by the AER. The DNSP 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.

ETSA Utilities proposed that the AER apply a STPIS subject to the following changes:

- total rewards or penalties for the reliability of supply component be capped at ±5 per cent of revenue (±0.5 per cent for customer service)[1050]
- a different statistical method be used for determining the major event day (MED) boundary under the STPIS, namely the Box–Cox transformation method[1051]
- a modified s–bank mechanism should apply[1052]
- an alternative reporting method be used.[1053]

ETSA Utilities stated that it did not have five years of data available for setting performance targets for the reliability parameters and therefore proposed that these targets be based on the four years of available data.[1054]

1047 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 77.
1048 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 77.
1049 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 59, 76.
1050 ETSA Utilities, *Regulatory proposal*, July 2009, p. 212.
1051 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 212–216.
1052 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 216–217.
1053 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 217–218; Note: In its letter of 25 September 2009 ETSA Utilities withdrew this proposal.

ETSA Utilities noted that the AER may not be able to allow the Box–Cox transformation and the modified s–bank under Version 01.1 of the STPIS as these variations were not allowed for (or contemplated) in the STPIS. As such it proposed that the AER amend the STPIS to include these variations to enable its proposal to be adopted in the distribution determination.[1055] Subsequent to ETSA Utilities submitting its regulatory proposal, the AER published Version 01.2 of the STPIS which permits DNSPs to propose an alternative methodology for the purpose of transforming its data into a normal distribution.[1056]

12.5 Submissions

The AER received three submissions commenting on the application of the STPIS to ETSA Utilities.

The Council on the Ageing (COTA) submitted that customers are not prepared to pay for greater reliability of supply and therefore ETSA Utilities should not justify price increases on the willingness of customers to pay for more reliable service.[1057]

Business SA submitted that the STPIS may result in incentives for ETSA Utilities to invest in improving services where it can be done cheaply even though the improved services may not be required.[1058]

The Energy Consumers Coalition of South Australia (ECCSA) submitted that if ESCOSA's settings are a minimum then the AER should set performance targets at a more onerous level.[1059] The ECCSA added that ETSA Utilities has proposed targets which are readily achievable and it has possibly already outperformed and that the AER should impose challenging targets.[1060]

12.6 Consultant review

On behalf of the AER, PB was required to undertake a review of any changes to the STPIS that ETSA Utilities may have 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:[1061]

- 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

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1054 ETSA Utilities, *Regulatory proposal*, July 2009, p. 213.
1055 ETSA Utilities, *Regulatory proposal*, July 2009, p. 217.
1056 AER, *Final decision, Electricity distribution network service providers, Service target performance incentive scheme,* November 2009.
1057 COTA, *ETSA distribution price review*, 27 August 2009, p. 3.
1058 Business SA, *Submission to the AER*, August 2009, p. 4.
1059 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 46.
1060 ECCSA, *ETSA Utilities application, a response*, August 2009, p. 48.
1061 PB, *Report – ETSA Utilities*, October 2009, pp. 6–7.

- 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.

From this review, PB has provided its recommendations of appropriate reliability of supply and customer service performance targets to be applied to ETSA Utilities over the next regulatory control period.

PB's recommendations in relation to ETSA Utilities' reliability of supply parameters are as follows:[1062]

- the quality of ETSA Utilities' data on past performance is suitable for setting targets

- the four years of performance data available is sufficient to inform the setting of targets, which should be set at the average of the four years to June 2009

- the Box–Cox transformation provides a more accurate normalisation of the available data and should be adopted to calculate the MED boundary for ETSA Utilities.

PB's recommendations in relation to ETSA Utilities' customer service parameter are as follows:[1063]

- the quality of ETSA Utilities' data is suitable for setting targets

- the targets should be set at the average of the four years of performance to 2008–09, which is 88.7 per cent.

PB also recommended that ETSA Utilities' proposed modified s–bank mechanism should not be applied.[1064]

12.7 Issues and AER considerations

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 over that provided by the capex and opex allowances.

For the purpose of forecasting expenditure ETSA Utilities proposed to maintain its level of service performance in line with the standards set by ESCOSA which are

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1062 PB, *Report – ETSA Utilities*, October 2009, pp. 175–176.
1063 PB, *Report – ETSA Utilities*, October 2009, p. 174.
1064 PB, *Report – ETSA Utilities*, October 2009, p. 176.

based on average historical performance.[1065] The AER notes that performance targets under the STPIS are also based on average historical performance.[1066]

PB considered that the proposed expenditure to maintain these levels of performance is prudent and efficient.[1067] ETSA Utilities did not propose any other expenditure to fund changes or improvements in service performance.

The AER is satisfied that ETSA Utilities 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 that under the reliability of supply component, targets would be set for both SAIDI and SAIFI, with financial incentives attached to each. Further, the AER stated ETSA Utilities' network would be divided into four feeder types (CBD, urban, short rural and long rural).[1068]

The AER also stated that the telephone answering customer service parameter (as defined in appendix A of the STPIS) would apply to ETSA Utilities in the next regulatory control period.[1069]

The AER did not propose to include any quality of supply parameters, however the AER stated it would monitor ETSA Utilities' quality of supply performance as reported to ESCOSA, and explore the desirability of including quality of supply parameters in the STPIS in future regulatory control periods.[1070]

The AER stated it would not apply the GSL component of the STPIS in the next regulatory control period as ETSA Utilities will be subject to a jurisdictional GSL scheme administered by ESCOSA. The AER stated that if at any time in the next regulatory control period ESCOSA ceases to apply a GSL scheme, the AER's likely approach is to apply the GSL component of the STPIS from the date the jurisdictional scheme is withdrawn.[1071]

The AER notes that ETSA Utilities 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.

The AER will adopt the approach set out in the framework and approach paper to apply the SAIDI and SAIFI reliability of supply parameters and the telephone answering customer service parameter. There are no quality of supply parameters to apply. The components and parameters of the STPIS applicable to ETSA Utilities are as set out at table 12.1.

[1065] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 207–208.
[1066] AER, *Final decision, Electricity DNSPs STPIS,* November 2009, clause 3.2.1(a).
[1067] PB, *Report – ETSA Utilities,* October 2009, p. 170.
[1068] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 76.
[1069] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 76–77.
[1070] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 76–77.
[1071] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 76.

12.7.3 Revenue at risk

Framework and approach

The AER stated that a default maximum revenue increment or decrement would apply for the STPIS, excluding GSL components, of ±3 per cent of total revenue for each regulatory year. Within this cap, the STPIS provides that the maximum revenue at risk for individual customer service parameter is ±0.5 per cent.[1072]

ETSA Utilities regulatory proposal

ETSA Utilities proposed that total rewards or penalties under the STPIS be capped at ±5 per cent of revenue (±0.5 per cent for customer service). This is consistent with Version 01.1 of the STPIS although different to what was set out in the framework and approach paper and in Version 01.0 of the STPIS.[1073]

Submissions

Business SA noted that the STPIS has the potential to inflate prices as it provides for a reward of up to five per cent (noting also there is the potential for a penalty of up to five per cent). Business SA submitted that this may result in incentives for ETSA Utilities to invest in improving services where it can be done cheaply even though the improved services may not be required and thereby customers may not benefit from these incentives.[1074]

AER considerations

A key element of the incentive properties of the STPIS is the overall cap on revenue at risk from the potential rewards and penalties provided for under the scheme. The STPIS allows for the AER to vary the revenue at risk where this would satisfy the objectives of the scheme.

ETSA Utilities' proposed revenue at risk is consistent with Versions 01.1 and 01.2 of the national STPIS but different to that set out in the AER's framework and approach paper. The AER considers that because of the adjustment to the carry forward mechanism made in Version 01.1 of the STPIS, ETSA Utilities' proposal to apply a cap on revenue at risk of ±5 per cent is broadly consistent with the power of the incentive set out in Version 01.0 on which the framework and approach paper was based.

However, as discussed at section 12.7.7, the AER will allow ETSA Utilities to adopt the Box–Cox data transformation method in calculating the MED boundary. The AER notes that in setting the revenue at risk it must take into account the benefits to consumers that are likely to result from the scheme, in particular, that the benefits are sufficient to warrant any reward or penalty under the scheme for DNSPs. Given that the MED outcome may reduce the focus of the scheme by excluding events which could be under ETSA Utilities' control, the application of a lower powered scheme in this instance will reduce the risk of ETSA Utilities being inappropriately rewarded. The AER considers that this approach is consistent with the objectives of the scheme.

[1072] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 77.
[1073] ETSA Utilities, *Regulatory proposal*, July 2009, p. 212.
[1074] Business SA, *Submission to the AER*, August 2009, p. 4.

The AER notes Business SA's concerns regarding the potential for prices to be inflated under the STPIS by five per cent. The AER notes that the highest reward or penalty issued to date under a jurisdictional s–factor style scheme is 2.6 per cent of revenue.[1075] The AER considers that at ±5 per cent the cap on revenue at risk is unlikely to be reached. In any event, the AER notes that the consequence of the lower cap on revenue at risk for ETSA Utilities is that there is less potential for the STPIS to inflate prices.

The AER notes PB's advice that it is not aware of any matters that would limit the revenue at risk to ±3 per cent and recommended that the current STPIS limit of ±5 per cent be applied.[1076] However, as discussed, in this instance, the AER considers that a lower powered scheme is more consistent with the objectives of the STPIS, given the uncertainty over the MEDs.

The AER does not consider that this approach will adversely impact the incentives on ETSA Utilities to implement non–network alternatives.

Accordingly, in regard to ETSA Utilities' proposal to apply a cap on revenue at risk of ±5 per cent the AER is not satisfied that this is consistent with the objectives of the STPIS or clause 6.6.2(b)(3) of the NER. The AER considers it appropriate to maintain the approach set out in the framework and approach paper. Accordingly the AER will apply a cap on revenue at risk of ±3 per cent to ETSA Utilities 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 this is consistent with the STPIS. As the AER has determined to apply a cap on overall revenue at risk of ±3 per cent, the AER proposes to apply a cap to the revenue at risk of ±0.3 per cent for the telephone answering customer service parameter for ETSA Utilities.

12.7.4 Incentive rates

In its framework and approach paper the AER proposed to adopt the incentive rates as set out in the STPIS, although the AER stated that for the purpose of the distribution determination for ETSA Utilities it would also have regard to the most recent value of customer reliability (VCR) study.[1077] [1078]

Submissions

The COTA stated that there is evidence that customers are not prepared to pay for greater reliability of supply. The COTA submitted that ETSA Utilities should not justify revenue and price increases on the basis that customers are willing to pay more for reliable service.[1079]

[1075] This was applied as a penalty to SP AusNet in 2002 and in 2004 under the Essential Services Commission of Victoria's service performance incentive scheme in Victoria. AER, *Final decision, Electricity DNSPs STPIS*, May 2009, p. 9.

[1076] PB, *Report – ETSA Utilities,* October 2009, p. 176.

[1077] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 70.

[1078] The CRA VCR study had only just been commissioned when the framework and approach paper was written.

[1079] COTA, *ETSA distribution price review*, 27 August 2009, p. 3.

AER considerations

Clause 6.6.2(b)(3) of the NER stipulates that the AER must take into account the willingness of the customer to pay for improved service performance. The incentive rates in the STPIS are based on measures of customers willingness to pay, specifically, the value that customers place on supply reliability, referred to as the VCR.

The AER notes the COTA stated that customers were not willing to pay for service improvements. The AER considers that customers' willingness to pay varies with customer demographics (for example, type of consumer, location, economic) and with a customer's expectations which largely depend on whether they are currently receiving poor or good performance. Hence, it is difficult to obtain an aggregate indication of customers' willingness to pay that can be applied broadly across a distribution network.

In its framework and approach paper, the AER considered that the 2008 Charles River Associates (CRA) Report was the most recent robust study of reliability incentive rates.[1080] In setting VCR values CRA takes into account the 2003 KPMG Report which assessed customers' willingness to pay.[1081]

KPMG used statistical techniques to ascribe willingness to pay values to particular service quality parameters. KPMG addressed a number of service characteristics, including the frequency and duration of supply interruptions, consumer service parameters, such as whether customers are currently receiving good or poor performance, and characteristics of the distribution service.[1082]

The AER was satisfied that this was a robust study of customers' willingness to pay. The AER is therefore satisfied that the VCR values determined by CRA, on which the incentive rates in the STPIS are based, reflect customers' willingness to pay.

Under clause 3.2.2(d) of the STPIS a DNSP can propose an alternative VCR. ETSA Utilities did not propose any variation to the VCR or incentive rates set out in the framework and approach paper. Accordingly, the AER will calculate the incentive rates for the reliability of supply parameter for the next regulatory control period in accordance with clause 3.2.2 and appendix B of the STPIS. As set out in the framework and approach paper, an incentive rate of –0.040 per cent will apply to ETSA Utilities telephone answering parameter, consistent with clause 5.3.2(a)(1) of the STPIS.[1083] These parameters are set out at table 12.2. The incentive rates have been calculated using the ratios of energy consumption forecasts by network type, provided by ETSA Utilities in its regulatory proposal.

[1080] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 15.
[1081] KPMG, *Consumer preferences for electricity service standards*, 2003. Cited in AER, *Proposed, Electricity distribution network service providers service target performance incentive scheme*, April 2008.
[1082] KPMG, *Consumer preferences for electricity service standards*, 2003, p. 21.
[1083] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 60.

Table 12.2: ETSA Utilities incentive rates 2010–15

Parameter	Incentive rate
Reliability of supply component	
SAIDI	
CBD	0.0099
Urban	0.0550
Short-rural	0.010
Long-rural	0.0123
SAIFI	
CBD	0.9018
Urban	4.5787
Short-rural	1.1577
Long-rural	1.7147
Customer service component	
Telephone answering parameter	–0.0400

Source: AER analysis, ETSA Utilities, email response, ETSA utilities reliability data, 26 September 2009.

12.7.5 Transitional arrangements

There are no specific transitional arrangements as set out in clause 2.6 of the STPIS that apply to ETSA Utilities in the next regulatory control period.

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 ETSA Utilities while the GSL scheme administered by ESCOSA remains in place. If at any time in the next regulatory control period ESCOSA ceases to apply a GSL scheme, the AER's likely approach is to apply the GSL component of the STPIS from the date the jurisdictional scheme is withdrawn.[1084]

The AER will not apply the GSL component of the STPIS to ETSA Utilities in the next regulatory control period while the GSL scheme administered by ESCOSA remains in place.

12.7.7 Determining the MED boundary

The AER adopted the Institute of Electrical and Electronics Engineers (IEEE) standard for determining the MED boundary.[1085] The IEEE standard excludes natural

[1084] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 76.
[1085] AER, *Final decision, Electricity DNSPs STPIS*, November 2009, appendix D.

events which are more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years SAIDI data.[1086]

ETSA Utilities noted that its proposal for an alternative approach for determining the MED boundary may not be consistent with Version 01.1 of the STPIS. Therefore, ETSA Utilities requested an amendment to the STPIS.[1087]

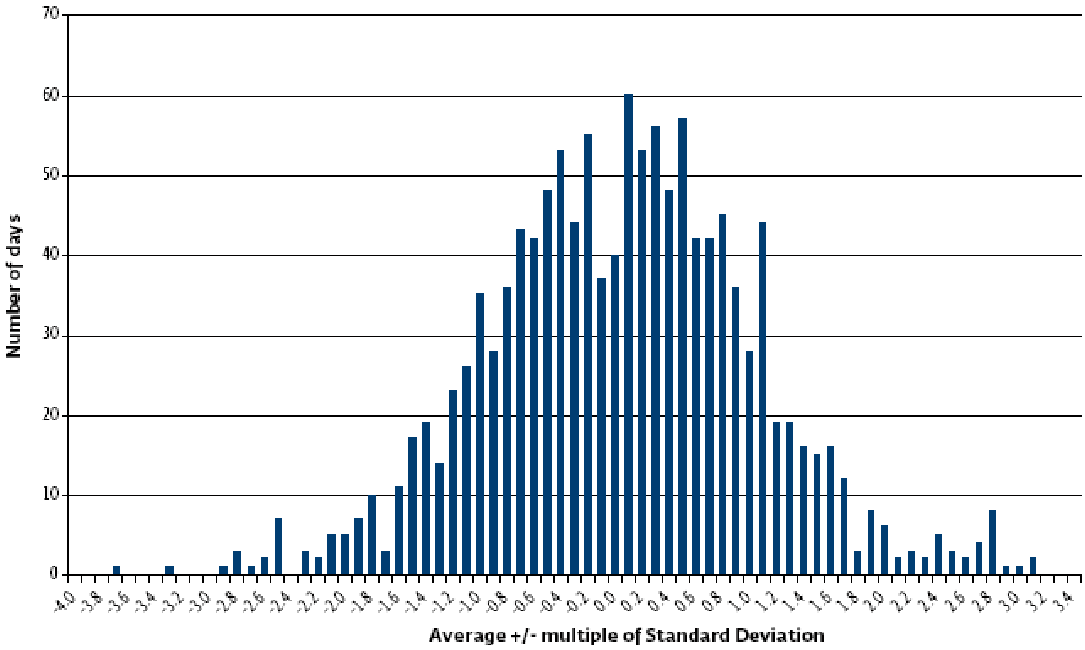
The AER agrees that an alternative transformation method is not consistent with Version 01.1 of the STPIS and therefore could only be applied if the STPIS is amended. On 21 September 2009 the AER published an amended STPIS (version 01.2) and explanatory statement, which assessed, amongst other things the potential inclusion of any recognised transformation method. Following consultation, the AER published Version 01.2 of the STPIS which allowed DNSPs to propose an alternative approach for determining the MED boundary.[1088]

Appendix D of Version 01.2 of the STPIS provides that where a statistical test of the data indicates that the data is not normally distributed, the DNSP may (subject to clause 2.2 of the STPIS) propose an alternative data transformation method which results in a more normally distributed data set.

ETSA Utilities regulatory proposal

ETSA Utilities stated that its daily SAIDI data did not transform into a normal distribution using the natural logarithm. ETSA Utilities provided the graph in figure 12.1 to demonstrate that the SAIDI data does not transform into a normal distribution.

Figure 12.1: ETSA Utilities SAIDI data



Source: ETSA Utilities, *Regulatory proposal*, July 2009, p. 215.

[1086] IEEE, *Standard 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices*, May 2004.

[1087] ETSA Utilities, *Regulatory proposal*, July 2009, p. 217.

[1088] AER, *Final decision, Electricity DNSPs STPIS*, November 2009.

ETSA Utilities engaged Dr John Field to analyse the data to assess potential options.[1089] Dr Field stated that he measured the skewness and the kurtosis of the SAIDI data produced with the natural logarithm of the data. He considered that using this method the data does not transform into a normal distribution. Dr Field stated that he also applied the Anderson–Darling test to assess the normality of the data and concluded that the data is significantly different from a normal distribution. Dr Field also applied the Box–Cox transformation to the data and tested the results in the same way. He concluded that the transformed data distribution is not significantly different from a normal distribution.[1090]

ETSA Utilities proposed the use of the Box–Cox transformation method for determining the MED boundary. ETSA Utilities noted that the natural logarithm of its SAIDI data from 1 July 2005 to 30 June 2009 results in 1.3 days per year being excluded rather than the IEEE expected outcome which resulted in 2.3 days per year being excluded.[1091]

Consultant review

PB examined ETSA Utilities available reliability data and confirmed that:

- the natural logarithm transformation method does not produce a normalised data set
- the Box–Cox transformation provides a more accurate normalisation of the available data.[1092]

PB advised that based on the four years of data provided, it calculated the MED boundary to be 4.369 minutes. If this boundary was applied, an average of 5.0 events would be excluded per year compared to 1.2 events per year if the natural logarithm transformation method was adopted. PB advised that in its experience, the number of events typically excluded by the MED boundary is between 3 and 5. PB considered that the number of events excluded by the Box–Cox transformation method appeared to be at the high end of what it would typically find and that this result may be due to only four years of data being available.[1093]

PB advised that the Box–Cox transformation method is likely to lead to outcomes more consistent with the STPIS. It also considered that the Box–Cox transformation method maintains the focus of the scheme on non–major event days.[1094]

AER considerations

The AER notes that the IEEE used the natural logarithm to convert SAIDI data into a normal distribution, which can be used to determine outliers in performance. Both

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1089 ETSA Utilities, *Regulatory proposal*, July 2009, p. 212.
1090 ETSA Utilities, *Regulatory proposal*, July 2009, p. 213.
1091 ETSA Utilities advised in its letter of 25 September 2009 that the natural logarithm transformation resulted in 1.2 events being excluded. ETSA Utilities, *Regulatory proposal*, July 2009, pp. 212–216.
1092 PB, *Report – ETSA Utilities*, October 2009, pp. 171–172.
1093 PB, *Report – ETSA Utilities*, October 2009, p. 172.
1094 PB, *Report – ETSA Utilities*, October 2009, p. 172.

ETSA Utilities (supported by Dr Field's advice) and PB concluded that, based on the available data, applying the natural logarithm method does not transform ETSA Utilities' SAIDI data into a normal distribution. The AER recognises that the natural logarithm method does not produce a normal distribution and therefore considers that it is appropriate to consider an alternative method for transforming the data.

The regulatory framework requires that the performance which is rewarded or penalised should be events over which the DNSP has significant control. If abnormal occurrences that are beyond design limits have been captured in standard performance data then these abnormalities need to be removed. The AER's preferred approach for identifying system performance is to apply a statistical methodology. This methodology is based on a DNSP's past performance which objectively differentiates system performance within the normal operational design limits and environment from infrequent low probability events that have a large detrimental effect on the network.

Dr Field advised ETSA Utilities that the Box–Cox transformation method is a suitable method for creating a normal distribution. PB also advised that the Box–Cox transformation method produces a more normally distributed data set. The AER considers that ETSA Utilities has satisfied the requirements of the STPIS to demonstrate that the data is not normally distributed. The AER considers that ETSA Utilities has also demonstrated that the Box–Cox transformation method is a suitable method by which to derive a normally distributed data set. However, the STPIS requires that in applying an alternative data transformation methodology the AER be satisfied that the objectives of the STPIS are also achieved.

The AER notes PB's findings that (based on limited Victorian, NSW and Qld data) the number of MEDs typically excluded by applying this methodology is in the range of 3 to 5 days. It also notes PB's confirmation that the log transformation of ETSA Utilities' reliability data is not normally distributed, and that the application of the Box–Cox transformation maintains the focus of the scheme on non-major event days and that the AER should accept the proposed data transformation methodology.

Applying the IEEE 2.5 beta statistical methodology to ETSA Utilities' available historical data results in a large variance in the MED outcome depending on whether natural log or Box-Cox transformation is adopted. Applying the natural log results in an average of 1.2 MED while Box-Cox results in 5.0 MEDs.

Based on PB's analysis of ETSA Utilities' data, using either methodology, results in an outcome at the high end or outside of NSW's and Queensland's typical MED range. The AER acknowledges that, in practice the annual number of MEDs will vary year on year due to weather and other factors. However, in this instance it is unclear whether the large variance is an outcome of different statistical approaches and/or limitations in the available data set, and whether either approach (natural log or Box–Cox) would result in a reasonable estimate of normal system performance. Moreover, the MED average appears to be outside of the acceptable range of MED averages the AER would expect from the DNSPs operating in the NEM. Given that ETSA Utilities' MEDs are outside of the expected range the AER is not satisfied that the days that have been classified as MEDs would have been chosen on qualitative grounds.

Given this uncertainty, the MED boundary in this case may exclude more than the infrequent, low probability events that have a large detrimental impact on the network. If this is the case, then the focus of the STPIS will not necessarily cover all of the non-major event days, with the result that greater rewards may be paid because poor, but non-major, days are excluded. Such an outcome is inconsistent with the objectives of the STPIS.

The AER notes that the STPIS was designed to provide DNSPs with incentives to maintain and improve service performance, with particular emphasis on encouraging sustainable improvement to service rather than focusing on one-off or infrequent events. Consistent with this, the purpose of specifying exclusions is to limit the risk that single very large events may result in unreasonable penalties being applied, the financial cap being reached and the scheme being suspended.[1095]

Although the AER accepts the adoption of the Box–Cox data transformation methodology as a statistical technique, given the uncertainty associated with the MED outcome under the current data set, acceptance of Box–Cox might also reduce the focus of the scheme by excluding events which are under the control of ETSA Utilities. To guard against the risk that ETSA Utilities might be inappropriately rewarded because poor but not major event days are excluded, the AER considers that the application of a lower powered scheme is reasonable.

In making this assessment, the AER notes the GSL scheme administered by ESCOSA does not exclude MEDs. Thus ETSA Utilities remains exposed to the risk of financial penalties for delay in restoration of supply in extreme outage events.

In these circumstances, the AER considers that the Box–Cox data transformation methodology in conjunction with a cap on revenue at risk of ±3 per cent will be more consistent with the objectives of the scheme.

12.7.8 s–bank

Regulatory proposal

ETSA Utilities stated that the reason for implementing the s–bank mechanism was to reduce the price variations to customers. ETSA Utilities submitted that delaying an incentive under the current s–bank mechanism by only one year will not always reduce price volatility for customers. ETSA Utilities therefore proposed that an alternative s–bank mechanism should be applied, one which allows it to either:[1096]

- defer incurring any rewards or penalties under the STPIS for more than a one year delay
- bank rewards or penalties up to a maximum percentage of its revenue.

ETSA Utilities submitted that the result of this approach will be that customers will see no variation in price when no variation in underlying reliability performance

[1095] AER, *Explanatory statement and discussion paper - Proposed STPIS*, April 2008, p. 24.
[1096] ETSA Utilities, *Regulatory proposal*, July 2009, p. 217.

occurs, that is, a DNSP will only be rewarded or penalised for sustained changes in performance.[1097]

ETSA Utilities noted that a different approach to the application of the s–bank mechanism may require an amendment to the STPIS. Therefore ETSA Utilities proposed that the AER amend the STPIS in relation to the operation of the s–bank mechanism.[1098]

Consultant review

PB provided a number of examples that demonstrated that proper application of the s–bank can reduce volatility in pricing, but it also showed it is unlikely to remove all variation in pricing where there is no underlying change in service performance.[1099]

PB considered that the modified s–bank mechanism has the characteristic of delaying the application of any revenue increment or decrement for an indefinite period. PB considered the incentive to control variations about the average is diminished and the delay will decouple changes in performance from the application of the revenue increment or decrement, weakening the incentive properties of the scheme.[1100]

PB concluded that these characteristics do not meet the objectives of the scheme as set out in clause 1.5 of the STPIS, in particular to provide an incentive to maintain and improve service performance as set out in clause 6.6.2(a) of the NER.[1101]

AER considerations

The AER agrees with ETSA Utilities that the s–bank mechanism allows a DNSP to delay a revenue increment or decrement or a portion of a revenue increment or decrement for one regulatory year, and thereby assists in reducing price volatility. However, while the s–bank mechanism does assist in reducing price volatility the AER considers that allowing rewards or penalties to carryover several years would weaken the nexus between service performance and financial rewards or penalties. This is contrary to the objective of the STPIS as it potentially reduces the incentive for DNSPs to maintain and improve service performance, given the long lag between service performance levels and rewards or penalties. Such a lag would also diminish transparency for customers with respect to how the STPIS incentives operate and how the DNSP's actual service performance compares to its performance targets.

Allowing DNSPs to bank rewards or penalties up to a maximum percentage of a DNSP's revenue could increase the risk of price volatility because once that threshold is reached the entire amount would then be applied to a DNSP's revenue via the s–factor. Further, the incentive for DNSPs to maintain and improve service performance may be reduced when the amount accumulated in the s–bank approaches either threshold.

[1097] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 216–217.
[1098] ETSA Utilities, *Regulatory proposal*, July 2009, p. 217.
[1099] PB, *Report – ETSA Utilities*, October 2009, p. 175.
[1100] PB, *Report – ETSA Utilities*, October 2009, p. 175.
[1101] PB, *Report – ETSA Utilities*, October 2009, p. 176.

The AER notes that ETSA Utilities' considered that the modified s–bank would result in rewards or penalties being applied only where there are sustained changes to performance. However, the AER concurs with PB's findings that a modified s–bank mechanism is unlikely to remove all variation in pricing where there is no underlying change in service performance.

The AER also notes that the approaches proposed by ETSA Utilities would add extra steps to the application of the s–factor. This has the potential to add to the complexity of the STPIS which also impairs the link between service performance and rewards or penalties.

The AER notes that a modification to the s–bank mechanism would require an amendment to the STPIS. The AER did not consider it appropriate to amend the STPIS in relation to the s–bank mechanism.[1102]

Overall, the AER does not consider that the approach proposed by ETSA Utilities to amend the s–bank mechanism satisfies the criteria set out at clause 6.6.2 of the NER. The AER therefore does not consider it appropriate to amend the approach set out in the STPIS.

12.7.9 Reporting method

ETSA Utilities submitted that it is inefficient to report using two slightly different methods, one for ESCOSA, and another for the AER.

ETSA Utilities stated that it currently provides monthly reliability performance data to ESCOSA on a quarterly basis. ETSA Utilities' outage management system (OMS) is used to provide this data, based on an approach of determining the SAIDI and SAIFI for each day (midnight to midnight) using the customer minutes for that day divided by the number of customers supplied by that feeder type on that day. This daily data is then summed to determine the SAIDI and SAIFI for each feeder type.[1103]

The STPIS states that for:

- SAIDI—the customer minutes should be summed over a year and then divided by the average number of customers for that year
- SAIFI—the number of customer interruptions should be summed over a year and then divided by the average number of customers for that year.

ETSA Utilities proposed that it apply the method that it uses to report to ESCOSA to report to the AER.[1104]

ETSA Utilities also noted that there is a difference between ESCOSA and the AER in relation to how abandoned calls are treated for the purpose of reporting telephone grade of service (GOS) data. ETSA Utilities submitted that it would be more efficient

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1102 AER, *Final decision, Electricity DNSPs STPIS*, November 2009.
1103 ETSA Utilities, *Regulatory proposal*, July 2009, p. 218.
1104 ETSA Utilities, *Regulatory proposal*, July 2009, pp. 217–218.

to apply the same method and therefore, proposed that it apply the method that it uses to report to ESCOSA to report to the AER.[1105]

ETSA Utilities informed the AER that ESCOSA indicated that it will allow ETSA Utilities to use the same reporting method for reliability performance as prescribed in the STPIS.[1106] Accordingly, ETSA Utilities provided the data to the AER in accordance with the method set out in the STPIS.

The AER considers it appropriate that ETSA Utilities provide this data to the AER, consistent with the national approach.

12.7.10 Performance targets

ETSA Utilities historical data and average performance for each of the parameters is set out at table 12.3.

Table 12.3: ETSA Utilities' average of historical service performance for reliability

	2004–05[a]	2005–06	2006–07	2007–08	2008–09	Average
SAIDI						
CBD	–	27.5	24.2	23.6	33.0	27.1
Urban	–	128.4	106.0	92.4	90.7	104.4
Short rural	–	170.1	214.7	159.7	191.4	184.0
Long rural	–	260.1	309.5	265.3	245.8	270.2
SAIFI						
CBD	–	0.250	0.315	0.236	0.251	0.263
Urban	–	1.530	1.362	1.173	1.102	1.292
Short rural	–	1.912	1.794	1.457	1.782	1.736
Long rural	–	2.046	2.353	2.063	1.981	2.111

Notes: (a) Data not available as ETSA Utilities only implemented OMS and started recording with this system from 1 July 2005.

The AER stated in its framework and approach paper that targets will reflect available data on past performance of ETSA Utilities' network with adjustments as necessary under the STPIS.[1107]

Regulatory proposal

ETSA Utilities proposed to set targets for the reliability parameters based on four years of data to 2008–09. In the current regulatory control period, ETSA Utilities has

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1105 ETSA Utilities, *Regulatory proposal*, July 2009, p. 218.
1106 ETSA Utilities, letter to the AER, 25 September 2009, p. 1.
1107 AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 59, 77.

used manual reliability reporting processes for reporting against and establishing reliability targets. These manual processes only collect and report on high voltage interruptions, and do not incorporate any data from low voltage interruptions. ETSA Utilities considered that it is not possible to apply any meaningful transformation on the manual data to make it comparable to the OMS data. As a consequence, ETSA Utilities proposed to establish the reliability targets for the next regulatory control period on the average performance as reported by the OMS for the period 1 July 2005 to 30 June 2009 (that is, four years of data).[1108]

Submissions

The ECCSA set out certain standards of reliability which it stated that ESCOSA has determined that ETSA Utilities will be required to meet for the next regulatory control period. The ECCSA submitted that if ESCOSA's settings are a minimum then the AER should set performance targets at a more onerous level.[1109]

The ECCSA stated that ETSA Utilities would have outperformed the new targets in every measure in the latest full year. The ECCSA submitted that ETSA Utilities has proposed targets which are readily achievable and that the AER should impose targets that are challenging such that any reward is the result of investment from ETSA Utilities. The ECCSA further submitted that the indicative targets should be at least ten per cent lower (more onerous) than proposed by ETSA Utilities.[1110]

Consultant review

PB noted that the STPIS requires that targets be based on the previous five years of reliability performance. As ETSA Utilities considered that it was only able to provide four years of data, PB analysed whether four years of data was sufficient to set targets. As part of its analysis PB requested information about the external factors that drive reliability performance (weather) and historical variability about the average. PB also examined ETSA Utilities' reliability data based on the older manual process for the eight year period to 2007–08.[1111]

PB's analysis confirmed that the variability in reliability that can be seen in the four years of data provided (up to 2008–09) is consistent with the variability in the longer term data. PB therefore concluded that the four years of performance data was sufficient to set targets.[1112]

PB's recommended performance targets for the performance incentive scheme are as set out at table 12.3.

AER considerations

Under clause 3.2.1 of the STPIS, performance targets are based on an average of the previous five years of data. However where five years of data is not available, clause 3.2.1(c) allows the AER to approve an alternative methodology or benchmark provided it is consistent with the objectives set out in clause 1.5 of the STPIS.

[1108] ETSA Utilities, *Regulatory proposal*, July 2009, p. 213.
[1109] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 46.
[1110] ECCSA, *ETSA Utilities application, a response*, August 2009, p. 48.
[1111] PB, *Report – ETSA Utilities*, October 2009, p. 172.
[1112] PB, *Report – ETSA Utilities*, October 2009, p. 172.

The AER accepts PB's view that ETSA Utilities does not have five years of suitable data available to establish performance targets because of the change from a manual reporting system to OMS. On that basis, the AER considers it is appropriate to consider whether an alternative methodology or benchmark is appropriate.

The AER considers that PB has conducted a robust assessment of ETSA Utilities available data. PB concluded that the variability in reliability that can be seen in the four years of data is generally consistent with the longer term data. PB recommended that four years of data is sufficient to use for the purpose of setting targets. On that basis, the AER considers that it is appropriate to establish ETSA Utilities' performance targets based on four years of data.

The AER notes the ECCSA concerns that ETSA Utilities has proposed indicative targets for SAIDI and SAIFI which are greater than those recorded in 2007–08. In 2007–08, ETSA Utilities outperformed its target that it proposed for the next regulatory control period (the lower the number for SAIDI or SAIFI the better the service performance).

The AER considers that this scenario is not unexpected under the STPIS, since performance targets are based on the average of the previous five years of performance.[1113] While performance targets are able to be adjusted for planned reliability improvements and other factors, ultimately the performance targets are based on an average of performance in previous years. As such it is possible that a DNSP may have outperformed the performance targets at some stage previously.

The ECCSA has also commented on the relationship between levels of service expected by ESCOSA and the operation of the STPIS. ESCOSA currently operates a GSL scheme and SSF. The STPIS was designed to operate in conjunction with jurisdictional based average and minimum service level schemes and GSL schemes. The STPIS will only reward ETSA Utilities if its actual service performance is better than its performance targets. Under the SSF ETSA Utilities is only required to 'maintain service levels'.[1114] As there is no incentive under the SSF to improve service standards, the AER is satisfied that the STPIS does not allow ETSA Utilities to receive a benefit for meeting targets it is required to meet under the SSF.

Accordingly the AER considers that the approach proposed by ETSA Utilities to set performance targets based on four years of available data satisfies the criteria that the AER must consider in approving an alternative methodology or benchmark under clause 3.2.1(c) of the STPIS. The AER has not amended the performance targets proposed by ETSA Utilities. The performance targets to apply to ETSA Utilities in the next regulatory control period are as set out at table 12.4.

[1113] AER, *Final decision, Electricity DNSPs STPIS,* November 2009, clause 3.2.1(a).
[1114] ETSA Utilities, *Regulatory proposal*, July 2009, p. 38.

Table 12.4: AER performance targets for ETSA Utilities for the next regulatory control period

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
CBD	minutes	27.1	27.1	27.1	27.1	27.1
Urban	minutes	104.4	104.4	104.4	104.4	104.4
Short rural	minutes	184.0	184.0	184.0	184.0	184.0
Long rural	minutes	270.2	270.2	270.2	270.2	270.2
SAIFI						
CBD	per 0.01 interruptions	0.263	0.263	0.263	0.263	0.263
Urban	per 0.01 interruptions	1.292	1.292	1.292	1.292	1.292
Short rural	per 0.01 interruptions	1.736	1.736	1.736	1.736	1.736
Long rural	per 0.01 interruptions	2.111	2.111	2.111	2.111	2.111
Customer service						
Telephone answering	percentage	88.7	88.7	88.7	88.7	88.7

12.8 AER conclusion

The AER has determined that it will apply the STPIS to ETSA Utilities 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 ETSA Utilities' regulatory proposal, PB's report, submissions and has had regard to clause 6.6.2(b) of the NER. The AER has concluded that:

- it will apply the SAIDI and SAIFI reliability of supply parameters and the telephone answering customer service parameter. There are no quality of supply parameters to apply. The components and parameters of the STPIS applicable to ETSA Utilities are as set out at table 12.1
- a cap on overall revenue at risk of ±3 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
- a cap on revenue at risk of ±0.3 per cent for the telephone answering customer service parameter will apply in accordance with clause 5.2(b) of the STPIS
- it will apply the incentive rates for the next regulatory control period in accordance with clause 3.2.2 and appendix B of the STPIS, as set out in table 12.2

- an incentive rate of –0.040 per cent will apply to ETSA Utilities 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 ETSA Utilities while the GSL scheme administered by ESCOSA remains in place. If at any time in the next regulatory control period ESCOSA ceases to apply a GSL scheme, the AER will apply the GSL component of the STPIS from the date the jurisdictional scheme is withdrawn

- the AER will apply the Box–Cox transformation method to ETSA Utilities to set the MED boundary in the next regulatory control period. This method satisfies the criteria set out at clause 2.2 and appendix D of the STPIS

- the approach proposed by ETSA Utilities to amend the s–bank mechanism does not satisfy the criteria set out at clause 6.6.2 of the NER

- it is appropriate that ETSA Utilities provide reliability data and telephone GOS data to the AER, consistent with the definition set out in the STPIS

- the approach proposed by ETSA Utilities to set performance targets based on four years of available data satisfies the criteria that the AER must consider in approving an alternative methodology under clause 3.2.1(c) of the STPIS

- the performance targets proposed by ETSA Utilities in the next regulatory control period are consistent with clause 3.2.1(a)(1) and are as set out at table 12.4.

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 ETSA Utilities 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 and the telephone answering customer service parameter

2. overall revenue at risk of ±3 per cent and ±0.3 per cent for the telephone answering parameter

3. the incentive rates to apply to each applicable parameter will be calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of the STPIS, and are set out in table 12.2 of this draft decision

4. the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period as set out at table 12.4 of this draft decision

5. the GSL component will not apply while ESCOSA's GSL scheme remains in place. In the event that ESCOSA'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 ETSA Utilities. An 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 ETSA Utilities from 1 July 2010.[1115]

In its framework and approach paper, the AER decided that its likely approach for ETSA Utilities' distribution determination would be to apply the national EBSS in the next regulatory control period.[1116] However, the scheme will not have a direct financial impact on ETSA Utilities until the 2015–20 regulatory control period when it will receive carryover benefits/penalties for efficiency gains or losses made 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

Clause 9.29.5(c) of the NER provides that the AER's application of an EBSS to ETSA Utilities for the next regulatory control period must be consistent with the Statement of Regulatory Intent issued by ESCOSA on March 2007 (ESCOSA

1115 AER, *Final decision, Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008.

1116 AER, *Final framework and approach paper, ETSA Utilities*, November 2008.

SORI).[1117] The ESCOSA SORI contains transitional arrangements relating to the efficiency carryover mechanism (ECM) which has applied to ETSA Utilities in the current regulatory control period.[1118]

The ESCOSA SORI does not limit the AER's discretion in formulating its own EBSS, or in applying it to ETSA Utilities. It is transitional in nature, and requires the AER to apply carryovers accumulated under the ECM during the current regulatory control period, as intended by ESCOSA.

In accordance with the ESCOSA SORI, the AER must recognise both capex and opex carryovers accumulated under the ECM in the current regulatory control period. Calculation of efficiency gains or losses in the final year (year five) of the current regulatory control period is to be in accordance with the ECM.[1119]

The ESCOSA SORI requires the AER to carry any net negative efficiency amount calculated in the current regulatory control period ECM as a negative (rather than a zero) amount. The AER has the discretion to either apply a negative carryover amount accumulated under the ECM in the current regulatory control period, or to defer it to offset future positive carryover amounts.[1120]

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:

$$E1 = F1 - A1$$

Where:

E1	=	the efficiency gain/loss in year 1
A1	=	actual opex incurred by the DNSP for year 1 of the regulatory control period
F1	=	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:

$$Et = (Ft - At) - (Ft{-}1 - At{-}1)$$

Where:

[1117] Clause 7.4 of the Electricity Pricing Order allows ESCOSA to publish a statement of regulatory intent which sets out how ESCOSA intends to exercise its powers under chapter 7 of the Electricity Pricing Order.
[1118] ESCOSA, *Statement of Regulatory Intent*, March 2007.
[1119] ESCOSA, *Statement of Regulatory Intent*, March 2007, p. 1.
[1120] ESCOSA, *Statement of Regulatory Intent*, March 2007, clause 4, p. 1.

Et	=	the efficiency gain/loss in year t
At, At–1	=	the actual, or adjusted actual, opex incurred in years t and t–1 respectively
Ft, Ft–1	=	the forecast, or adjusted forecast, opex accepted or substituted by the AER for years t and t–1 respectively.

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:

$$A5 = F5 – (F4 – A4)$$

Where differences arise between this estimate and the actual expenditure amount of the final year, the efficiency gain or loss in the first year of the 2015–20 regulatory control period (E6) will be adjusted as follows:

$$E6 = (F6 – A6) – (F5 – A5) + (F4 – A4)$$

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).

The AER's calculation of efficiency gains or losses realised during the next regulatory control period will be applied to ETSA Utilities' building block revenues for the 2015–20 regulatory control period. The forecast opex amounts for the next regulatory control period must, however, incorporate both negative and positive carryover amounts accrued in any year of the current regulatory control period accumulated under the ECM administered by ESCOSA. Capex efficiencies realised in the current regulatory control period must be applied in the next regulatory control period.

13.3 ETSA Utilities regulatory proposal

For the purposes of calculating EBSS carryover amounts, the forecast opex must be adjusted for the cost consequences of changes in a DNSP's capitalisation policy and differences between forecast and actual demand growth over the next regulatory control period. ETSA Utilities 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 allows DNSPs to propose a range of additional cost categories to be excluded from the operation of the EBSS. ETSA Utilities proposed the following cost categories to be excluded from the EBSS:[1121]

- recognised pass through events
- non–network alternatives
- debt and equity raising costs
- self insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- expenditure that meets all the necessary requirements for an approved pass through event other than satisfying the materiality threshold.

Transitional arrangements

The transitional arrangements contained in the ESCOSA SORI relate to the treatment of negative carryover amounts. ETSA Utilities submitted that:[1122]

- any negative carryover amounts arising from uncontrollable opex cost categories should be deferred and applied against future opex efficiency gains
- even if the negative opex carryover amounts are deferred to be applied against future opex efficiency gains, it is inefficient and inequitable that ETSA Utilities should be obliged to either immediately apply or carryover any significant deferred negative carryover amount for adverse movements in cost categories outside of its control.

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 the network and changes in a DNSP's capitalisation policy.[1123] The EBSS provides that forecast opex is to be adjusted for variances between actual and forecast demand growth over the regulatory 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 an adjustment.[1124]

[1121] ETSA Utilities, *Regulatory proposal*, July 2009, p. 222.
[1122] ETSA Utilities, *Regulatory proposal*, July 2009, p. 223.
[1123] AER, *Final decision*, *Electricity DNSPs EBSS*, June 2008, pp. 6–7.
[1124] NER, clause 6.12.1(9).

ETSA Utilities regulatory proposal

ETSA Utilities did not propose a specific adjustment mechanism to account for the impact of any future changes in capitalisation policies or changes in demand growth.

ETSA Utilities submitted that demand growth adjustments are undesirable because the relationship between demand growth and opex is less direct than the relatively strong relationship between demand growth and capex. It stated that there is no simple mechanistic process that could be applied to adjust actual opex for actual demand growth and the application of an ex–post adjustment to actual opex would unnecessarily increase regulatory uncertainty. ETSA Utilities proposed that there be no demand growth adjustments made to forecast opex for the consequences of changes in demand growth for the next regulatory control period.[1125]

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.[1126] As the risk to DNSPs of being rewarded or penalised by the EBSS for changes in demand growth is symmetrical, the AER considers it reasonable that efficiency carryovers need not be adjusted for changes in outturn demand growth.

Given that ETSA Utilities did not propose a demand growth adjustment mechanism, the AER will not adjust the EBSS carryover for the consequences of changes in demand growth 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.[1127] In addition, the EBSS allows DNSPs to propose additional cost categories to be excluded from the EBSS.[1128] The scheme requires that these cost categories must be proposed by a DNSP in its regulatory proposal for the next regulatory control period.[1129]

ETSA Utilities regulatory proposal

In addition to recognised pass through events and opex on non–network alternatives, ETSA Utilities proposed that the following also be excluded costs for the purpose of calculating the EBSS: [1130]

- debt and equity raising costs
- self insurance costs

[1125] ETSA Utilities, *Regulatory proposal*, July 2009, p. 222.
[1126] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, p. 5.
[1127] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, pp. 6–7.
[1128] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, p. 5.
[1129] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 84.
[1130] ETSA Utilities, *Regulatory proposal*, July 2009, p. 222.

- superannuation costs relating to defined benefit and retirement schemes
- expenditure that meets all the necessary requirements for an approved pass through event other than satisfying the materiality threshold.

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.[1131]

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 the distribution determination, from the operation of the EBSS for ETSA Utilities, 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 (DMIA)
- other specific uncontrollable costs incurred and reported by ETSA Utilities during the next regulatory control period, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS.

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 costs.

The AER considers it appropriate that approved forecasts for 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 therefore beyond the control of the DNSP. Similarly, self insurance and insurance cost

[1131] This approach is consistent with clause 6.5.8(c)(2) of the NEL which requires the EBSS to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure. There is no incentive for DNSPs to reduce operating expenditure for cost categories for which they have no control.

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 ETSA Utilities. 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 be amortised.[1132] In this draft decision the AER maintains this position, that is, ETSA Utilities' equity raising allowance will be added to its regulatory asset base 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 ETSA Utilities' forecast opex allowance.

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.

The AER will consider excluding costs associated with pass through events from the EBSS that are approved pass through events, consistent with the AER's decisions set out in chapter 15 of this draft decision. As discussed in chapter 15, the AER considers that a materiality threshold should apply to pass through events. However, for the purposes of the EBSS, the AER considers that ETSA Utilities' opex costs associated with uncontrollable events should be excluded from the EBSS, irrespective of whether the cost impact of the event satisfies the cost pass through materiality threshold. This is consistent with the AER's position that a DNSP should not be rewarded or penalised under the EBSS, for costs which are beyond its control.

For the purposes of establishing future EBSS carryover amounts at the end of the next regulatory control period, the AER will consider excluding actual costs associated with other uncontrollable cost events that occur during the next regulatory control period, should they be proposed by ETSA Utilities. Any such proposed costs will be assessed by the AER on a case by case basis, with due consideration of the relevant factors under clause 6.6.1(j) of the NER. Costs associated with other uncontrollable events that fail to satisfy the relevant criteria under clause 6.6.1(j) will not be excluded from the EBSS. In assessing costs related to uncontrollable events for

[1132] See, appendix J of this draft decision.

exclusion from the EBSS, the AER will consider both positive and negative cost impacts.

While the AER will assess these costs under the pass through provisions of the NER, any uncontrollable cost events that the AER determines should be excluded for the purposes of the EBSS carryover calculations, will not necessarily be recognised as approved pass through events for any other purposes under the NER or this draft determination.

13.5.3 Transitional arrangements

The NER requires the AER to apply its EBSS to ETSA Utilities in a manner consistent with the ESCOSA SORI.[1133] This transitional arrangement was implemented to facilitate the transition from the ECM, which has applied during the current regulatory control period, to the EBSS.

The EBSS differs from the ECM in two ways:

- it recognises only opex and excludes capex efficiencies
- it excludes uncontrollable costs from carryover amounts.

In accordance with the ESCOSA SORI, the AER will recognise both capex and opex carryovers accumulated under the ECM administered by ESCOSA in the current regulatory control period. Each opex annual carryover amount for the current regulatory control period will be calculated and applied in the opex building block determination for the next regulatory control period. The capex carryover amount for the current regulatory control period will be applied as an adjustment to ETSA Utilities' revenue in the next regulatory control period. Calculation of efficiency gains or losses in the final year (year five) of the current regulatory control period will be in accordance with the ECM.

The AER will incorporate both negative and positive carryover amounts accrued in any year of the current regulatory period into forecast opex amounts for the forthcoming regulatory period. The decision to apply a negative carryover amount in respect of the current regulatory control period ECM, or to defer a negative carryover amount to offset any future positive carryover amount is, under the ESCOSA SORI, subject to the AER's discretion.[1134]

The AER will exercise its discretion to defer a net negative opex carryover with regard to whether the accumulated negative carryover:[1135]

1. was accrued, in whole or in part:

    a. in an opex category that is excluded by the EBSS but not by the ECM, or

[1133] NER, clause 9.25.9(c).
[1134] ESCOSA, *Statement of Regulatory Intent*, March 2007, clause 4, p. 1.
[1135] AER, *Final framework and approach paper*, *ETSA Utilities*, November 2008, p. 88.

b. in an opex category that is an approved uncontrollable cost category under the EBSS in ETSA Utilities distribution determination for the next regulatory control period; and

2. is material in the sense that it is likely to have a significant and undesirable impact on the stability of prices.

The exclusion of capex from the EBSS means that the option of deferring a negative capex carryover amount accumulated under the ECM is not available.

ETSA Utilities regulatory proposal

ETSA Utilities submitted that any negative carryover amounts arising from the uncontrollable cost categories proposed should be deferred and applied against future opex efficiency gains. ETSA Utilities stated that adverse movements in uncontrollable costs have significantly counter–balanced the achievements ETSA Utilities made in efficiency movements where the costs are within its control. ETSA Utilities further submitted that, even if the negative carryover amounts are ‘banked’ and deferred against future efficiency gains, it is inefficient and inequitable to incur penalties for adverse movements in cost categories outside of its control.[1136]

ETSA Utilities submitted that it will already have incurred these negative carryover amounts as costs during the current regulatory control period and its profits and shareholder returns have already been reduced by an amount equivalent to the adverse cost movement, and that to apply these negative carryover amounts again in the EBSS would further penalise ETSA Utilities.[1137]

ETSA Utilities stated that the basis for its position on uncontrollable opex costs stems from a number of regulatory documents (specifically the national electricity code (NEC) and the electricity pricing order (EPO)) and appeal decisions in Victoria in relation to uncontrollable costs and efficiency benefit sharing schemes. ETSA Utilities argued that in applying the ECM under clause 9.29.5(c) of the NER, the AER must have regard to these appeal decisions in calculating the carryover amount or amounts.[1138]

ETSA Utilities argued that the relevant regulatory documents under which the ECM was developed, namely the NEC and the EPO, contained positive language and conceived of ‘incentives’, not ‘disincentives’, and ‘opportunities to increase efficiency’, not ‘exposure to risks from decreased efficiencies’. On this basis, ETSA Utilities concluded that the aspects of the ESCOSA SORI which sought to include uncontrollable cost items within the ECM and which sought to apply a negative carryover amount, either immediately or on a deferred basis, were invalid.[1139]

[1136] ETSA Utilities, *Regulatory proposal*, July 2009, p. 223.
[1137] ETSA Utilities, *Regulatory proposal*, July 2009, p. 223.
[1138] ETSA Utilities, *Regulatory proposal*, July 2009, p. 223.
[1139] ETSA Utilities, *Regulatory proposal*, July 2009, p. 223.

ETSA Utilities proposed that the ESCOSA SORI be read to exclude uncontrollable cost items when calculating the carryover and any negative carryover amount which might result should be disregarded.[1140]

AER considerations

While the ESCOSA SORI provides discretion to bank negative carryovers accumulated under the ECM to offset future positive amounts, the EBSS does not contemplate the banking of negative carryovers. In the development of the EBSS, the AER considered that the potential to offset negative amounts against future positive amounts would dilute the incentives for DNSPs to continually reduce opex.[1141] An accrued net negative carryover may incentivise DNSPs to artificially shift costs into the benchmark year to increase future opex forecasts, as the negative carryover amount calculated in the benchmark year will not be applied until a sufficiently large positive carryover amount is calculated in the following regulatory control period. In addition, the AER considered that a banking mechanism becomes problematic when negative carryovers are accrued consistently in each year of the regulatory control period as the opportunity to offset the negative carryovers against future positive amounts is diminished.[1142] The AER therefore does not accept ETSA Utilities' proposal that any negative carryover amounts arising from uncontrollable cost categories should be deferred and applied against future opex efficiency gains.

The AER, however, does have discretion to defer a negative opex carryover which was accrued in an opex category that is excluded by the EBSS but not by the ECM. The AER considers that it is appropriate that a DNSP not be penalised for uncontrollable opex that accrued under a previous regulatory efficiency carryover mechanism, but would have been excluded under the EBSS if it had applied at the time the negative opex carryover was accrued.[1143] The AER therefore considers that negative opex carryover accrued in respect of the current regulatory control period ECM can be deferred to offset any positive carryover accrued in the next regulatory control period. This deferral is subject to the negative carryover being accrued in an approved uncontrollable opex cost category under the EBSS.

When making a decision on whether or not to approve an uncontrollable cost category, the AER has regard to whether the cost category is genuinely uncontrollable. ETSA Utilities is required to maintain and provide disaggregated opex figures in support of any proposed uncontrollable opex categories to allow administration of the EBSS. The outturn opex for uncontrollable cost categories will not be assumed to be efficient for the purposes of forecasting costs for future regulatory control periods, so that the efficiency of base year costs for these categories will need to be established in ETSA Utilities’ regulatory proposal for the period 2015–20.

[1140] ETSA Utilities, *Regulatory proposal*, July 2009, p. 227.
[1141] For a further explanation, see the AER’s explanatory statement accompanying the proposed EBSS, AER, *Proposed Electricity distribution network service providers efficiency benefit sharing scheme*, April 2008.
[1142] AER, *Final framework and approach paper*, *ETSA Utilities*, November 2008, p. 84.
[1143] AER, *Final framework and approach paper*, *ETSA Utilities*, November 2008, pp. 84–85.

The EBSS does not recognise capex efficiencies. There is therefore no potential for a positive capex carryover against which a net negative capex carryover from the current period could be offset. The discretion to defer a negative capex carryover is not available under the EBSS. The option of banking accumulated net negative carryovers is therefore only available for opex.

13.6 AER conclusion

The AER will apply the EBSS in accordance with its final framework and approach for ETSA Utilities, published in November 2008. Given that ETSA Utilities 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 ETSA Utilities 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 EBSS for the next regulatory control period:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the DMIA
- other specific uncontrollable costs incurred and reported by ETSA Utilities during the next regulatory control period, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS.

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 cost pass through events. For clarity, a recognised cost pass through is one that satisfies the relevant materiality threshold and is approved by the AER.

The AER will allow any negative opex carryover accrued in respect of the ECM in the current regulatory control period to be deferred to offset any positive carryover accrued in the next regulatory control period, provided the negative carryover is accrued in an approved uncontrollable opex cost category under the EBSS.

The AER's conclusion on controllable opex for ETSA Utilities' EBSS is outlined in table 13.1. This forecast will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[1144]

[1144] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, pp. 5–7.

Table 13.1: AER conclusion on ETSA Utilities forecast controllable opex for EBSS purposes ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Total forecast opex	193.7	201.2	208.0	217.9	223.4
Adjustment for debt raising costs	1.5	1.6	1.7	1.7	1.8
Adjustment for self insurance costs	0.6	0.6	0.7	0.7	0.7
Adjustment for insurance costs	2.3	2.5	2.7	2.9	3.0
Adjustment for DMIA	0.6	0.6	0.6	0.6	0.6
Adjustment for superannuation costs	10.1	10.5	10.8	11.2	11.6
Adjustment for non–network alternatives	0.7	0.7	0.7	0.7	0.8
Adjustment for opex carryover[a]	0.6	–15.0	–20.0	–0.1	0.0
Total opex for EBSS purposes	177.3	199.7	210.8	200.2	204.9

Note: Totals may not add due to rounding.
(a) ETSA Utilities, *Regulatory proposal*, July 2009, p. 228.

The impact of the capex carryover from the current regulatory control period for the next regulatory control period is outlined in table 13.2.

Table 13.2: ETSA Utilities' revenue adjustment for capex carryover from the current regulatory control period ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Adjustment for capex carryover	8.4	7.6	4.3	0.1	0.0

13.7 AER draft decision

In accordance with clause 6.3.2(a)(3) of the NER, the application of the EBSS to apply to ETSA Utilities is as specified in section 13.6 of this draft decision.

In accordance with clause 6.12.1(9) of the NER, the EBSS to apply to ETSA Utilities is as set out in the AER's *Final Framework and approach paper ETSA Utilities 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
- other specific uncontrollable costs incurred and reported by ETSA Utilities during the next regulatory control period, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS.

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 cost pass throughs events. Any negative opex carryover accrued under the current regulatory control period efficiency carryover mechanism can be deferred to offset any positive carryover accrued in the next regulatory control period, provided the negative carryover is accrued in an approved uncontrollable opex category under the EBSS.

14 Demand management incentive scheme

14.1 Introduction

This chapter sets out the AER's demand management incentive scheme (DMIS) to apply to ETSA Utilities 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 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.[1145]

On 17 October 2008, the AER published its DMIS to apply to ETSA Utilities for the next regulatory control period.[1146] In its framework and approach, the AER set out its likely approach to applying its DMIS to ETSA Utilities.[1147] The approach involved applying the two parts of the DMIS, Part A (the demand management innovation allowance (DMIA) component) and Part B (the foregone revenue component). The DMIA was capped at $3 million over the next regulatory control period, to be allocated in five equal annual instalments of $600 000.[1148]

This chapter reviews the issues raised by ETSA Utilities in its regulatory proposal and interested parties' submissions. It sets out the AER's considerations and conclusions on how the DMIS will apply to ETSA Utilities 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 ETSA Utilities for the next regulatory control period.[1149] A decision on how the DMIS will apply to a DNSP is a constituent decision of a distribution determination, under clause 6.12.1(9) of the NER.

Under clause 6.4.3(a)(5) of the NER, a DNSP's annual revenue requirement for each regulatory year of the regulatory control period must be determined using a building block approach, including the revenue increments or decrements (if any), arising from the application of the DMIS.

[1145] AER, *Final framework and approach paper, ETSA Utilities,* November 2008, p. 89.
[1146] AER, *Demand management incentive scheme - Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.
[1147] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, pp. 89–99.
[1148] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 98.
[1149] 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 ETSA Utilities regulatory proposal

14.3.1 Application of the DMIS

ETSA Utilities stated its general support for the AER's approach to removing barriers to the implementation of demand management through the DMIS. However it raised the following concerns:

- **Part A: DMIA—**While ETSA Utilities has not proposed any alteration to the DMIA's capped amount of $3 million, it commented on the AER's ex–post assessment process for funds provided under the DMIA. It stated that adequate recognition must be given to the risk that an investigation may fail to produce its intended outcome. ETSA Utilities stated that for the majority of non–network solutions significant unknowns exist in addition to technical and economic barriers to their introduction. It also stated that the business risks associated with relatively new technology can be significant and in particular, demand management projects may fail to deliver, or fail to deliver on time, the assumed reduction in demand at a time of peak loading.[1150]

- **Part B: Foregone revenues—**ETSA Utilities noted its support for the AER's approach under Part B of the DMIS, but stated that restricting recovery to projects approved under the DMIA alone is inappropriate.[1151]

  ETSA Utilities stated that the foregone revenue component should be expanded to apply to any additional demand management project undertaken by ETSA Utilities in the next regulatory control period that does not form part of its regulatory proposal, irrespective of approval under the DMIA. ETSA Utilities stated that without expanding the operation of Part B, a disincentive would exist with regard to the pursuit of demand management options during the next regulatory control period. ETSA Utilities also stated that this is inappropriate given that it is yet to finalise its conclusions on all aspects of its demand management trial programs and has not fully incorporated them into its expenditure, sales or demand forecasts.[1152]

14.4 Submissions

The AER received submissions from Business SA and the South Australian Council of Social Service (SACOSS) regarding the DMIS. Submissions were also received from the Energy Users Association of Australia (EUAA) and UnitingCare Wesley (UCW) with regard to demand management incentives more broadly, and therefore some of the comments raised are considered in other chapters of this draft decision.

[1150] ETSA Utilities, *Regulatory proposal*, July 2009, p. 201.
[1151] ETSA Utilities, *Regulatory proposal*, July 2009, p. 201
[1152] ETSA Utilities, *Regulatory proposal*, July 2009, p. 201.

Business SA

Business SA's submission noted that ETSA Utilities proposes to undertake less trials of demand management projects in the next regulatory control period than it undertook during the current regulatory control period. Business SA submitted that this is due to a number of reasons, including:[1153]

- the lack of direct benefits to ETSA Utilities, even though there are significant societal benefits
- the relatively limited scope and incomplete measurement of the trials
- weak signals from both regulators and the South Australian government regarding the importance of demand side management and the roll out of technologies (such as smart meters and direct load control), that would assist in reducing peak demand.

Business SA noted that the AER does not have the authority to enforce greater demand side management activities upon ETSA Utilities. However, Business SA urged the AER to analyse the scope for reducing capex on the distribution network through increased demand management projects.[1154]

Business SA submitted two options for encouraging demand management initiatives:[1155]

- increasing the DMIA allowance of $3 million
- consideration of partnerships between ETSA Utilities and companies interested in demand management, where both parties share the costs of installing appropriate technologies as well as the benefits of lower demand. Business SA added that any South Australian Government funding or rebates to assist such partnerships would be welcome.

SACOSS

The SACOSS submitted that the regulatory approach appears to absolve ETSA Utilities from any material responsibilities to manage South Australia's growing peak demand and worsening network utilisation and therefore fails the National Electricity Objective. It stated that the long term interests of consumers will not be met under ETSA Utilities' regulatory proposal. It stated that the issue of peak demand in South Australia not only has a detrimental effect on the price and reliability of supply of electricity but also the reliability and hence safety of the national electricity system.[1156]

[1153] Business SA, *Submission to the AER*, August 2009, p. 7.
[1154] Business SA, *Submission to the AER*, August 2009, p. 7.
[1155] Business SA, *Submission to the AER*, August 2009, p. 7.
[1156] SACOSS, *Submission to the AER*, August 2009, pp. 3–4.

SACOSS argued that ETSA Utilities could go beyond trials and deliver significant broad based peak demand reduction solutions in the next regulatory control period.[1157]

SACOSS also stated that the DMIA of $3 million for the next regulatory control period seems disproportionate when compared with ETSA Utilities' proposed total revenue and RAB increases.[1158]

EUAA

The EUAA submitted that it was concerned that the AER's approach to demand management does not provide DNSPs with sufficient incentives to pursue demand management and does not sufficiently prioritise demand management issues. Further, the EUAA submitted that users are very interested in capturing the benefits of demand management and the AER should ensure active engagement of users in order to ensure that demand management opportunities are maximised.[1159]

UnitingCare Wesley

UCW submitted concern with the apparent lack of demand management projects in ETSA Utilities' regulatory proposal, particularly given its various trials in the current regulatory control period. It proposed that the AER set demand management targets and that these targets be discussed through consumer consultative processes.[1160]

14.5 Issues and AER considerations

14.5.1 Part A – DMIA

Issues raised by ETSA Utilities

ETSA Utilities has not proposed any alteration to the capped DMIA amount of $3 million over the next regulatory control period, as set out in the AER's framework and approach. However, it submitted that the AER must, in its assessment of projects to be approved under the DMIA, adequately recognise the risk that projects might fail.

Consistent with the provisions set out in the DMIS, the DMIA will be provided to ETSA Utilities as an ex–ante allowance, with no pre–approval of particular demand management programs.

However, DMIA expenditure by ETSA Utilities on particular demand management projects will be subject to an ex–post assessment. At the end of each regulatory year in the next regulatory control period, the AER will review expenditure incurred by ETSA Utilities in the preceding regulatory year to assess compliance with the DMIA criteria, as set out in the DMIS.[1161] The AER notes that the assessment criteria do not consider the probability of the project's successful reduction of demand or deferral of expenditure.[1162] The DMIA applied to ETSA Utilities focuses on promoting

[1157] SACOSS, *Submission to the AER*, August 2009, p. 4.
[1158] SACOSS, *Submission to the AER*, August 2009, p. 4.
[1159] EUAA, *Submission to the AER, 28 August 2009*, p. 11.
[1160] UCW, *Submission to the AER*, August 2009, p. 14.
[1161] AER, *DMIS - Energex, Ergon Energy and ETSA Utilities*, October 2008, p. 6.
[1162] AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, pp. 5–8.

innovation, capacity and capability in the area of demand management and inherently recognises that developing innovative solutions for demand management is accompanied by a degree of risk to the DNSP.

As part of its annual reporting requirements on the DMIS, ETSA Utilities will be required to submit information about the possible success of a project. For example, such information includes details on the aims and expectations of each demand management project, any identifiable benefits that have arisen and the business case for the project.[1163] However, such information will not be used to assess whether a project is likely to succeed or fail. The annual reporting information requirements outlined in the DMIS serve a variety of purposes, including providing adequate information to stakeholders, assisting in the development and implementation of the AER's approach to demand management incentives in future periods, as well as forming a basis upon which the AER can assess compliance with the DMIA criteria.

ETSA Utilities has sufficient flexibility under the DMIA, in terms of its desired expenditure profile over the period and the projects it can implement. Under the DMIA, ETSA Utilities' projects are not assessed on their probability of reducing demand or forecast expenditures, and can be designed to access broad based efficiencies, as well as peak demand management programs. Accordingly, there are no apparent technological or demand risks from the operation of the DMIA itself that need to be addressed by the scheme.

The AER considers that ETSA Utilities' concerns regarding the ex–post assessment of projects under the DMIA are addressed by the DMIS as it currently stands.

Finally, the AER confirms that ETSA Utilities has included an annual adjustment of $600 000 for each year of the next regulatory control period in their proposal. The amounts have been included in ETSA Utilities' opex forecasts. Consistent with a capped allowance, only CPI escalation will be permitted on the allowance to maintain it in real terms.

Issues raised in submissions

The AER notes that both Business SA and SACOSS have submitted that the DMIA's capped amount of $3 million should be increased. The AER notes that the issue has already been the subject of consideration in the framework and approach process for ETSA Utilities. As noted in the framework and approach, the DMIA is not intended to be the only or even primary source of cost recovery for demand management expenditure. The DMIA is designed to complement the more rigorous assessment (as part of this distribution determination) of a DNSP's demand management costs proposed under its forecast capex and opex.[1164]

The AER notes that within its forecast capex and opex, ETSA Utilities included a smaller number of demand management projects than it undertook during the current regulatory control period.[1165] However, drawing conclusions about the likely impact on demand management based upon the number of a demand management trial

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[1163] AER, *Final framework and approach - ETSA Utilities*, November 2008, pp. 6–8.
[1164] AER, *Final framework and approach - ETSA Utilities*, November 2008, pp. 92–93.
[1165] ETSA Utilities, *Regulatory proposal*, July 2009, p. 200.

projects can be problematic. That is, the ultimate implementation of a demand management project and subsequent reduction in demand or deferral of expenditure may not be correlated with the number of trials. Furthermore, the projects listed by ETSA Utilities in its regulatory proposal do not necessarily comprise the total projects it will pursue and implement in the next regulatory control period.

ETSA Utilities only needs to propose demand management projects as part of this distribution determination if it intends to submit these projects for assessment as part of its forecast opex and capex.[1166] The DMIA provides ETSA Utilities with the opportunity to allocate its allowance of $3 million as required, over the next regulatory control period, and on projects which it selects during that period.[1167] These will be assessed ex–post against the DMIA criteria in the DMIS, and will be eligible for a foregone revenue component under Part B of the DMIS.[1168] Therefore, the DMIS provides ETSA Utilities with the possibility of pursuing and implementing additional demand management projects to those listed in its regulatory proposal.

The AER does not agree with SACOSS' submission that the regulatory approach absolves ETSA Utilities from any responsibilities in the area of demand management. The AER considers, consistent with Business SA's observation, that it is not in a position to enforce the uptake of demand management projects by ETSA Utilities. It is the DNSP's role to develop and select an efficient demand management project and the AER's role is to assess the project. It is also a DNSP's role to ascertain whether its demand management projects can go beyond trialling to implementation. Equally, it is outside of the AER's responsibility to consider any potential partnerships between ETSA Utilities and companies interested in demand management, as well as possible South Australian government funding for such partnerships, as submitted by the EUAA and Business SA.

Further, while the AER cannot enforce the uptake of demand management, it does provide avenues for such uptake. The primary avenue is through the capex and opex assessment process. The AER notes that within this process a DNSP must consider demand management options. The opex and capex factors in sections 6.5.6 and 6.5.7 of the NER provide that the AER must, in its assessment of a DNSP's forecasts, have regard to the extent to which a DNSP has considered and made provision for efficient non–network alternatives. The AER also provides incentives to DNSPs to pursue and implement demand management projects through its DMIS. The DMIS provides ETSA Utilities with the opportunity to claim expenditure on demand management under the DMIA (up to a capped amount) and to recover any revenues foregone from the successful implementation of a demand management project.[1169]

14.5.2 Part B – Foregone revenue

ETSA Utilities has proposed a departure from the design and intention of the DMIS. ETSA Utilities proposed expanding the DMIS to include recovery of foregone

[1166] AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, p. 3.
[1167] AER, *DMIS - Energex, Ergon Energy and ETSA Utilities*, October 2008, p. 5.
[1168] AER, *DMIS - Energex, Ergon Energy and ETSA Utilities*, October 2008, pp. 6–9.
[1169] As noted in section 14.5.2, this is subject to a number of constraints.

revenues from demand management projects implemented outside the scope of Part A.[1170]

ETSA Utilities proposes that under the DMIS, demand management projects that may not meet the ex–post assessment criteria under Part A should still be eligible for consideration under Part B. ETSA Utilities stated this change is necessary as it is yet to finalise its conclusions on all aspects of its demand management trials. Therefore it has not fully incorporated demand management projects into its sales, demand and expenditure forecasts.

The AER notes that the primary sources of recovery for demand management expenditures are through the capex and opex allowances approved by the AER as part of its distribution determination, in accordance with clauses 6.5.6 and 6.5.7 of the NER. These allowances compensate ETSA Utilities for any proposed expenditure on demand management projects. Further, while recognising ETSA Utilities’ concern, the AER notes that an estimated impact of the demand management projects proposed by ETSA Utilities as part of its capex has been incorporated into the demand forecasts. The demand forecasts are set for the regulatory control period. The projects are targeted at reducing peak demand, and are not anticipated to impact significantly on sales forecasts.[1171]

Should ETSA Utilities implement any demand management project not forming part of its regulatory proposal, and outside of the DMIS, it will not be compensated specifically for foregone revenues. However, the AER notes certain offsetting factors will provide ETSA Utilities with some compensation for its demand management efforts. For example, levels of capex and opex approved in the AER’s distribution determination will not change even if a project successfully reduces demand from that forecast as part of the determination. Thus, ETSA Utilities’ costs may reduce due to the decline in demand, but the approved capex and opex, which are commensurate with a higher level of demand, are unchanged.

Alternatively, the DMIS provides ETSA Utilities with other compensation options should it seek to undertake new trials during the next regulatory control period. Such trials can be submitted for DMIA expenditure funding and be eligible for the Part B (foregone revenue component) upon their successful implementation. The foregone revenue component of the DMIS is uncapped and provided in addition to the capped $3 million allowance under the DMIA.[1172]

ETSA Utilities’ proposal to apply Part B to all demand management projects is inconsistent with the design of the DMIS, which already provides ETSA Utilities with flexibility in its operation and application. The AER notes that the matter of whether a project forms part of the proposal for the next regulatory control period is inconsequential. Similar to the process for approving expenditure under the DMIS, the AER will assess the recovery of foregone revenues, ex–post, at the time ETSA

1170 ETSA Utilities, *Regulatory proposal*, July 2009, p. 201.

1171 The AER notes that the majority of demand management projects that ETSA Utilities proposed in its capex forecasts are targeted at reducing demand on the network during peak periods rather than overall sales. These projects include: capacitor banks, peak lopping generation and utilisation of customer generation capacity. ETSA Utilities, *Regulatory proposal*, July 2009, p. 113.

1172 AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, p. 10.

Utilities provides its annual reporting information.[1173] ETSA Utilities will be required to submit information (as outlined in section 3.2.4 of the DMIS) on foregone revenues arising from the successful implementation of demand management projects. The AER will assess this information in accordance with the foregone revenue principles outlined in section 3.2.3 of the DMIS.[1174]

The AER also notes the foregone revenue component compensates for revenue losses arising from a varied range of demand management projects. As Part A of the DMIS provides an allowance for expenditure relating to both peak demand management and broad based demand management projects, both types of projects are eligible for foregone revenue compensation.[1175] The AER notes that in this regard the DMIS applying to ETSA Utilities is broader than that applying to NSW DNSPs under the D–Factor scheme. Under the D–factor scheme demand management cost recovery must be linked to a quantifiable reduction in forecast network augmentation expenditure.[1176]

That said, the DMIS places some restrictions on the Part B component. DNSPs will only be allowed to recover foregone revenue resulting from a reduction in the quantity of electricity sold that is directly attributable to the implementation of a demand management project approved under the DMIA.[1177] However, this restriction is consistent with other demand management schemes in Australia, including the D–Factor scheme applied to NSW DNSPs for the 2009–14 regulatory control period and the DMIS applying to ActewAGL for the 2009–14 regulatory control period. None of these schemes envisage foregone revenue compensation for projects undertaken outside of the respective scheme.[1178]

Another restriction is that while DMIA projects can be non–tariff or tariff based projects, to be allowed a foregone revenue component the project must be non–tariff based.[1179] This seeks to mitigate the possibility of double counting with regard to the compensation provided to DNSPs, given that tariff based demand management projects could lead to revenue increases due to higher prices at peak periods.[1180] This restriction is also consistent with that under the D–Factor scheme and the DMIS applied to ActewAGL.[1181]

Permitting the recovery of foregone revenue on all demand management programs would not only be a departure from a current practice in the design of demand management incentives in Australia, but would also constitute a significant departure from a scheme designed to be modest in nature. In its current form, the DMIS is

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1173 AER, *DMIS – Energex, Ergon Energy, ETSA Utilities*, October 2008, pp. 13–14.
1174 AER, *DMIS – Energex, Ergon Energy, ETSA Utilities*, October 2008, p. 11.
1175 AER, *DMIS – Energex, Ergon Energy, ETSA Utilities*, October 2008, p. 5.
1176 AER, *Demand management incentive scheme for the NSW 2009 distribution determinations — D–factor scheme*, February 2008; and, AER, *Final framework and approach – ETSA Utilities*, November 2008, p. 94.
1177 AER, *DMIS – Energex, Ergon Energy, ETSA Utilities*, October 2008, pp. 10–11.
1178 AER, *DMIS – Demand management incentive scheme for the ACT and NSW 2009 distribution determinations — Demand management innovation allowance scheme*, November 2008, p. 8.
1179 AER, *DMIS – Energex, Ergon Energy, ETSA Utilities*, October 2008, p. 9.
1180 AER, *DMIS – Energex, Ergon Energy, ETSA Utilities*, October 2008, pp. 9–10.
1181 AER, *DMIS – Demand management incentive scheme for the ACT and NSW 2009 distribution determinations — DMIA*, November 2008, p. 8.

deliberately limited in scope as it seeks to complement the broader regulatory framework in providing incentives for DNSPs to carry out non–network alternatives. As mentioned, the DMIS recognises that the primary sources of recovery for demand management expenditure are through the forecast opex and capex approved by the AER, in accordance with clauses 6.5.6 and 6.5.7 of the NER. The DMIS complements this broader framework by providing additional incentives for DNSPs to trial innovative approaches and build capacity and capabilities in the area. The DMIS thus allows greater consideration of non–network alternatives in future, without being subject to the requirements of clauses 6.5.6 and 6.5.7 of the NER. Should some of these innovative approaches prove successful they will also be eligible for revenue compensation under the Part B component.

Finally, the DMIS is also modest, given a number of existing uncertainties. The AER notes a number of reviews are occurring which might impact on approaches to demand management in the future. For example, the AEMC is currently undertaking a review of demand side responses in the NEM, specifically to identify whether barriers or disincentives exist within the NER which inhibit the efficient use of demand side participation.[1182]

The AEMC is also undertaking a review of energy market frameworks in light of climate change policies. The review focuses on assessing how the Carbon Pollution Reduction Scheme and an expanded national Renewable Energy Target may affect the existing energy market frameworks and determining what, if any, amendments to those frameworks are required.[1183] These reviews will culminate in recommendations to the Ministerial Council on Energy (MCE).

While the final outcomes of these reviews are uncertain, it is possible that changes to the regulatory framework may occur. Such changes may, in turn, impact upon the AER’s future design of any national DMIS. The AER will monitor these reviews and subsequent decisions by the MCE.

The AER notes that the DMIS is a new framework that provides incentives for ETSA Utilities to pursue and implement demand management options, and differs to that existing in the current regulatory control period. Further, various options are available to ETSA Utilities for compensation for its demand management efforts, without significantly impacting upon consumer prices at this early stage of development in this field. The AER notes the comments submitted by the EUAA, however, it is difficult to make judgements on the effectiveness of the framework at this point in time. Given these reasons, and the continuing policy uncertainties, the AER considers that it is not appropriate to re-design the DMIS at this stage by altering its function and power.

[1182] Further information on the AEMC’s review is accessible at the following location: <http://www.aemc.gov.au/Market-Reviews/Open/Review-of-Demand-Side-Participation-in-the-National-Electricty-Market.html>.

[1183] Further information on the AEMC’s review is accessible at the following location: <http://www.aemc.gov.au/Market-Reviews/Open/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html>.

14.6 AER conclusion

The AER maintains its position, as set out in its framework and approach, to apply the DMIS to ETSA Utilities. The DMIS will comprise of a Part A (the DMIA component) and a Part B (foregone revenue component). Part A will be capped at $3 million in the next regulatory control period. The capped amount will be allocated to ETSA Utilities as an ex–ante allowance, in five equal instalments of $600 000. The ex–post review and operation of the DMIA will be as set out in the DMIS.

Part B will be uncapped but subject to the restrictions set out in the DMIS. Part B will be applied consistent with the methodology 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 ETSA Utilities is the DMIS set out in the AER's document, *Demand management incentive scheme - Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

Part A (the DMIA component) and the Part B (foregone revenue) of the DMIS will apply to ETSA Utilities. The DMIA will be capped at $3 million for the next regulatory control period and allocated to ETSA Utilities in equal annual instalments of $600 000 for each year of the next regulatory control period.

15 Pass through arrangements

15.1 Introduction

This chapter sets out the AER's assessment of ETSA Utilities' 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 a DNSP can be exposed to risks beyond its control, 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 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 if certain events occur. 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 cost 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 cost 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.

15.3 ETSA Utilities regulatory proposal

ETSA Utilities proposed that the following seven events be included as nominated pass through events in the AER's distribution determination:[1184]

> **Extraordinary event** means an event the occurrence of which was unpredictable, unforeseen, or if foreseen could not be reasonably guarded against, and substantially beyond the reasonable control of ETSA Utilities, as a result of which ETSA Utilities incurs materially higher or lower costs in providing standard control services than it would have incurred but for that event.
>
> A **connection point event** arises if ETSA Utilities undertakes a connection point project, which causes ETSA Utilities to incur material costs which it will not otherwise recover through an increase in distribution revenue. For the purpose of this definition, a connection point project is a project in relation to a metropolitan transmission network connection point (as defined in s21 (7) of the *Electricity Corporations (Restructuring and Disposal) Act 1999*), which ETSA Utilities was not required to undertake at the time it submitted its regulatory proposal.
>
> 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 ETSA Utilities for that regulatory year is higher or lower than the amount of feed-in tariff payments (if any) that is provided for in ETSA Utilities' annual revenue requirement for that regulatory year.
>
> For the purpose of this definition, a feed-in tariff payment is a payment to a customer in relation to electricity fed into the network by that customer (including pursuant to s36AD of the *Electricity Act 1996*). For the avoidance of doubt, a payment includes a credit against charges payable.
>
> An **industry standards change event** occurs if:
>
> a) as a result of the decision of a court, standards authority, Government or Government authority, or outcome of an inquiry commission by a Government or Government authority, a prudent operator, acting reasonably would undertake particular action; and
>
> b) in undertaking that action, ETSA Utilities incurs material costs which it will not otherwise recover through an increase in distribution revenue.

[1184] ETSA Utilities, *Regulatory proposal*, July 2009, pp. 188–191.

A **retailer failure event** occurs if:

a) a retailer is placed in administration, liquidation or their license is revoked; and

b) as a consequence, ETSA Utilities does not receive revenue to which it was otherwise entitled.

A **native title event** occurs if, as the result of a native title claim, ETSA Utilities incurs material costs constituting:

- any compensation or damages payable by ETSA Utilities, for example as a result of a registered Indigenous Land Use Agreement (ILUA), a consent determination or a decision of a Court; and/or

- legal fees and disbursements associated with negotiation and litigation in relation to native title claims.

An **interim period event** is an event that:

a) occurs before the commencement of the relevant regulatory control period;

b) would be a pass through event if it occurred in the regulatory control period; and

c) has a cost impact in the relevant regulatory control period which has not been included in ETSA Utilities' operating and capital expenditure forecasts.

In addition, ETSA Utilities stated that the following events would constitute a 'regulatory change event' or 'service standard event' as defined in chapter 10 of the NER:[1185]

- the introduction of a requirement to roll out smart meters and/or peak demand management equipment.

- the introduction of an emissions trading scheme by the Federal or South Australian Government.

- the requirement to place 66kV powerlines underground either as a result of the Technical Regulator not granting an exemption under the *Electricity (General) Regulations 1997* from the requirements of the *Electricity Act 1996* for overhead clearances or the Development Assessment Commission refusing consent for overhead power lines.

ETSA Utilities proposed that if the AER considers that any of these events would not be covered as a regulatory change event or service standards event, they should be nominated as a pass through event.[1186]

[1185] ETSA Utilities, *Regulatory proposal*, July 2009, p. 186.
[1186] ETSA Utilities, *Regulatory proposal*, July 2009, p. 186.

Materiality threshold

ETSA Utilities submitted that a 'bright line' materiality threshold should not be adopted and that a preferable threshold allows for subjective consideration of whether the occurrence of the event has a material, positive or negative, impact on the costs incurred by the DNSP.[1187]

15.4 Submissions

The South Australian Water Corporation (SA Water) stated it disagrees with the proposed retailer failure event pass through, noting that ETSA Utilities has other options to manage this risk, and the pass through does not incentivise ETSA Utilities to obtain appropriate protection. SA Water also stated that the recovery of debt should be pursued against the customer class that were contracted with the failed retailer, rather than all ETSA Utilities customers.[1188]

SA Water also noted its support for mechanisms to assist the AER, including the materiality threshold, on the basis that it will provide ETSA Utilities and customers with a fair and objective decision.[1189]

The Energy Consumers Coalition of South Australia (ECCSA) stated that allowing an increase in the cost of capital at the same time as reducing the risk faced by ETSA Utilities through expansion of the pass through provisions effectively compensates ETSA Utilities twice for the same risk. ECCSA also noted that the increased capex and opex allowances should be fully utilised before the costs associated with a pass through event are recovered from customers.[1190]

The Energy Users Association of Australia (EUAA) noted ETSA Utilities proposed a number of pass through events and a subjective materiality threshold. The EUAA argued that as ETSA Utilities earns market based returns that compensate them for accepting risks, pass through of costs may not be warranted.

The South Australian Minister for Energy, the Honourable Patrick Conlon MP (SA Energy Minister) noted his support for the proposed undergrounding of 66kV power lines pass through event, and stated it was consistent with current regulatory practice for mandated undergrounding projects.

15.5 Issues and AER considerations

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.[1191] Neither the NEL nor the NER provide any direct guidance to the AER on the matters it should

[1187] ETSA Utilities, *Regulatory proposal*, July 2009, p. 192.
[1188] SA Water, *Submission on ETSA Utilities regulatory proposal*, 28 August 2009, p. 2.
[1189] SA Water, *Submission on ETSA Utilities regulatory proposal*, 28 August 2009, p. 2.
[1190] ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 59–62.
[1191] NER, chapter 10, definition of pass through event.

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.

The revenue and pricing principles in section 7A(2) of the NEL provide:

> (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
>
> (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.[1192]

The NER requires a distribution determination to specify allowances for a DNSP's total capex and opex programs for the next regulatory control period.[1193] 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

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[1192] 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 of distribution services.

[1193] NER, clauses 6.12.1(3) and 6.12.1(4).

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.[1194] Therefore, costs should generally only be passed through once the first two options have been fully exhausted. The AER notes the submission by ECCSA that capex and opex allowances should be fully utilised before a pass through of costs is permitted.[1195] 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 comments from ECCSA, SA Water and the EUAA, the AER considers that its approach to cost pass through events 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.

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:[1196]

- 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

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[1194] NER, chapter 10, definition of positive change event.
[1195] ECCSA, *ETSA Utilities application, a response*, August 2009, pp. 59–62.
[1196] AER, *Final decision, ACT DNSP*, 28 April 2009, p. 127; and AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 277.

- 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 NSW DNSPs, the AER considered an event to be foreseeable if it was expected to occur.[1197] 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.

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

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1197 AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 278.

determination.[1198] 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.[1199] 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. 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

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[1198] NER, chapter 10, definition of pass through event.
[1199] Department of Climate Change, *Carbon Pollution Reduction Scheme, Timetable,* July 2009, at http://www.climatechange.gov.au/emissionstrading/timetable.html.

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
  - ‘native title event’ in this draft decision

In the distribution determinations for the 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.[1200] 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 the definition of a general pass through event includes 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

[1200] AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 296.

period and once the particular circumstances of an event are known, whether a general nominated event has occurred.[1201]

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. The AER notes the support of SA Water for an objective materiality threshold to apply to cost pass throughs.

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 revenue allowance specified in the final decision in the years of the regulatory control period that the costs are incurred.[1202]

ETSA Utilities submitted that an approach to materiality, involving a subjective consideration of whether the occurrence of the event has had a material impact on a DNSP's costs, should be preferred because it avoided inequity and was more flexible.[1203]

The AER considers that a specific materiality threshold will provide certainty about the magnitude of the cost impacts that are necessary before costs should be eligible for pass through. This will decrease the administrative costs of DNSPs and the AER in applying for and assessing applications for cost pass through, and strengthen the incentive to manage expenditure efficiently. A threshold based on a percentage amount also avoids inequity, as the impact on the financial position will be proportionately the same across all DNSPs.

The AER will adopt the same threshold for general nominated events as that adopted in the distribution determinations for the ACT and NSW DNSPs. This threshold is 1 per cent of the 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

[1201] NER, clause 6.6.1(d).
[1202] AER, *Final Decision NSW DNSPs*, 28 April 2009, p. 280; and AER, *Final Decision, ACT DNSP*, 28 April 2009, p. 130.
[1203] ETSA Utilities, *Regulatory proposal*, July 2009, p. 192.

materiality threshold 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 capital 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 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 NER defined events

ETSA Utilities submitted that the following events would constitute regulatory change events or service standard events:

- a requirement to roll out smart meters and/or peak demand management equipment
- introduction of an emissions trading scheme
- undergrounding of powerlines.

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 or service standard events, as part of its distribution determination. This is because it is not possible to conclude that the NER definitions of a regulatory change event or service standard event are satisfied before the details and impact of the event are known.

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 therefore the definition of a regulatory change event will be satisfied.[1204] Therefore, if the obligation has a material impact on ETSA Utilities' 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 ETSA Utilities is known.

The manner in which any emissions trading scheme would impose obligations and its potential impact on a DNSP is not known, and it is therefore not possible to state whether this event would be likely to constitute a regulatory change event.

As noted in section 15.5.4, the AER considers that the smart meter and emissions trading scheme events should be nominated pass through events.

A requirement to underground powerlines is not an unusual requirement for a DNSP in certain operating environments. ETSA Utilities' regulatory proposal already includes an allowance for undergrounding powerlines based on existing operational requirements and historical trends. However, as noted by the South Australian Energy Minister it is conceivable that additional undergrounding requirements may be made that would impose materially higher costs than those contemplated at the time ETSA Utilities' regulatory proposal was submitted. Such additional undergrounding requirements could substantially vary the manner in which ETSA Utilities is required to provide direct control services or alter the nature or scope of direct control services. It is possible, in such circumstances, that this may constitute a service standard event or a regulatory change event. Given that the circumstances of such an event appear to be captured by the existing NER defined events, the AER considers a specific nominated pass through is not necessary for this event.

15.5.4 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.[1205] 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

[1204] MCE, *Standing Committee of Officials Policy Response, National Electricity Amendment Bill - Smart Meters*, June 2009, p. 8.

[1205] MCE, Standing Committee of Officials, *National Electricity (South Australia) (Smart Meters) Amendment Bill 2009, Exposure Draft 3/7/2009*, Available: www.mce.gov.au.

uncontrollable, because if the event occurs, ETSA Utilities will be legally obliged to undertake trials and/or roll outs.

As noted in section 15.5.2, it is not possible to determine at the time of this draft decision whether this event would be likely to be a regulatory change event, as the impact of the event on ETSA Utilities is not known. Therefore, it is not clear whether or not such an event would be already captured by the defined event definitions.

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.

ETSA Utilities proposed a definition for a smart meter event that included a requirement to roll out smart meters and/or peak demand management equipment. While it is highly likely that ETSA Utilities will be required to conduct trials and/or to roll out smart meters during the next regulatory control period, there is no indication that this requirement will be extended to peak demand management equipment. Therefore, the smart meter event will apply to obligations relating to smart meters only.

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.

Carbon Pollution Reduction Scheme (CPRS) event

The Commonwealth Department of Climate Change has published a timetable indicating that a CPRS will commence by 2010.[1206] 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, ETSA Utilities will be legally obliged to participate 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 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 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.

[1206] Department of Climate Change, *Carbon Pollution Reduction Scheme*, Timetable, 2 July 2009, at http://www.climatechange.gov.au/emissionstrading/timetable.html.

Feed-in tariff event

As of July 2008, the South Australian 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. ETSA Utilities proposed a pass through event to capture forecast errors associated with the amount of payments made under the scheme.

The AER acknowledges that ETSA Utilities has little historical data to reliably forecast the payments that they will be required to make under the scheme during the next regulatory control period. Therefore it is probable that discrepancies will arise between the actual payments ETSA Utilities is required to make under the scheme and its forecast of the level of those payments. Hence, while the event is highly likely to occur, the cost impact is difficult to forecast. The AER considers it appropriate that ETSA Utilities 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, ETSA Utilities 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 ETSA Utilities to pursue productivity improvements, because they cannot influence the parameters which impact the direct payments under the feed-in tariff scheme, and it will only recover incremental amounts.

Therefore, the AER has nominated a feed-in tariff event as a nominated pass through event.

In its regulatory proposal, ETSA Utilities submitted that no materiality threshold should apply to a feed-in tariff event.[1207] 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 ETSA Utilities' submission that no materiality threshold should apply to this event. The materiality threshold that will apply to the feed-in tariff event will be equal to the administrative costs of assessing the pass through application.

Native title event

The AER considers that given ETSA Utilities' current involvement in ten native title matters, it is highly likely that it will incur costs as the result of an obligation to pay compensation or damages or through the payment of legal fees and disbursements in

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[1207] ETSA Utilities, *Regulatory proposal*, July 2009, p. 189.

relation to these matters.[1208] In addition, the timing and cost impact of this event cannot be forecast at the time of ETSA Utilities' regulatory proposal. The event is uncontrollable because it is unknown when claims for native title may be made and the process and the costs of that process are generally controlled by a court.

The other factors listed in section 15.5.1 also support the nomination of a native title event. Therefore, the AER has nominated a native title event as a nominated pass through event. The native title matters to which this specific nominated pass through event pertains are the ten native title matters in which ETSA Utilities is currently involved.[1209]

The AER considers that ETSA Utilities may become involved in other native title matters during the next regulatory control period. Any such native title matters are excluded from the definition of a specific nominated native title pass through event for this distribution determination. Such future events, while possible, cannot be clearly identified at this time. In addition such events do not seem highly likely to occur. As such, native title events do not in general meet the criteria for a specific nominated pass through event. However, the costs of any other native title matters (not specified in ETSA Utilities' regulatory proposal) may meet the criteria for a general nominated pass through event. The AER would undertake such an assessment at the time a pass through application is made.

15.5.5 Proposed pass through events that the AER does not accept

Extraordinary event

This event relates to events which are unpredictable, unforeseen or cannot be reasonably guarded against and have a material impact on ETSA Utilities' costs. The event definition proposed by ETSA Utilities was based on that used by ESCOSA in the current regulatory control period and is similar in principle to the AER's general nominated event.

Extraordinary events cannot be said to be highly likely to occur in the next regulatory control period, and ETSA Utilities noted that it would not expect this type of event to occur.[1210] Given that the event is not highly likely to occur and covers similar circumstances to the AER's general nominated event, the AER does not consider that this event should be a specific nominated event.

Should an event of this type occur, and have a material impact on ETSA Utilities' costs, the event may constitute a general nominated pass through event. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

Connection point project event

The AER considers that it is not highly likely that ETSA Utilities will be required to undertake projects of this type which it was not required to undertake at the time it

[1208] ETSA Utilities, *Regulatory proposal*, July 2009, p. 191.
[1209] ETSA Utilities, *Regulatory proposal*, July 2009, attachment PT04 listing of native title claims, confidential.
[1210] ETSA Utilities, *Regulatory proposal*, July 2009, p. 188.

submitted its regulatory proposal. In addition, the AER considers that nominating a connection point event may weaken ETSA Utilities' incentives to undertake prudent and efficient planning activities, as required to promote economic efficiency regarding investment in its distribution system.[1211] If ETSA Utilities was permitted to pass through the costs of any project not factored into its forecasts, the incentive to base forecasts on efficient investment and operational decisions would be diminished. For these reasons, the AER considers that the connection point project event should not be nominated as a specific pass through event.

Should an event of this type occur, and have a material impact on ETSA Utilities' costs, the event may constitute a general nominated pass through event. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

Industry standards change event

This event relates to changes to the actions of a prudent operator resulting from the decisions of courts, standards authorities, government authorities or inquiries. The AER does not accept that this event should be nominated, because it is not highly likely to occur. ETSA Utilities has not provided any information to suggest that such decisions are expected, nor as to the form or content of any such decisions. Should an event of this type occur and have a material effect on ETSA Utilities' costs, it 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.

Retailer failure event

This event relates to revenue lost by ETSA Utilities as a result of a retailer being placed into administration, liquidation or their license being revoked. While it is possible that retailer failure will occur in the next regulatory period, ETSA Utilities has not provided any information to suggest that such an event is highly likely to occur.

The AER also notes SA Water's submission regarding management of this risk and the likely impact on incentives of allowing this pass through event. In particular the AER does not consider it appropriate to define cost pass through events that negate the incentive on the service provider to efficiently manage risk.

Therefore, the AER considers that this event should not be nominated as a specific pass through event. Should an event of this type occur and have a material effect on ETSA Utilities' costs, it 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.

[1211] NEL, section 7A(3)(a).

Interim period event

ETSA Utilities proposed a pass through event to address situations where an event occurs before the commencement of the next regulatory period, but the cost impact of the event is incurred during the next regulatory period. ETSA Utilities noted:[1212]

> Interim period events are events that, but for their timing, would be pass through events

The AER considers that there is no power in the NER to nominate an event that occurs before the commencement of the next regulatory control period. Under clause 6.12.1(14) of the NER, a constituent decision of an AER determination is 'the additional pass through events that are to apply for the regulatory control period'. The AER considers that an event which takes place before the next regulatory control period lies outside the scope of this decision and therefore the AER is unable to nominate an interim period event.

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 ETSA Utilities' regulatory proposal is sufficient to meet the requirements of clause S6.1.3(2).

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 decision 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 ETSA Utilities:

> A **smart meter event** is an event which results in an obligation being externally imposed on ETSA Utilities 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:

[1212] ETSA Utilities, *Regulatory proposal*, July 2009, p. 191.

- the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)

- 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 ETSA Utilities arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or South Australian government during the course of the next regulatory control period and which:

(a) does not fall within any of the following:

- the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)

- any other category of pass through event

(b) materially increases the cost of providing direct control services.

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 ETSA Utilities for that regulatory year is higher or lower than the amount of feed-in tariff payments (if any) that is provided for in ETSA Utilities' annual revenue requirement for that regulatory year.

For the purpose of this definition, a feed-in tariff payment is a payment to a customer in relation to electricity fed into the network by that customer (including pursuant to s36AD of the *Electricity Act 1996*). For the avoidance of doubt, a payment includes a credit against charges payable.

A **native title event** occurs if, as the result of any of the 10 native title matters in which ETSA Utilities is currently involved (identified in ETSA Utilities, *Regulatory proposal*, July 2009, attachment PT04 listing of native title claims, confidential), ETSA Utilities incurs material costs constituting:

- *any compensation or damages payable by ETSA Utilities for example as a result of a registered Indigenous Land Use Agreement (ILUA), a consent determination or a decision of a Court; and/or*

- l*egal fees and disbursements associated with negotiation and litigation in relation to native title claims.*

15.7.2 General nominated pass through event

The AER nominates the following general pass through event for ETSA Utilities:

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
>
> ‘native title 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 forecast revenue 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 ETSA Utilities should not be nominated as specific nominated pass through events. However, if the event occurs, the AER notes that ETSA Utilities 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 an application for a cost pass through event (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 ETSA Utilities recovers only incremental costs, and the efficiency of ETSA Utilities’ decisions and actions in relation to the event, including whether ETSA Utilities 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 ETSA Utilities for the next regulatory control period are the:

- smart meter event
- CPRS event
- feed-in tariff event
- native title 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 ETSA Utilities for the provision of standard control services for each year of the next regulatory control period. This chapter also sets out X factors to be applied as part of the weighted average price cap (WAPC) to apply to the standard control services provided by ETSA Utilities.

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 AER must set the X factor with regard to ETSA Utilities' total revenue requirement for the period. The X factor must be set to equalise (in net present value terms) the revenue to be earned from the provision of standard control services with the total revenue requirement attributable to those services. The X factor must also minimise difference between expected revenue and the annual revenue requirement for the last year of the regulatory control period.

ETSA Utilities' building block proposal must be prepared in accordance with the AER's post–tax revenue model (PTRM) and the requirements of part C and schedule 6.1 of the NER. The building block proposal must also comply with the requirements of any relevant regulatory information instrument, such as a regulatory information notice (RIN) or a regulatory information order (RIO).[1213]

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 ETSA Utilities and accepted by the AER, or otherwise determined by the AER under part C of the NER.

[1213] NER, clause 6.3.1.

16.2.1 Annual building block revenue requirement

Clause 6.4.3(a) of the NER set out the following building blocks that form the annual revenue requirement:

- indexation of the regulatory asset base (RAB)
- return on capital
- depreciation
- forecast opex
- estimated cost of corporate income tax
- revenue increments or decrements arising from the application of any efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS) and demand management incentive scheme (DMIS)
- 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[1214] and associated handbook[1215]. 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 ETSA Utilities regulatory proposal

ETSA Utilities' calculation of annual revenue requirements and X factors summarised in table 16.1.

[1214] AER, *Final decision, Electricity distribution network service providers, Post–tax revenue model*, June 2008.

[1215] AER, *Electricity distribution network service providers: Post–tax revenue model handbook*, June 2008.

Table 16.1: ETSA Utilities' proposed annual revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation		100.5	115.4	130.4	147.7	165.2
Return on capital		272.3	301.9	340.3	377.1	411.7
Operating expenditure		208.3	225.4	242.9	263.5	280.7
Tax allowance		27.0	28.6	28.5	30.8	31.9
Transitional amounts		–16.5	1.7	3.4	2.0	0.0
Annual revenue requirements		591.6	673.0	745.4	821.1	889.4
Expected revenues	541.5	597.6	664.0	736.6	815.6	908.9
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–10.0	–10.0	–10.0	–10.0	–10.0

Source: ETSA Utilities, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

ETSA Utilities proposed an X factor of –10 per cent (that is, a real increase) for each year of the next regulatory control period. This constant percentage resulted in the net present values (NPVs) of the annual revenue requirements and expected revenues[1216] being equal over the next regulatory control period as shown in table 16.2.

Table 16.2: ETSA Utilities' proposed annual revenue requirements and expected revenues ($m, nominal)

	NPV	2010–11	2011–12	2012–13	2013–14	2014-15
Annual revenue requirements	2841.1	591.6	673.0	745.4	821.1	889.4
Expected revenues	2841.1	597.6	664.0	736.6	815.6	908.9
Difference (%)		1.0	–1.3	–1.2	–0.7	2.2

Source: ETSA Utilities, PTRM.

16.4 Submissions

Submissions from the Council on the Ageing Seniors Voice (COTA), Business SA, SA Water, UnitingCare Wesley (UCW), the South Australian Council of Social Service (SACOSS), the Energy Users Association of Australia (EUAA) and the Energy Consumers Coalition of South Australia (ECCSA) all expressed concern about the significant price increases resulting from ETSA Utilities' regulatory

[1216] 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 ETSA Utilities) 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.

proposal. The key effects anticipated by these interested parties due to the price rises were:

- detrimental social impacts on the elderly and low income families[1217]
- negative economic impacts on business activity.[1218]

The EUAA also noted that large tariff increases are often imposed without adequate notice. It considered that the AER should be using these opportunities to provide better and more advance notice of likely tariff changes resulting from its reviews. The EUAA noted that ETSA Utilities' proposal gave some indicative numbers to provide users with some indication as to the impacts on electricity prices. However, the EUAA considered that these numbers are very difficult to interpret and proposed that the AER develop a standard template for providing such data.[1219]

16.5 Issues and AER considerations

The following sections address briefly each of the building blocks proposed by ETSA Utilities. Further details on the AER's consideration of ETSA Utilities' 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 outlined in this chapter.

16.5.1 Proposed price increases and X factors

The X factors proposed by ETSA Utilities represent the real price changes that customers will face for each year of the next regulatory control period. Based on the X factors proposed by ETSA Utilities and assuming that distribution network charges make up 40 per cent of end users' electricity bills, end users' bills would rise (in real terms) by 4 per cent per annum over 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
- 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.

[1217] See for example, COTA, *ETSA distribution price review*, 27 August 2009, p. 2.
[1218] See for example, Business SA, *Submission to the AER*, August 2009, pp. 4–5.
[1219] EUAA, *Submission to the AER*, 28 August 2009, p. 8.

The AER's draft decision on ETSA Utilities' X factors and the resulting effect of end users' electricity bills are presented in section 16.6.

16.5.2 Information on proposed changes to tariffs

The EUAA raised concerns regarding the detail of pricing information contained in ETSA Utilities' regulatory proposal. The AER notes that ETSA Utilities has provided some pricing information as part of its pricing proposal, although this information is necessarily at an aggregate level given the nature of the AER's building block assessment. The X factors presented in this chapter reflect the overall real price changes customers can expect each year of the next regulatory period. 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 these overall prices changes are then converted to specific tariffs is a matter ETSA Utilities must address as part of its pricing proposal 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 ETSA Utilities provide an indicative outline of its pricing structures for 2010–11 well in advance of the deadlines required by legislation, which the AER considers are particularly tight for assessing prices.[1220]

16.5.3 Accuracy of existing prices and forecast sales quantity inputs

The AER has examined the accuracy of the pricing inputs to the PTRM for 2009–10 in terms of whether they reflect the prices approved by ESCOSA. This is important as they are used in the PTRM to model the starting point from which prices will be escalated under the WAPC and therefore affect the calculation of X factors. The AER found that the pricing information provided by ETSA Utilities was accurate. However, some customers had been reassigned from tariffs that are now obsolete. ETSA Utilities will need to demonstrate, as part of its pricing proposal, consistency with the reasonable estimates approach as discussed in chapter 4. In addition, as discussed in chapter 2, the AER considers that certain metering services should be treated as alternative control services, which means that the metering tariffs/tariff components associated with these services were removed from ETSA Utilities' PTRM for standard control services.

The AER has also examined the forecast energy and customer number data submitted by ETSA Utilities. As discussed in chapter 6, the AER engaged MMA to review ETSA Utilities' proposed customer numbers, while AEMO was engaged to review ETSA Utilities' energy forecasts. MMA considered ETSA Utilities' forecasts of customer numbers were reasonable. The AER has considered and accepted these forecasts. However, AEMO had concerns ETSA Utilities quantity forecasts. As discussed in chapter 6, the AER agreed with AEMO's assessment and requested updated quantity data (down to the tariff component level) from ETSA Utilities which has been incorporated into this draft decision.

[1220] NER, clause 6.18.2(a).

16.5.4 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, which is marginally lower than the 2.47 per cent used by ETSA Utilities in its PTRM.

16.5.5 Asset base roll forward and indexation

As discussed in chapter 5, the AER has determined the opening value of ETSA Utilities' RAB as at 1 July 2010 to be $2768.3 million. The AER has rolled forward ETSA Utilities' RAB for the next regulatory control period using the PTRM and as shown in table 16.3.

Table 16.3: AER's forecast roll forward of ETSA Utilities' regulatory asset base ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15
Opening RAB	2768.3	2995.9	3271.2	3500.8	3728.5
Net capex [a]	327.9	388.4	356.3	370.2	376.7
Indexation of the opening RAB	67.8	73.4	80.1	85.8	91.3
Straight–line depreciation	168.1	186.5	206.7	228.2	249.3
Closing RAB	2995.9	3271.2	3500.8	3728.5	3947.3

Note: The straight–line depreciation less the indexation of the opening RAB provides the regulatory depreciation building block.

(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. This capex also includes capitalised equity raising costs.

16.5.6 Return on capital

The AER considers that ETSA Utilities' 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 ETSA Utilities' opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.5.

The nominal vanilla WACC of 10.02 per cent is based on a post–tax nominal return on equity of 10.57 per cent and a pre–tax nominal return on debt of 9.66 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 ETSA Utilities.

16.5.7 Depreciation

As discussed in chapter 10, the AER has not approved ETSA Utilities' 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 16.5 shows the resulting figures.

16.5.8 Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for ETSA Utilities of $1090.7 million (nominal) over the next regulatory control period. Table 16.5 shows the annual opex allowance, which equals an average amount of $218.1 million per annum in nominal terms.

16.5.9 Estimated taxes payable

As discussed in chapter 9 of this draft decision, using the PTRM the AER modelled ETSA Utilities' benchmark income tax liability for 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 ETSA Utilities' 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 42.7 per cent for this draft decision. Table 16.4 shows the AER's estimate of ETSA Utilities' net tax allowance.

Table 16.4: AER modelling of ETSA Utilities' net tax allowance ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Tax payable	91.3	94.2	92.6	97.3	100.7
Value of imputation credits	59.3	61.2	60.2	63.2	65.5
Net tax allowance	31.9	33.0	32.4	34.0	35.2

16.5.10 Revenue decrements from previous period control mechanisms

As discussed in chapter 4, the AER has rejected ETSA Utilities' proposal to include a forecast for the transitional amounts (associated with the transitional ($EDPD_{t)}$ factor in the WAPC) in determining the X factors in the PTRM. These transitional amounts forecast by ETSA Utilities were shown in table 16.1. Instead, the AER considers the $EDPD_t$ factor should be applied independently of the X factor and based on actual results for the various component that make up the $EDPD_t$ factor. ETSA Utilities will need to provide the actual amounts (and a demonstration of how they were calculated) as part of its pricing proposal.

16.6 AER conclusion

The AER has calculated ETSA Utilities' annual revenue requirements and X factors based on its decisions regarding the building blocks.

The AER's draft decision results in a total revenue requirement for the next regulatory control period of $3549 million, compared to $3720 million proposed by ETSA Utilities. The main reasons for this difference reflect the net effect of:

- removal of the $243 million from ETSA Utilities' opening RAB (see chapter 5). This amount related to the revaluations ETSA Utilities made to its RAB for easements, the reinstatement of capital contributions that the AER has disallowed, the removal of metering assets used for alternative control services from the RAB and an updated CPI figure for 2008–09.
- removal of the $638 million from ETSA Utilities' forecast capex[1221]
- removal of the $131 million from ETSA Utilities' forecast opex[1222]
- a higher WACC than proposed by ETSA Utilities.

[1221] This figure is in $2009–10 and before the removal of capex associated with meters, which are to be treated as alternative control services.

[1222] This figure is in $2009–10 and before the removal of opex associated with metering services that are to be treated as alternative control services.

Table 16.5: AER conclusion on ETSA Utilities' annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	100.3	113.1	126.6	142.4	157.9
Return on capital[a]	277.5	300.3	327.9	350.9	373.7
Operating expenditure[b]	192.3	204.6	216.8	232.7	244.3
Tax allowance	31.9	33.0	32.4	34.0	35.2
Capex carryover[c]	8.4	7.6	4.3	0.1	0.0
Annual revenue requirements	610.4	658.6	708.0	760.3	811.3
Expected revenues	616.4	653.2	703.9	756.8	818.4
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors [d] (%)	–10.95	–3.90	–3.90	–3.90	–3.90

Source: AER, PTRM.
(a) Includes equity raising costs.
(b) Includes demand management innovation allowance, self insurance and feed-in tariffs.
(c) This adjustment is discussed in chapter 13.
(d) Negative values for X indicate real price increases under the CPI–X formula.

In deciding on ETSA Utilities' X factors, the AER has decided not to apply a constant X factor for the next regulatory control period as proposed by ETSA Utilities. To do so, would lead to a significant divergence between the expected revenues and the annual revenue requirement for the last year of the next regulatory control period. Such a divergence is to be minimised under clauses 6.5.9(2) of the NER. Accordingly, the AER has adopted the approach used by the Qld DNSPs of using a different X factor (Po) for the first year of the next regulatory control period and then holding the X factor constant for the remaining years of the next regulatory control period. Using this approach, the AER changed the X factor from –10.00 per cent to –10.95 per cent for 2010–11, while it changed the X factor from –10.00 per cent to –3.90 per cent for the remaining years of the next regulatory control period.

The sizes of the X factors were significantly affected by the revised energy forecasts (as discussed in chapter 6), which lowered the expected per unit price increases.

The impact of the X factors in terms of real end use prices of the AER's decision, compared with ETSA Utilities regulatory proposal, is outlined in table 16.6.

Table 16.6: Real price impacts – ETSA Utilities regulatory proposal and AER draft decision (%)

	2010–11	2011–12	2012–13	2013–14	2014–15
ETSA Utilities regulatory proposal	4.0	4.0	4.0	4.0	4.0
AER draft decision	4.4	1.6	1.6	1.6	1.6

Note: Calculations assume distribution network charges make up 40 per cent of an end user's bill.

The price impacts above exclude the effect of any annual adjustments for such matters as the transitional $EDPD_t$ factor and any pass through costs. These adjustments will be accounted for as part of the annual price approval process.[1223]

16.7 AER draft decision

In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement proposed by ETSA Utilities.

In accordance with clauses 6.12.1(2)(ii) and 6.3.2(a)(4) of the NER, ETSA Utilities' 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 ETSA Utilities are as specified in table 16.5 of this draft decision.

In accordance with clause 6.3.2(a)(1) of the NER, ETSA Utilities' annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.5 of this draft decision.

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of ETSA Utilities' regulatory asset base is as specified in section 16.5.5 of this draft decision.

In accordance with clause 6.3.2(a)(5) of the NER, any other amounts, values or inputs on which ETSA Utilities' building block determination is based are as specified in sections 16.5 and 16.6 of this draft decision.

1223 Based on the forecasts for these factors included in ETSA Utilities' regulatory proposal, these adjustments are likely to reduce the size of the price increase for the first year of the next regulatory control period.

17 Alternative control 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 ETSA Utilities' alternative control services control mechanism and how compliance with that mechanism is to be demonstrated in the next regulatory control period.

The AER's classification of ETSA Utilities' alternative control services is set out in chapter 2 of this draft decision.

17.2 Regulatory requirements

Clause 6.8.1of the NER requires the AER publish a framework and approach paper in anticipation of every distribution determination, which (amongst other things) includes the control mechanisms to apply to direct control services.

Clause 6.2.5(d) of the NER outlines the factors the AER regard 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.

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 set out in the framework and approach paper.

17.3 AER framework and approach

The AER's framework and approach sets out a weighted average price cap (WAPC) control mechanism for ETSA Utilities' alternative control services (variable standard small customer metering services and the exceptional cases of large customer metering) for the next regulatory control period.[1224] The WAPC formula to apply to ETSA Utilities' alternative control services for the next regulatory control period as set out in the framework and approach is expressed by the formula set out below:[1225]

$$(1 + CPI_t) \times (1 - X) \geq \frac{\sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n} \sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}}$$

where ETSA Utilities has *n distribution tariffs*, which each have up to *m distribution tariff components,* and where:

[1224] AER, *Final framework and approach paper, ETSA Utilities*, November 2008.
[1225] AER, *Final framework and approach paper, ETSA Utilities,* November 2008, appendix D, p. 130.

regulatory year 't' is the *regulatory year* in respect of which the calculation is being made;

regulatory year 't–1' is the regulatory year immediately preceding *regulatory year t;*

regulatory year 't–2' is the regulatory year immediately preceding regulatory year *t–1;*

p_t^{ij} is the proposed *distribution tariff* for component *j* of *distribution tariff i* in *regulatory year t* ;

p_{t-1}^{ij} is the *distribution tariff* being charged in *regulatory year t–1* for component *j* of *distribution tariff i;*

q_{t-2}^{ij} is the quantity of component *j* of *distribution tariff i* that was delivered in *regulatory year t–2*;

CPI_t is calculated as follows:

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t*;
>
> divided by
>
> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t–1*;

X is determined using the building block approach

ETSA Utilities is required to include proposed distribution tariff classes (n) and components (m) for both variable standard small customer metering services and the two exceptional case metering services.

17.4 ETSA Utilities regulatory proposal

ETSA Utilities proposed that alternative control metering services be reclassified as standard control services. ETSA Utilities proposed to use the same control mechanism as applying to standard control services. ETSA Utilities stated that separate tariff components would be created within the standard control services WAPC to recover the cost of providing the metering services classified as alternative control services in the AER's framework and approach rather than a separate WAPC for those services.[1226]

17.5 Submissions

The AER did not receive any submissions relating to the alternative control services control mechanism.

[1226] ETSA Utilities, *Regulatory proposal*, July 2009, pp.55–56 and 273–274.

17.6 Issues and AER considerations

As permitted under the NER, ETSA Utilities submitted a change to the classification of alternative control services. For the reasons discussed in chapter 2 of this draft decision the AER has not accepted ETSA Utilities proposed reclassification of variable standard small customer metering services and the two exceptional case metering services.

In response to the AER, ETSA Utilities provided a separate building block PTRM and WAPC for alternative control services. ETSA Utilities noted that a number of simplifying assumptions had been made to provide the information to the AER prior to its draft decision. It noted it may reconsider some of these assumptions in its revised regulatory proposal.[1227]

17.6.1 ETSA Utilities alternative control services proposal

Control mechanism

ETSA Utilities proposed to apply the WAPC with a prospective CPI–X price control. The formula set out by ETSA Utilities included a component for pass throughs. ETSA Utilities noted that given that there is only one alternative control service there is no reason to apply a side constraint.[1228]

Opening asset value

ETSA Utilities stated that in the current regulatory control period low voltage services (LVS) and metering services assets were included in one asset category – LVS and meters. For the purposes of developing an alternative control services asset base ETSA Utilities separated LVS and metering assets as at 30 June 2004.[1229] It removed the value of the metering assets from the standard control RAB as at 1 July 2005 and included that value as the opening asset base for alternative control services. ETSA Utilities stated that the proportion of assets were determined by reference to the actual proportion of metering capex from the five years 2003–04 to 2007–08 based on accounting data. ETSA Utilities also stated that the actual and estimated capex in respect of LVS and metering services up to 30 June 2010 has been separately rolled forward. ETSA Utilities adopted an opening asset value of $82.61 million (as at 1 July 2010) for its alternative control metering services.[1230]

Exit charge

Based on recent trends, ETSA Utilities stated that it had experienced significant and increasing losses of large and small customer meter customers to other meter providers. It therefore proposed that an exit charge be developed to account for the written down value of metering assets that are subject to customers moving to other meter service providers. ETSA Utilities stated that the proposed exit fee is based on a

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[1227] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, confidential.
[1228] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, section 7, confidential.
[1229] ETSA Utilities stated that this year is the initial year used to populate the roll forward model.
[1230] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, SI 618 PTRM, meters (input sheet J7), confidential.

50 percent depreciated asset value at the time of withdrawal from service and the marginal back office cost for facilitating the transfer of the service.

Based on its methodology for estimating the annual metering customer churn, ETSA Utilities proposed to deduct the average written down value of the assets associated with these customer numbers from the asset base in the year of the forecast churn.[1231] However, on the basis that these amounts are taxable, ETSA Utilities accounted for these amounts as capital contributions in the alternative control services PTRM. The amounts thus proposed as capital contributions are shown in table 17.1. The AER understands that ETSA Utilities intends to recover the exit charge as a proposed negotiated distribution service.[1232]

Table 17.1: ETSA Utilities forecast asset value reductions for customer churn ($million, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Capital contributions	0.4	0.3	0.3	0.2	0.2

Source: ETSA Utilities, response to information requests AER EU.42, 13 November 2009, SI 618 PTRM-meters-Ver-RP2 (analysis sheet row 30).

Forecast capital expenditure

ETSA Utilities stated that it has removed the alternative control metering services forecast capex from its standard control PTRM and included these values in its alternative control services PTRM. ETSA Utilities noted that the forecast capex values are the same as those provided in its regulatory proposal.[1233] ETSA Utilities proposed forecast capex amounts are shown in table 17.2.

Table 17.2: ETSA Utilities forecast capex ($million, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Capital expenditure	11.9	13.4	12.6	14.1	14.4

Source: ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, SI 618 PTRM-meters-Ver-RP2 (assets sheet row 41).

Building block elements

ETSA Utilities stated that it has removed the alternative control metering services forecast opex from its standard control PTRM and included these values in its alternative control services PTRM. ETSA Utilities noted that the forecast opex values

[1231] ETSA Utilities stated that it did not make any adjustments to forecast capex and opex as it considered the impact of meter churn to be immaterial.

[1232] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, section 1, confidential.

[1233] The amounts differ to the extent that the AER's draft decision adjustments impact on the modelling of these forecast amounts.

are the same as those provided in its regulatory proposal.[1234] ETSA Utilities proposed forecast opex amounts are shown in table 17.3.

ETSA Utilities has applied a post–tax nominal WACC of 9.04 per cent to derive its return on capital building block amount.[1235] The proposed return on capital amounts are shown in table 17.3.

ETSA Utilities stated that the regulatory depreciation on its opening asset base is based on a 30 year asset life which is consistent with the current regulatory control period depreciation of the asset category LVS and metering services. ETSA Utilities stated that this approach ensures compliance with the NER. The asset life adopted for new meters in the next regulatory control period is 15 years.[1236] The proposed regulatory depreciation amounts are shown in table 17.3.

Table 17.3: ETSA Utilities building block revenue requirement ($million, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Return on capital	7.47	8.22	9.04	9.70	10.42
Return of capital	3.64	4.39	5.25	6.12	7.10
Opex	6.36	6.69	7.03	7.40	7.80
Tax	0.45	0.51	0.58	0.65	0.73

Source: ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, SI 618 PTRM-meters-Ver-RP2 (x factor sheet).

Tariff class and tariff component

ETSA Utilities stated that it had not changed the tariff class and tariff components in its regulatory proposal but had removed these from the standard control PTRM and applied them to the alternative control services PTRM.[1237]

Customer number forecasts

ETSA Utilities stated it calculated potential customer churn rates based on data since 2006 but its forecast customer numbers are proposed on a conservative approach. It proposed to estimate customer numbers by applying the churn rates to customers subject to only two tariff components, rather than to all customers. These components are: meter provision – standard multi phase, current transformer connected and meter provision – legacy type 1–4 meters.

ETSA Utilities stated that it used the meter customer number forecasts in its regulatory proposal and applied its churn rates to these forecasts to derive customer

[1234] The amounts differ to the extent that the AER’s draft decision adjustments impact on the modelling of these forecast amounts.

[1235] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, SI 618 PTRM, meters (input sheet J7), confidential.

[1236] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, section 1, confidential.

[1237] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, section 3, confidential; and ETSA Utilities, *Regulatory proposal*, July 2009, p. 273, attachment L2.

numbers for the next regulatory control period under the alternative control services WAPC.[1238] Proposed churn rates of 13.6 and 26.6 per cent is applied by ETSA Utilities for meter provision – standard multi phase current transformer connected and meter provision – legacy type 1–4 meters, respectively.[1239]

Indicative prices and X factor

ETSA Utilities stated that it will adopt the notional 2009–10 indicative prices in its regulatory proposal that incorporated the variable capital and operating costs associated with each of the tariff components.[1240] ETSA Utilities proposed to apply its P_0 adjustment to these notional prices to derive the alternative control metering services prices in the first year of the next regulatory control period.

Based on its alternative control metering services PTRM, ETSA Utilities proposed a P_0 adjustment and X factor of –9.28 per cent. Table 17.4 shows ETSA Utilities' proposed prices based on the application of its X factor.

Table 17.4: ETSA Utilities forecast prices – standing charge ($ per customer per year)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Meter provision 1 phase, 1 rate	6.5	7	8	9	10	11
Meter provision 1 phase, 1–2 rate controlled load/offpeak	20.0	22	25	28	31	35
Meter provision multi-phase direct connected	20.0	22	25	28	31	35
Meter provision multi-phase direct connected, controlled load/offpeak	42.0	47	53	59	66	74
Meter provision multi-phase CTC	91.0	102	114	128	143	160
Meter provision legacy type 1–4	325.0	364	408	456	511	572
Energy data service quarterly read	4.5	5	6	6	7	8

Source: ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, SI 618 PTRM-meters-Ver-RP2 (forecast revenue sheet).

Compliance with the WAPC

ETSA Utilities stated that the means of compliance with the alternative control mechanism will be the application of the formula as set out in its response and the relevant administrative mechanisms and timetables set out in the regulatory proposal.[1241]

[1238] Meter customer numbers are provided in ETSA Utilities' regulatory proposal, appendix L1 PTRM.
[1239] ETSA Utilities, response to information request AER EU. 42, 13 November 2009, section 4, confidential.
[1240] The derivation of these prices were shown in ETSA Utilities regulatory proposal RIN 45 and appendix L2.
[1241] ETSA Utilities, response to information requests AER EU. 42, 13 November 2009, section 8, confidential.

17.6.2 AER review process

Section 17.6.1 of this draft decision sets out the key aspects of the separate building block and WAPC proposed by ETSA Utilities. The AER notes that stakeholders have not had an opportunity to comment on ETSA Utilities alternative control service control mechanism and also ETSA Utilities has stated it may reconsider some of its underlying assumptions.

The AER will assess the building block components as part of its final distribution determination for ETSA Utilities based on the revised regulatory proposal and submissions from interested parties.

The AER notes compliance with the WAPC can be demonstrated by ETSA Utilities providing, as part of its pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC equation.

For the reasons stated above, in this draft decision the AER has determined that it is reasonable to allow ETSA Utilities to resubmit its separate alternative control services building block PTRM and WAPC as part of its revised regulatory proposal. The AER has therefore not assessed ETSA Utilities' alternative control metering services building block components, tariff components, forecast customer numbers or the X factor which forms the basis of the CPI–X form of control, provided during the assessment. Hence, the AER will set out its decision on the price terms contained in the WAPC formula in its final distribution determination for ETSA Utilities.

17.7 AER conclusion

The AER will apply the control mechanism set out in its framework and approach paper as expressed by the formula in section 17.3 of this draft decision. ETSA Utilities is required to demonstrate compliance with the WAPC by providing, as part of its pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC formula approved by the AER.

ETSA Utilities is required to resubmit its alternative control services control mechanism as part of its revised regulatory proposal and the AER will assess it as part of the final decision.

17.8 AER draft decision

In accordance with clause 6.12.1(12) of the NER, the control mechanism for alternative control services provided by ETSA Utilities is a weighted average price cap. The applicable WAPC formula is set out in section 17.3 of this draft decision.

In accordance with 6.12.1(13) of the NER, ETSA Utilities must demonstrate compliance with the control mechanism for alternative control services by providing, as part of its annual pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC equation.

Glossary

AASB	Australian Accounting Standards Board
ABS	Australian Bureau of Statistics
ACG	Allen Consulting Group
AEM	Access Economics Macro model
AFMA	Australian Financial Markets Association
AGL	AGL Energy Limited
AMI	Advanced Metering Infrastructure
AMP	asset management plan
ANSIO	Australian national state and industry outlook
ANZSIC	Australian and New Zealand Standard Industry Classifications
AOFM	Australian Office of Financial Management
AON Global	AON Global Risk Consulting
AON Risk Services	AON Risk Services Australia Ltd
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
ASIC	Australian standard industry classification
ASX	Australian Securities Exchange
AUD	Australian dollar
AWOTE	average weekly ordinary time earnings
BBI	Babcock Brown Infrastructure
BBIP	business based incentive program
bppa	basis points per annum
CAM	cost allocation method
CAPM	capital asset pricing model
CBD	central business district
CCTV	closed circuit television
CEG	Competition Economists Group
CEG Memorandum	CEG, *Data relevant to assessing the cost of debt – Memorandum*, August 2009.
CFC	Construction Forecasting Council
CGS	Commonwealth government securities

COTA	Council on the Ageing (SA) Inc, Seniors Voice
CPRS	carbon pollution reduction scheme
CRA	Charles River Associates
CRU	Commodities Research Unit
DGM	dividend growth model
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DMS	distribution management system
DRP	debt risk premium
DUET Group	Diversified Utility and Energy Trust
DUOS	distribution use of system
EBA	enterprise bargaining agreement
EBSS	efficiency benefit sharing scheme
ECCSA	Energy Consumers Coalition of South Australia
ECM	efficiency carryover mechanism
ECT	estimated corporate income tax
EDC	*Electricity Distribution Code of South Australia*
EDPD	electricity distribution price determination
EGW	electricity, gas and water
EIC	South Australian Electricity Industry Code
EISS	Electricity Industry Superannuation Scheme
ENA	Energy Networks Association
EPA	Environmental Protection Agency
EPO	Electricity Pricing Order
ESC	Essential Services Commission of Victorian
ESCOSA SORI	ESCOSA, *Statement of Regulatory Intent*, March 2007
EUAA	Energy Users Association of Australia
FBG	Fosters Brewing Group
FERC	Financial Expenditure Review Committee
Finity	Finity Consulting Pty Ltd
FMG	Fortescue Metals Group
FRC	full retail contestability
FTE	full time equivalent

FY	financial year
gamma	assumed utilisation of imputation credits
GDP	gross domestic product
GFC	global financial crisis
GOS	grade of service
GSL	guaranteed service levels
GSP	gross state product
Guideline 14	ESCOSA, *Excluded services regulation (distribution) – Electricity industry Guideline No. 14.*
GWh	gigawatt hour
HV	high voltage
IEEE	Institute of Electrical and Electronics Engineers
IPO	initial public offering
IT	information technology
IVRA	individual voluntary remuneration agreement
KPMG	KPMG Australia
kV	kilovolt, (one thousand volts)
kWh	kilowatt hour
LME	London Metal Exchange
LPI	labour price index
LV	low voltage
MAIFI	momentary average interruption frequency index
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 – McGrathNicol is an independent advisory firm specialising in Corporate Advisory, Forensic, Transaction Services and Corporate Recovery.
MED	major event day
MEPS	minimum energy performance standards
MFS	Maloney Field Service
MRP	market risk premium

MTN	medium term note
MVA	mega volt ampere
MW	mega watt, (one thousand kilowatts)
MWh	mega watt hour
NDSC	negotiated distribution service criteria
NEC	national electricity code
NEO	national electricity objective
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industry Research
NOC	network operations centre
NPV	net present value
NSP	network service provider
NTER	national tax equivalence regime
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Cooperation and Development
Officer and Bishop	Professor Robert Officer and Doctor Steven Bishop
OMS	outage management system
ORG	Office of the Regulator General (Victoria)
Origin	Origin Energy Retail Pty Limited
payout ratio	imputation credit payout ratio
PCB	Polychlorinated biphenyl
PLEC	Power Line Environment Committee
PoE	probability of exceedence
PTRM	post–tax revenue model
PV	photovoltaic
Qld DNSPs	Energex and Ergon Energy
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

ROLR	retailer of last resort
SA Energy Minister	the South Australia Minister for Energy, the Honourable Patrick Conlon, MP
SACOSS	South Australian Council of Social Service
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SEO	seasoned equity offering
SFG	Strategic Finance Group Consulting
SKM	Sinclair Knight Merz Pty Ltd
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.
SSF	service standards framework
STPIS	service target performance incentive scheme
Synergies	Synergies Economic Consulting
TEC	total employment contract
TFA	Toyota Finance Australia Ltd.
the WACC review	AER, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, May 2009.
theta	the utilisation rate of imputation credits
TNSP	transmission network service provider
TOU	time of use
Tribunal	Australian Competition Tribunal
TTEG	Trans Tasman Energy Group
TUOS	transmission use of system
UCW	UnitingCare Wesley
US	United States of America
USA	United States of America
USD	United States dollar
VAA	Value Advisor Associates
VCR	value of customer reliability

Victorian DNSPs	Victorian electricity DNSPs
WACC	weighted average cost of capital
WAPC	weighted average price cap
WCSR	Wage Classification Structure Review