Draft decision

Victorian electricity distribution network service providers

Distribution determination 2011–2015

June 2010

Request for submissions

This document sets out the Australian Energy Regulator's (AER) draft decision on its distribution determinations for CitiPower, Powercor, Jemena, SP AusNet and United Energy (the Victorian DNSPs) for the period 1 January 2011 to 31 December 2015.

The AER will hold a pre-determination conference on its draft decision on 17 June 2010 in Melbourne for the purpose of explaining its draft determinations and receiving oral submissions from interested parties. Interested parties can register to attend the pre–determination conference by emailing AERinquiry@aer.gov.au by 7 June 2010.

Interested parties are invited to make written submissions on issues regarding these draft distribution determinations, consultants' reports and revised proposals to the AER by 19 August 2010. The AER will deal with all information it receives in the distribution determination process, including submissions on the draft distribution determinations, in accordance with the ACCC/AER information policy. The policy is available at www.aer.gov.au.

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

Alternatively, submissions can be mailed to:

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

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

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

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

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

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Overview

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

This is the first electricity distribution determination made by the AER on the price control regime to apply to the Victorian DNSPs—CitiPower, Powercor, Jemena, SP AusNet and United Energy. The previous determination that applied to these DNSPs for the period 2006–10 was made by the Essential Services Commission of Victoria (ESCV).

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

Key expenditure drivers and considerations

A key feature of the regulatory framework applied previously by the ESCV, and continued by the AER under the national regulatory framework in this determination, is the reliance on financial incentives for businesses to operate efficiently. This 'revealed cost' approach involves allowing regulated businesses to retain the benefits of efficiency gains for a fixed period of time

The business's actual costs, as revealed through regulatory accounts, are taken to be the efficient costs and become the starting point for assessing the needs of the business to provide services in the forthcoming regulatory control period. In this way, efficiency gains that the businesses have made are passed back to consumers in the form of lower prices. This arrangement has been pivotal in the AER's assessment of the expenditure forecasts in the Victorian DNSPs' current regulatory proposals.

At the same time, the AER has adjusted regulated allowances for the effect of higher input costs, such as labour and materials, as well increases in the cost of capital to reflect expected tighter financial conditions in capital markets over the forthcoming period.

Setting

The Victorian DNSPs have each proposed increases in expenditure that significantly exceed what they have spent in the current 2006–10 regulatory control period and also compared to what was forecast in the current regulatory control period. Overall, the Victorian DNSPs expect that capital investment would need to rise by around 66 per cent compared to their actual spending in the current regulatory control period and operating expenditure would need to increase by 36 per cent on current levels in order to meet their operating and capital expenditure objectives of supplying network services in accordance with their obligations and meeting expected demand and changes to their underlying costs.

The factors governing this substantial increase appear similar to those raised by DNSPs in other jurisdictions, which include responding to higher peak demand from more energy intensive appliances, such as air conditioners, and the need to replace ageing assets in an environment of increasing input and material cost pressures. In addition, the Victorian DNSPs have highlighted the impact of climate change and its potential to result in an increased frequency of extreme weather events, which the Victorian DNSPs expect to become more evident in the forthcoming regulatory control period.

In this draft decision, the AER provides a full assessment of these proposals and claims. It should be noted that in previous price reviews the Victorian DNSPs made similar claims for substantial expenditure increases which the ESCV cut back significantly. The Victorian DNSPs' actual expenditure in the current regulatory control period was, on the whole, substantially below the benchmark level set by the ESCV.

Assessment approach

The approach of the AER is to begin its assessment of the Victorian DNSPs' proposals by having regard to historical performance (actual capital and operating cost expenditure) in comparison with that forecast, both in previous periods and in relation to that forecast over the forthcoming regulatory control period. This analysis suggests the Victorian DNSPs' past forecasts have been high relative to their actual expenditures over the past two regulatory control periods (10 years) and also relative to their allowed (benchmark) expenditures set by the ESCV. The Victorian DNSPs' actual expenditures have followed a relatively constant trend in contrast to the significant forecast increases proposed.

Overall this trend analysis, together with comparative benchmarking of Victorian DNSPs with DNSPs in other jurisdictions, shows that Victorian DNSPs compare very favourably to those in other states. This means that the revealed costs of the Victorian DNSPs are a sound base for determining the starting point for evaluating their regulatory proposals.

In addition, the Victorian DNSPs have maintained relatively high standards of service, in terms of reliability of supply compared to other jurisdictions. Further, the Victorian DNSPs' capital governance processes should lead to prudent and efficient expenditure, which is evident in their actual spending to date.

Capital expenditure

Against this background, the AER considered the case put by the Victorian DNSPs for increases or changes in requirements that would justify a large increase in capital expenditure over the forthcoming regulatory control period—a 66 per cent increase has been proposed or a total of $5.4 billion ($2010).

The AER's investigation has found that the models and estimation techniques individually employed by all the Victorian DNSPs to develop their forecasts cannot be relied upon to give an accurate estimation of future needs. The AER considered the proposals for substantial increases in the volume of network build (augmentation and replacement) as compared to actual historical outcomes. This conclusion takes account of the impact of increases in peak electricity demand.

The AER's consultants concurred with this view. They concluded a reasonable estimate of prudent and efficient investment should be relatively consistent with historical trends, with some allowance for increasing needs due to the ageing of the network and further demand growth.

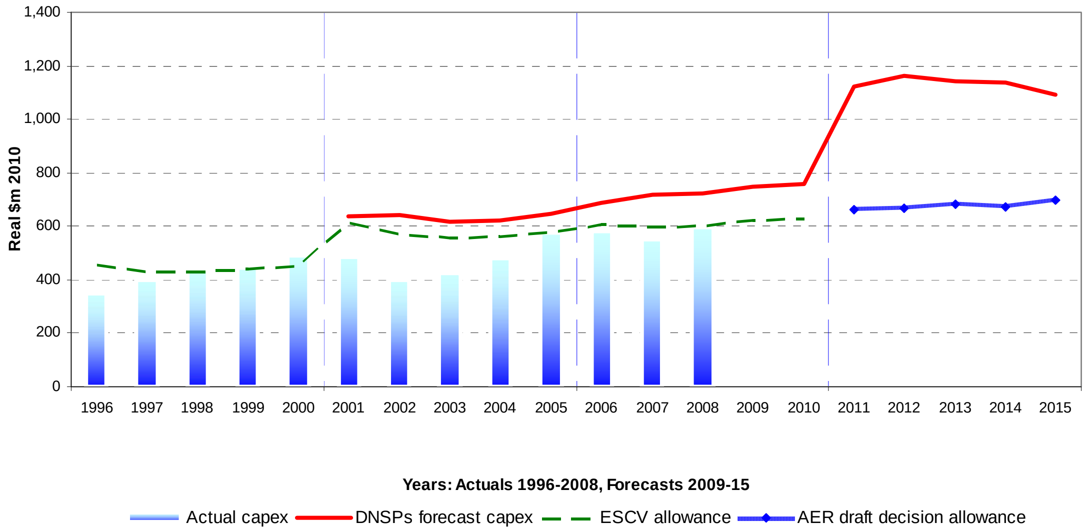
Similarly, the AER did not consider that the impact of climate change requires significantly enhanced measures that would justify substantial increases to network build or asset replacement. In this regard, the AER considers the Victorian DNSPs would be expected to maintain and expand their networks in a prudent way to mitigate such climatic effects as they have been doing already, and that this is reflective of their current pattern and level of network investment.

Therefore, the AER considers that capital expenditure should increase on average by around 16 per cent on actual expenditure in the current regulatory control period. Overall, the AER's decision means total capex would be $3.4 billion, around 38 per cent (or $2 billion) less than that sought by the DNSPs.

The AER notes that new obligations and expenditure requirements may eventuate in relation to bushfire mitigation, stemming from measures currently being considered by the Victorian Bushfires Royal Commission (VBRC). These obligations will ultimately be determined by the Victorian Government and will be dealt with under the regulatory framework as they arise, including through potential pass through events.

The AER's review nonetheless found, for SP AusNet and Powercor, that some increase in their conductor replacement activity would be prudent regardless of the outcome of the VBRC inquiry. This activity arises both for reasons of asset age and condition and because of the potential to reduce future potential fire risk. The AER therefore considers it would be appropriate to make some allowance for a prudent level of bushfire mitigation related expenditure for Powercor and SP AusNet, reflective of existing requirements.

Figure 1 Victorian DNSPs' current and forecast capex and AER draft decision capex forecast



Source: AER analysis.

Figure 1 provides an illustration of the Victorian DNSPs' actual and forecast expenditures over the past 10 years as well as their proposed expenditures for the forthcoming regulatory control period as discussed above. The outcome of the AER’s approach is that the capex allowance proposed in this draft decision closely follows the trend established by the ESCV in the current regulatory control period.

Operating expenditure

In general, the Victorian DNSPs will not be subject to new regulatory or legislative obligations, or changes to their operating environments, that have a material impact on operating expenditure over the forthcoming regulatory control period. The AER has rejected many of the Victorian DNSPs’ step change proposals ($293 million proposed, $44 million accepted) which included additional costs due to, among other things, climate change, insurance and regulatory matters. The AER has accepted that some new regulatory compliance costs will be borne by the Victorian DNSPs, including in respect of electrical safety, network planning and customer communications.

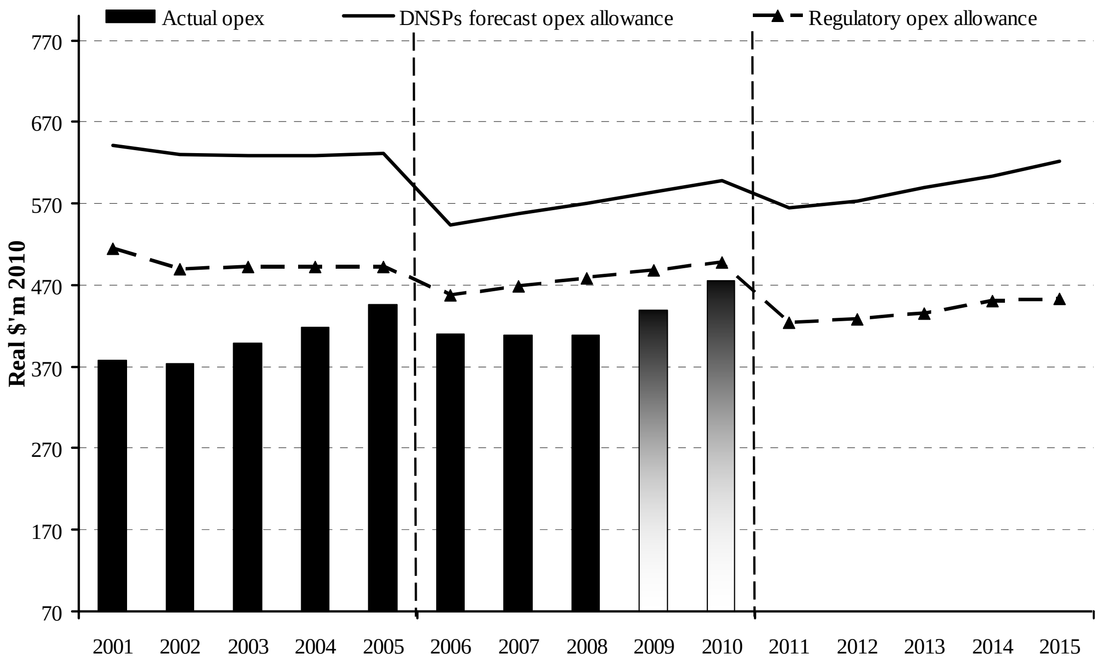
The Victorian DNSPs have proposed to maintain service performance consistent with current levels, and, as shown by advice from Nuttall Consulting, the impact of ageing assets is not considered to materially alter the existing opex profile necessary to maintain existing levels of service performance.

The distribution network will expand over the forthcoming regulatory control period, with the addition of new customers and assets. The AER has considered the impact on opex from growth (scale escalation) including expected productivity improvements and has allowed a modest increase in the Victorian DNSPs’ opex allowance in real terms (incorporating changes in real input costs for labour and materials). Further, while it is too early to evaluate the precise effect on efficiency from the use of advanced metering infrastructure (AMI—smart meters), the AER expects that such efficiencies will be evident over time and will impact on operating cost trends. Through its annual reporting framework, the AER will be monitoring the way AMI impacts on operating costs.

The AER considers that a total opex allowance of $2.2 billion over the forthcoming regulatory control period, an increase of around 2 per cent on actual levels in the current regulatory control period, is consistent with the regime. This compares to proposed increases sought by the Victorian DNSPs of around 38 per cent.

Figure 2 sets out the Victorian DNSPs’ current and forecast opex and the AER’s draft decision forecast opex.

Figure 2 Victorian DNSPs current and forecast opex and AER draft decision opex forecast



Source: AER analysis.

Conclusion

The Victorian DNSPs operate a mature and comparatively reliable network where asset performance and the operating environment is relatively stable, service performance is being maintained, and where the AER has not observed a material change in the Victorian DNSPs' regulatory obligations. The result, under a revealed cost approach, is an efficient level of base expenditure consistent with audited actual costs and a path of opex and capex that is expected to be relatively stable, with only modest increases from current levels, which is reflective of the continuity in regulatory outcomes and expectations. The decision incorporates continuing incentives for ongoing operating efficiency as well as maintenance and improvement in service performance where this is valued by customers.

As a result, the AER considered relatively modest increases in capital and operating expenditure were appropriate. This results in significant reductions in allowed revenues as compared to those sought by the Victorian DNSPs.

Total revenues and network charges

The AER’s draft decision would result in an average reduction in revenues of around 4.0 per cent in 2011 as compared to the preceding year. This largely reflects that Victorian DNSPs are currently earning revenues that are higher than forecast for the current regulatory control period due to sales volumes being substantially greater, and costs being substantially lower, than forecast at the time when prices were set in 2005. Taking account of the AER's assessment of efficient costs and current financial conditions, revenues and prices need to 'ratchet down' towards efficient costs from 2011. For the following years, allowed revenues will increase on average by 3.5 per cent per annum. This reflects additional capital expenditure and growth in operating expenditure during the period, including a higher cost of capital. These adjustments are offset to some extent by the reduction in costs arising from certain carryovers of efficiencies and service level factors from the current regulatory control period.

Table 1 AER draft decision expected revenues ($m, nominal)

	2010	2011	2012	2013	2014	2015
CitiPower	211.8	205.0	215.1	223.2	234.7	248.4
Powercor	426.7	413.1	434.8	458.3	481.3	502.4
Jemena	166.0	165.9	174.7	184.2	187.7	184.4
United Energy	296.2	249.5	262.1	281.0	303.5	332.2
SP AusNet	379.5	382.2	400.1	422.1	448.7	475.1
Total	**1480.2**	**1415.7**	**1486.8**	**1568.9**	**1655.8**	**1742.5**

As shown below, the AER's draft decision would result in changes to (nominal) network prices from 1 January 2011 ranging between a decrease of 17.5 per cent and an increase of 1.1 per cent, followed by an average annual increase ranging from 2.6 and 3.0 per cent. The indicative impact on retail prices is shown in table 3.

Table 2 Change in network prices (per cent, nominal)

	CitiPower	Powercor	Jemena	United Energy	SP AusNet
DNSP proposals					
2011	13.0	25.4	43.2	19.8	50.0
Average 2012–15	10.8	7.7	5.7	6.7	8.2
AER decision					
2011	–4.9	–5.8	1.1	–17.5	–2.0
Average 2012–15	3.6	2.6	0.3	5.1	2.6

Table 3 Retail price impacts (per cent, nominal)

	2011	Average annual change 2012–15
Proposals		
CitiPower	5.2	4.3
Powercor	10.2	3.1
Jemena	17.3	2.3
United Energy	7.9	2.7
SP AusNet	20.0	3.3
AER draft decision		
CitiPower	–2.0	1.4
Powercor	–2.3	1.0
Jemena	0.4	0.1
United Energy	–7.0	2.1
SP AusNet	–0.8	1.0

Table 4 Impact on annual residential bill ($, nominal)

	2011	Average annual change 2012–15
Proposals		
CitiPower	61.37	67.43
Powercor	121.35	50.90
Jemena	206.62	41.10
United Energy	104.20	42.10
SP AusNet	239.11	65.48
AER draft decision		
CitiPower	–23.44	17.32
Powercor	–27.73	12.10
Jemena	5.15	1.14
United Energy	–84.02	21.90
SP AusNet	–9.61	12.59

For the typical residential customer, the AER's draft decision would lead to a change in retail prices in nominal terms of between a 7.0 per cent decrease and a 0.4 per cent increase from January 2011 and small increases ranging from 0.1 per cent to 2.1 per cent on average for each of the remaining years of the forthcoming regulatory control period

In 2011, this equates to a change of between a reduction of $84.02 and an increase of $5.15, or an average reduction of nearly $28 across all Victorian DNSPs for a customer with an annual bill of $1200. For the remaining years of the regulatory control period, the average annual change in charges ranges from $1.14 and $21.90, or $13.01 across all DNSPs.

Summary

Introduction

This distribution determination relates to the five distribution network service providers (DNSPs) operating under licence within the State of Victoria—CitiPower Pty ABN 76 064 651 056 (CitiPower), Powercor Australia Ltd ABN 89 064 651 109 (Powercor), Jemena Electricity Networks (Vic) Ltd ABN 82 064 651 083 (Jemena), SPI Electricity Pty Ltd ABN 91 064 651 118 (SP AusNet), and United Energy Distribution Pty Limited ABN 70 064 651 029 (United Energy).

The Essential Services Commission of Victoria (ESCV) made the current regulatory determination for the five Victorian DNSPs for a five year period from 1 January 2006 to 31 December 2010 (the current regulatory control period).

The AER assumed responsibility for the economic regulation of electricity distribution services provided by Victorian DNSPs on 1 January 2009. The distribution determinations for the period 1 January 2011 to 31 December 2015 (the forthcoming regulatory control period) is the first for the Victorian DNSPs to be conducted by the AER under the National Electricity Rules (NER).

On 30 November 2009, the Victorian DNSPs submitted their regulatory proposals and proposed negotiating frameworks for the forthcoming 2011–15 regulatory control period to the AER. On 23 December 2009, the AER published the regulatory proposals and proposed negotiated distribution service criteria (NDSC) for Victorian DNSPs on its website. Interested parties were invited to make submissions on the proposals and 20 submissions were received. The Victorian DNSPs presented their regulatory proposals at a public forum held in Melbourne on 17 December 2009.

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

- Nuttall Consulting
- ACIL Tasman
- Access Economics
- Impaq Consulting

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 forthcoming regulatory control period
- the negotiation framework and NDSC that will apply to the Victorian DNSPs
- the schemes to provide incentives to the Victorian DNSPs to improve efficiency, maintain service standards and manage increasing demand
- an outline of the distribution determination outcomes monitoring framework that the AER intends to implement.

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 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 the Victorian DNSPs 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 DNSPs' control mechanism for standard control services
- set out the methodology for establishing the opening RAB
- assess the DNSPs' demand forecasts and cost inputs to achieve the capex and opex objectives
- set out the requirements for the DNSP's regulatory proposals, including the requirement to forecast capex and opex necessary to meet the capex and opex objectives
- 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 DNSPs' 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 AER's constituent decisions contained in this draft decision are reproduced in the draft distribution determinations.

Classification of services

Victorian DNSP regulatory proposals

All five Victorian DNSPs proposed changes to the classification of services specified in the Framework and approach paper. All five Victorian DNSPs submitted that connection and augmentation works for new connections should be classified as standard control services. Changes to the classification of the following services were proposed:

- fault level compliance service—CitiPower and Powercor proposed a change from alternative control to standard control
- specification and design enquiry—CitiPower and Powercor proposed a change from alternative control to standard control
- temporary supply services—CitiPower and Powercor proposed a change from alternative control to standard control
- location of underground cables—CitiPower and Powercor proposed a change from alternative control to standard control
- covering of low voltage mains for safety purposes—CitiPower and Powercor proposed a change from alternative control to standard control, SP AusNet proposed a change from fee based alternative control service to quoted alternative control service
- elective undergrounding—CitiPower and Powercor proposed a change from alternative control to standard control
- auditing design and construction—CitiPower and Powercor proposed a change from alternative control to standard control
- standard connections/routine connections—SP AusNet proposed these be classified as alternative control services, Jemena proposed that these be classified as standard control services
- reserve feeder—CitiPower and Powercor proposed that this be classified as a negotiated service
- provision of watchman lights and repair of watchman lights—CitiPower and Powercor proposed that these be classified as negotiated services
- meter investigation—CitiPower and Powercor proposed that this should be classified as an alternative control service (fee based)
- PV installation—CitiPower and Powercor proposed that this should be classified as an alternative control service (fee based)

- re-test of types 5 and 6 metering installations[1]—CitiPower and Powercor proposed that this be classified as unregulated
- damage to overhead service cables caused by high load vehicles—CitiPower, Powercor and SP AusNet proposed this should be classified as an alternative control service (quoted)
- high load escorts—lifting overhead lines—CitiPower and Powercor proposed that this be classified as a alternative control service (quoted).

AER conclusion

The AER accepts the Victorian DNSPs' proposal to classify new connections requiring augmentations as standard control services. The AER accepts the following proposed classification of services:

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

Chapter 2 and appendix A contain the AER's draft decision on the classification of distribution services for Victorian DNSPs.

Negotiated distribution services

Victorian DNSP regulatory proposals

Each Victorian DNSP submitted a proposed negotiating framework for the forthcoming regulatory control period.

[1] For first tier customers with annual consumption greater than 160 MWh.

AER conclusion

The NDSC to apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy for the forthcoming regulatory control period are set out in appendix D of this draft decision.

The AER approves the negotiating frameworks submitted by CitiPower and Powercor.

The AER does not approve the negotiating frameworks submitted by Jemena, SP AusNet and United Energy. The AER requires amendments to each of these negotiating frameworks as set out in appendix C of this draft decision. Chapter 3 contains the AER's draft decision on negotiated distribution services for Victorian DNSPs.

Price control formula for standard control services

Victorian DNSP regulatory proposals

The Victorian DNSPs proposed that the AER apply the control mechanisms for standard control services as set out in the AER's Framework and approach paper, subject to the variations set out below:

- Jemena, CitiPower and Powercor submitted that the Framework and approach paper did not detail the basis of calculation for the licence fee factor (L_t) that is applied in the weighted average price cap (WAPC) formula. They proposed that the AER adopt the formula set out in clause 2.3.15 of volume 2 of the 2006 Electricity Determination Price Review (EDPR) with appropriate modifications.

- The ESCV's S factor scheme will be closed out as part of the transition to the AER's STPIS. However, actual performance for 2010 will not be known until after the AER's final decision on the 2011–15 distribution determination has been made. Given this, Jemena, United Energy, CitiPower and Powercor proposed that a factor be incorporated into the WAPC formula in 2012 to true up for actual 2010 S factor scheme performance. The effect of the factor would remain until the end of the forthcoming regulatory control period and would not require an adjustment in the 2016–20 regulatory control period.

- SP AusNet proposed that actual 2010 performance be trued up through a pass through mechanism with a $0 materiality threshold.

Regarding the recovery of transmission use of system charges (TUOS), the Victorian DNSPs proposed that the AER largely apply the maximum transmission revenue (MTR) arrangements set out in chapter 3 of volume 2 of the 2006 EDPR.

  - Jemena proposed that a new factor be included in the MTR formula to enable DNSPs to recover costs associated with the premium feed-in tariff (PFIT). CitiPower and Powercor proposed that PFIT rebate costs be recovered through the G component of the MTR formula.

  - SP AusNet and United Energy noted that transmission connection charges do not fall within the definition of TUOS under the NER. Therefore transmission connection charges cannot be recovered through clause 6.18.7 of the NER and the MTR mechanism.

- CitiPower and Powercor proposed that inter-DNSP charges, avoided TUOS and distribution use of system (DUOS) payments to embedded generators, be recovered through the D and G components of the MTR formula respectively.

AER conclusion

The AER accepts Jemena's, CitiPower's and Powercor's proposal that the formula set out in clause 2.3.15 of volume 2 of the 2006 EDPR be adopted, with modifications taking into account how L_t is incorporated into the WAPC formula in the forthcoming regulatory control period.

The AER does not accept the proposal that a factor to true up for 2010 S factor scheme performance be incorporated into the WAPC formula as it is not consistent with the Framework and approach paper. The true up for 2010 performance will be implemented in the 2016–20 regulatory control period.

The AER has added an explicit qualitative term into the WAPC formula for any approved cost pass throughs consistent with the approach in the AER's NSW and SA distribution determinations.

The WAPC formula to apply to the Victorian DNSPs in the forthcoming regulatory control period is:

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

where a DNSP has *n distribution tariffs*, which each have up to *m distribution tariff components*, and where:

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

regulatory year "t-1" is the regulatory year immediately preceding regulatory year *"t"*;

regulatory year "t-2" is the regulatory year immediately preceding regulatory year *"t-1"*;

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

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

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

CPI_t is calculated as follows:

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

divided by

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the ABS for the September Quarter immediately preceding the start of regulatory year t-1;

minus one.

X_t is the value of X for year t of the regulatory control period as determined by the AER in chapter 18 of this draft decision ;

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

L_t is the licence fee pass through adjustment to be applied in regulatory year t in accordance with appendix E.2 of this draft decision; and

Pass through 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.

- The AER accepts the proposal that the MTR formula be applied with modifications in the forthcoming regulatory control period.
- The AER does not accept the proposal that costs associated with PFIT be recovered through the MTR mechanism.
- The AER agrees with the interpretation that transmission connection charges do not fall under the definition of TUOS under the NER and cannot be recovered under clause 6.18.7 of the NER (and therefore the MTR mechanism).
- The AER does not accept CitiPower's and Powercor's proposal that inter-DNSP charges and avoided TUOS and avoided distribution use of system (DUOS) payments to embedded generators be recovered through the MTR mechanism.
- The AER recognises that the definition of TUOS under the NER is to be the subject of a rule change proposal by the Victorian DNSPs.

Chapter 4 contains the AER's draft decision on the price control formula for standard control services for Victorian DNSPs.

Peak demand, energy consumption and customer forecast numbers

Victorian DNSP regulatory proposals

The Victorian DNSPs each engaged the National Institute of Economic and Industry Research (NIEIR) to prepare energy and customer number forecasts for their networks. NIEIR's reports for each DNSP were provided as attachments to their regulatory proposals.

NIEIR also prepared 'top down' maximum demand forecasts for each DNSP which in most cases were used as a cross check for the Victorian DNSPs' own 'bottom up' demand forecasts. In general, NIEIR's top down demand forecasts are based on macro variables, such as economic growth, air conditioner use and the likely impact of numerous government policy changes. The Victorian DNSPs' bottom up demand forecasts reflect information specific to particular areas of the network, such as expected large loads and particular growth rates.

Tables 5 to 9 summarise the Victorian DNSPs' maximum demand, energy and customer number forecasts.

Table 5 Summary CitiPower proposal—Growth forecasts[2]

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15
Maximum demand (MW)[a]	1 535	1 577	1 679	1 661	1 705	2.7%
Energy (GWh)	6 030	6 046	5 944	5 828	5 836	–0.8%
Customer numbers	316 243	321 189	324 686	328 584	334 914	1.4%

Source: CitiPower, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 32.
(a) Summation of non–coincident zone substation maximum demands.

Table 6 Summary of Powercor proposal—Growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15
Maximum demand (MW)[a]	2 666	2 739	2 804	2 857	2 919	2.3%
Energy (GWh)	10 700	10 643	10 465	10 307	10 290	–1.0%
Customer numbers	715 541	727 610	739 714	752 719	766 214	1.7%

Source: Powercor, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 32.
(a) Summation of demand at non–coincident zone substation and 22kV terminal station points of supply.

[2] Note that totals in all tables presented here may not add due to rounding.

Table 7 Summary of Jemena proposal—Growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15
Maximum demand (MW) [a]	1 002	1 027	1 051	1 077	1 093	2.2%
Energy (GWh)	4 246	4 201	4 105	4 024	4 011	–1.4%
Customer numbers	308 296	313 257	317 334	320 907	325 049	1.3%

Source: Jemena, *Regulatory Proposal 2011–15*, 30 November 2009, p. 64; Jemena PTRM.

(a) Network-coincident maximum demands based on 50 PoE.

Table 8 Summary of SP AusNet proposal—Growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15
Maximum demand (MW)	2 005	2 093	2 185	2 281	2 381	4.4%
Energy (GWh)	7 821	7 756	7 622	7 563	7 638	–0.6%
Customer numbers	634 190	644 899	654 309	663 159	672 912	1.5%

Source: SP AusNet, *Electricity Distribution Price Review, Regulatory Proposal*, November 2009, p. 77.

Table 9 Summary of United Energy proposal—Growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15
Maximum demand (MW) [a]	2 181	2 253	2 296	2 390	2 434	2.8%
Energy (GWh)	7 793	7 734	7 592	7 478	7 486	–1.0%
Customer numbers	630 194	634 296	637 563	641 373	646 457	0.6%

Source: United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, November 2009, pp. 193–194.

(a) Non–coincident maximum demand forecast at the network level, based on a 10 per cent PoE forecast.

AER conclusion

The AER considers that the maximum demand forecasts proposed by the Victorian DNSPs are not a realistic expectation of the demand forecast required to achieve the capex and opex objectives and hence are not appropriate to form amounts, values or inputs to the AER's determination. The AER also considers that the Victorian DNSPs' proposed energy consumption and customer number forecasts are not appropriate to form amounts, values or inputs to the AER's determination under clause 6.12.1(10) of the NER.

The AER has amended the Victorian DNSPs' demand and energy forecasts to remove assumed policy impacts for standby power, insulation subsidy and time of use (TOU) tariffs. The AER has also replaced the Victorian DNSPs' proposed population growth forecasts, which affect their energy and customer number forecasts. These amendments have been made based on the forecasts presented in the Victorian DNSPs' regulatory proposals, and are the minimum necessary amendments to enable the forecasts to be approved in accordance with the NER, as required by clause 6.12.3(f) of the NER.

In place of the Victorian DNSPs' proposed forecasts, this draft determination approves maximum demand forecasts for selected zone substations in each DNSP's network. The sum of each DNSP's zone substation forecasts are presented in tables 10 to 14. The AER's draft determinations on the energy consumption and customer number forecasts for each Victorian DNSP are also set out in these tables.

This draft decision requests that the Victorian DNSPs provide revised maximum demand, energy and customer number forecasts as part of their revised regulatory proposals, making the following amendments:

- update gross state product forecast inputs to reflect more recent economic conditions
- replace population growth forecast inputs with ABS Series B for Victoria, disaggregated by DNSP according to current proposal assumptions about each DNSP's regional contribution to Victorian population growth
- amend the carbon pollution reduction scheme (CPRS) policy assumption to delay the commencement of the CPRS by 6 months, to 1 January 2012.

Chapter 5 contains the AER's draft decision on peak demand, energy consumption and customer number forecasts for Victorian DNSPs.

Table 10 AER conclusion on growth forecasts—CitiPower

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 465	1 509	1 573	1 603	1 627
Energy consumption (GWh)	6 246	6 430	6 544	6 595	6 678
Customer numbers	316 243	321 189	324 686	328 584	334 914

Table 11 AER conclusion on growth forecasts—Powercor

	2011	2012	2013	2014	2015
Sum of coincident zone substations (MW)	2 327	2 437	2 569	2 669	2 747
Energy consumption (GWh)	11 163	11 463	11 764	11 994	12 151
Customer numbers	715 541	727 610	739 714	752 719	766 214

Table 12 AER conclusion on growth forecasts—Jemena

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 067	1 096	1 134	1 168	1 184
Energy consumption (GWh)	4 439	4 544	4 647	4 725	4 783
Customer numbers	308 296	313 257	317 334	320 907	325 049

Table 13 AER conclusion on growth forecasts—SP AusNet

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 858	1 928	2 032	2 125	2 212
Energy consumption (GWh)	8 187	8 345	8 543	8 796	9 039
Customer numbers	634 191	644 900	654 309	663 159	672 912

Table 14 AER conclusion on growth forecasts—United Energy

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	2 266	2 352	2 406	2 509	2 558
Energy consumption (GWh)	8 193	8 444	8 710	8 921	9 072
Customer numbers	630 196	634 300	637 565	641 377	646 461

Outsourcing and related party transactions

AER conclusion

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

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

The AER has developed a conceptual framework to assist it in assessing the Victorian DNSPs’ operating and capital expenditure forecasts against the requirements of the NER. In developing this framework, the AER has had regard to the Victorian DNSPs’ proposals, the AER’s previous approach in the Jemena Gas Network access arrangement draft decision, and the past regulatory debate on this issue.

The first stage of the AER’s framework is a ‘presumption threshold’ designed to be an initial filter to determine which contracts it is reasonable to presume reflect efficient costs and costs that would be incurred by a prudent operator, and which contracts it is not reasonable to presume reflect efficient costs or costs that would be incurred by a prudent operator. In undertaking this ‘presumption threshold’ assessment, the AER considers the two relevant considerations are:

- Did the service provider have an incentive to agree to non-arm’s length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

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

Where an arrangement ‘passes’ the presumption threshold, the AER considers the starting point for setting future expenditure allowances should be the contract price itself, with limited further examination required. This further examination involves checking whether the contract wholly relates to the relevant services (for example, standard control services) and whether the (efficient) contract price already compensates for risks or costs provided for elsewhere in the building blocks.

Where a contract fails the presumption threshold, the AER considers the starting point for setting future expenditure allowances should be the contractor’s actual costs,with a ‘margin’ above this level permitted only where the service provider is able to establish the efficiency and prudency of such a margin against legitimate economic reasons for the inclusion of the margin (and its quantum).

The AER identified some limited concerns with the tendering processes conducted by SP AusNet in its appointment of Tenix Alliance and by United Energy in its appointment of its ‘turn key service provider’ to replace Jemena Asset Management. However, the AER still considered that these arrangements passed the presumption threshold and so the AER can presume these arrangements reflect efficient costs that would be incurred by a prudent operator. Both these arrangements are with parties who are not related to the service provider.

The related party margins of each of the Victorian DNSPs did not pass the presumption threshold, and so the AER considered whether a margin above the related party's direct costs is appropriate. Two of the reasons the AER considers are legitimate economic reasons for the inclusion of a margin are:

- to compensate for a share of the contractor's corporate and other indirect costs
- to retain the benefit of historical efficiencies for a period of time.

That said, the AER's assessment has already factored the related party's corporate costs into the expenditure forecasts. The AER is also seeking to reward the Victorian DNSPs for the historical efficiencies realised by their related parties through the efficiency carryover mechanism (ECM) allowance. Accordingly, no additional 'margin' in the expenditure forecasts is required to compensate for these reasons.

Additionally, the AER has identified some issues with the corporate costs of the related parties of Jemena, SP AusNet and United Energy and has made adjustments to these costs. These issues include corporate costs not sufficiently connected to the provision of distribution services and management fees paid to parent companies that the AER is not satisfied reasonably reflect efficient costs incurred by a prudent operator.

The other legitimate economic justification for a margin is to compensate for the return on and return of capital invested in assets utilised by the related party contractors that are not already in the service provider's regulatory asset base (RAB). The AER is not aware of the existence of such assets. However, if particular Victorian DNSPs are able to demonstrate the existence of such assets in their revised proposal then the AER would allow in its final decision a margin to compensate for the return on and return of those assets.

Chapter 6 contains the AER's draft decision on outsourcing and related party transactions for Victorian DNSPs.

Forecast operating expenditure

Victorian DNSP regulatory proposals

The Victorian DNSPs' total forecast opex for the forthcoming regulatory control period is \$2 953 million (\$2010). This represents an increase of \$812 million, or 38 per cent above the Victorian DNSPs' expected actual opex of \$2 141 million (\$2010) in the current regulatory control period. Table 15 sets out each Victorian DNSP's forecast opex by cost category for the forthcoming regulatory control period.

Table 15 Victorian DNSP proposed opex for the forthcoming regulatory control period ($'m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
Network operating costs	47.6	197.0	59.5	291.2	160.6	755.9
Billing and revenue collection	15.9	27.7	17.2	4.0	10.0	74.8
Customer service	13.3	38.3	18.9	46.5	40.8	157.8
Advertising / marketing	0.3	0.5	5.8	11.3	4.3	22.1
Regulatory costs	9.2	21.0	14.7	6.6	10.5	62.0
Other network operating costs	6.9	17.2	89.2	160.1	227.1	500.5
GSL payments	–	12.1	0.1	19.7	0.3	32.2
Total operating costs	**93.1**	**313.8**	**205.4**	**539.4**	**453.6**	**1 605.4**
Routine maintenance	25.2	213.9	55.2	45.3	36.7	376.3
Condition based maintenance	55.3	182.3	34.4	189.7	53.0	514.8
Emergency maintenance	33.9	122.4	22.1	99.3	29.3	307.0
SCADA and network control	0.9	6.3	2.3	0.8	29.2	39.5
Other maintenance	13.9	29.9	–	–	–	43.9
Total maintenance	**129.2**	**554.9**	**114.1**	**335.1**	**148.2**	**1 281.5**
Debt raising costs[a]	21.6	33.5	–	19.9	–	75.0
Other[a]	–	–	–	–8.7	–	–8.7
Total opex	**244.0**	**902.3**	**319.4**	**885.7**	**601.8**	**2 953.2**

Source: Regulatory Information Notice, 30 November 2009, PTRM, 30 November 2009
(a) For further information refer to chapter 7

AER conclusion

The AER has considered the Victorian DNSPs' forecast opex and the AER is not satisfied that the total opex forecast proposed by each of the Victorian DNSPs reasonably reflects the opex criteria in the NER taking into account the opex factors.

Based on the AER's analysis of the Victorian DNSPs' regulatory proposals, submissions received and advice from Nuttall Consulting, the AER has applied a reduction of $763 million ($2010) to the Victorian DNSPs' forecast opex. This represents a reduction of around 26 per cent and results in a revised total opex forecast for the DNSPs of $2190 million ($2010).

The AER's estimate of each DNSP's required opex for the forthcoming regulatory control period is set out in Table 16 below.

Table 16 AER draft decision opex allowance for 2011–15 ($'m, 2010)

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

(a) DMIS, GSL

The AER considers this reduction is the minimum adjustment necessary to ensure the Victorian DNSPs' opex forecast meets the opex criteria. Chapter 7 contains the AER's draft decision on forecast opex for Victorian DNSPs.

Forecast capital expenditure

Victorian DNSP regulatory proposals

The Victorian DNSPs' total forecast capex for the forthcoming regulatory control period is $5406 million ($2010). This represents an increase of $2144 million, or 66 per cent from the DNSPs' expected actual capex of $3263 million ($2010) in the current regulatory control period. Table 17 sets out each Victorian DNSP's forecast capex by purpose for the forthcoming regulatory control period. For further information refer to chapter 8.

Table 17 Victorian DNSPs' proposed capex for the forthcoming regulatory control period ($'m, 2010)

	CitiPower	**Powercor**	**Jemena**	**SP AusNet**	**United Energy**	**Total**
System assets						
Demand related						
Reinforcement	229.4	241.5	143.3	321.2	205.0	**1 140.4**
Gross demand connections	379.1	673.7	138.2	357.0	214.4	**1 762.4**
Non-demand related						
Reliability and quality maintained	258.0	364.4	151.5	258.4	277.2	**1 309.4**
Reliability and quality improvements	0.0	0.0	0.0	0.0	0.0	**0.0**
Environmental, safety and legal obligations	16.0	48.2	27.0	94.9	51.1	**237.1**
Sub-total	**882.5**	**1 327.8**	**460.0**	**1 031.4**	**747.6**	**4 449.3**
Non-system assets						
SCADA & network control	18.1	30.6	3.1	7.4	4.7	**64.0**
Non-network general - IT	44.9	104.7	58.8	143.0	98.5	**449.9**
Non-network general – other	16.4	84.5	41.7	34.7	13.1	**190.4**
Sub-total	**79.4**	**219.9**	**103.5**	**185.2**	**116.3**	**704.2**
Total gross direct capex	**961.9**	**1 547.7**	**563.5**	**1 216.5**	**863.8**	**5 153.5**
Direct overheads	82.2	43.9	82.5*	81.4	0.0	**290.0**
Indirect overheads	83.2	125.0	–	81.4	0.0	**289.6**
Cost changes	63.5	95.7	23.2	76.3	47.0	**305.7**
Related party margins	39.8	58.3	–	4.9	0.0	**103.1**
Total gross capex	**1 230.7**	**1 870.6**	**669.2**	**1 460.5**	**910.9**	**6 141.9**
Less customer contributions	172.6	283.1	69.5	89.0	120.9	**735.1**
Total net capex	**1 058.1**	**1 587.5**	**599.7**	**1 371.5**	**790.0**	**5 406.9**

Source: Victorian DNSPs' RIN, 30 November 2009. *For confidentiality reasons, direct and indirect overheads and related party margins have been aggregated.

AER conclusion

The AER has considered the Victorian DNSPs' forecast capex and the AER is not satisfied that the total capex forecast proposed by each of the Victorian DNSPs reasonably reflects the capex criteria in the NER taking into account the capex factors. Based on the AER's analysis of the Victorian DNSPs' regulatory proposals, submissions received and advice from Nuttall Consulting, the AER has applied a reduction of $2 030 million ($2010) to the DNSPs' forecast capex. This represents a reduction of around 38 per cent and results in a revised total capex forecast for the DNSPs of $3 376 million ($2010). The AER considers that this reduction is the minimum adjustment necessary to ensure the Victorian DNSPs capex forecast meets the capex criteria. Chapter 8 contains the AER's draft decision on forecast capex for Victorian DNSPs. The AER's conclusion of each DNSP's required capex for the forthcoming regulatory control period is set out in table 18 below.

Table 18 AER conclusion on Victorian DNSPs' capex ($'m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
DNSP proposed capex	**1 058.1**	**1 587.5**	**599.7**	**1 371.5**	**790.0**	**5 406.9**
System assets						
Demand related						
Reinforcement	131.5	149.8	59.1	170.3	128.4	**639.2**
Gross demand connections	197.5	526.6	125.6	357.0	214.4	**1 421.1**
Non-demand related						
Reliability and quality maintained	137.2	256.4	66.5	240.9	140.1	**841.1**
Reliability and quality improvements	0.0	0.0	0.0	0.0	0.0	**0.0**
Environmental, safety and legal obligations	6.0	33.5	25.0	5.5	42.7	**112.7**
Sub-total	**472.3**	**966.4**	**276.2**	**773.7**	**525.5**	**3 014.0**
Non-system assets						
SCADA & network control	4.9	12.0	3.2	0.0	0.0	**20.1**
Non-network general - IT	24.2	59.1	47.3	72.0	98.5	**301.1**
Non-network general – other	16.4	40.0	16.8	18.2	13.2	**104.5**
Sub-total	**45.4**	**111.2**	**67.3**	**90.2**	**111.7**	**425.8**
Total gross direct capex	**517.7**	**1 077.5**	**343.5**	**863.9**	**637.2**	**3 439.9**
Direct overheads	43.6	26.6	6.7	59.1	0.0	**135.9**
Indirect overheads	74.2	117.2	14.4	75.9	0.0	**281.7**
Cost changes	40.3	78.9	6.8	66.7	15.3	**208.0**
Related party margins	0.0	0.0	0.0	0.0	0.0	**0.0**
Total gross capex	**675.8**	**1 300.2**	**371.5**	**1 065.6**	**652.4**	**4 065.5**
Less customer contributions	108.5	291.0	56.9	112.2	120.9	**689.4**
Total net capex	**567.4**	**1 009.2**	**314.6**	**953.3**	**531.5**	**3 376.1**
Adjustments	**–490.7**	**–578.3**	**–285.1**	**–418.2**	**–258.5**	**–2 030.8**
Adjustments (per cent)	**–46.4**	**–36.4**	**–47.5**	**–30.5**	**–32.7**	**–37.6**

Opening regulatory asset base

Victorian DNSP regulatory proposals

The Victorian DNSPs’ proposed roll-forward calculations for the 2006–10 regulatory control period are summarised in table 19.

Among the five Victorian DNSPs, only United Energy submitted a completed version of the AER’s published roll forward model (RFM) with its own adjustments. The other four DNSPs submitted their own RFMs.

Table 19 Victorian DNSP proposed RAB roll forward for the current regulatory control period ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 176.8	1 194.1	1 197.4	1 206.5	1 238.4
Net capex	93.6	79.0	84.7	102.4	124.7
Depreciation	–76.3	–75.7	–75.6	–70.5	–72.0
Compound return on 2005 capex difference					–
Closing RAB	1 194.1	1 197.4	1 206.5	1 238.4	1 291.0
Powercor					
Opening RAB	1 915.0	1 977.1	2 035.4	2 094.5	2 143.6
Net capex	182.3	179.1	181.5	174.0	199.1
Depreciation	–120.1	–120.9	–122.4	–124.9	–126.1
Compound return on 2005 capex difference					–
Closing RAB	1 977.1	2 035.4	2 094.5	2 143.6	2 216.6
Jemena					
Opening RAB	661.5	682.2	703.6	699.8	710.2
Net capex	64.0	66.3	41.9	57.3	92.8
Depreciation	–43.2	–44.9	–45.7	–46.9	–47.4
Compound return on 2005 capex difference					–
Closing RAB	682.2	703.6	699.8	710.2	755.6
SP AusNet					
Opening RAB	1 591.1	1 639.4	1 685.1	1 785.1	1 944.6
Net capex	132.8	138.7	199.1	263.8	256.1
Depreciation	–84.4	–93.0	–99.0	–104.3	–109.8
Compound return on 2005 capex difference					16.4
Closing RAB	1 639.4	1 685.1	1 785.1	1 944.6	2 107.3
United Energy					
Opening RAB	1 388.6	1 381.5	1 359.0	1 334.3	1 365.2
Net capex	97.7	83.9	85.4	124.4	124.9
Depreciation	–104.8	–106.4	–110.1	–93.4	–82.6
Compound return on 2005 capex difference					–
Closing RAB	1 381.5	1 359.0	1 334.3	1 365.2	1 407.5

Note: CitiPower, Powercor and United Energy submitted RFMs in real 2010 dollars. SP AusNet submitted its RFM both in real 2010 dollar and nominal terms. Jemena submitted RFM in real 2004 dollars, which has been converted to real 2010 dollars using its inflation adjustment, for purpose of comparison with the other DNSPs in the table.

Source: Victorian DNSP regulatory proposals, Attachment, RAB Roll Forward Model, November 2009.

AER conclusion

The AER has reviewed—including cross checks against their regulatory accounts—the Victorian DNSPs' proposed opening RABs and the inputs to the RFM for the current regulatory control period,. The AER has identified issues and made minor adjustments to the Victorian DNSPs' proposed opening RABs in relation to:

- reconciliation of data inputs
- adjustments arising from 2005 expenditure estimates
- escalation methodology for the RAB forward model
- financing costs for capex overspends during the current regulatory control period.

The AER has determined opening RAB values for the Victorian DNSPs which are set out in table 20. For this draft decision, the AER has applied:

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

Chapter 9 contains the AER's draft decision on the opening RAB values for Victorian DNSPs.

Table 20 AER conclusion on Victorian DNSPs' opening RAB ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 176.8	1 194.1	1 197.6	1 206.5	1 233.5
Net capex	93.6	79.1	84.6	97.5	124.7
Depreciation	–76.3	–75.7	–75.6	–70.5	–72.0
Compound return on 2005 capex difference					0.4
Closing RAB	1 194.1	1 197.6	1 206.5	1 233.5	1 286.5
Difference from proposed RAB					–4.5
Powercor					
Opening RAB	1 916.8	1 978.7	2 034.4	2 093.0	2 136.2
Net capex	182.0	176.5	181.0	168.2	199.1
Depreciation	–120.1	–120.9	–122.4	–124.9	–126.1
Compound return on 2005 capex difference					–4.3
Closing RAB	1 978.7	2 034.4	2 093.0	2 136.2	2 204.9
Difference from proposed RAB					–11.7
Jemena					
Opening RAB	653.4	673.9	695.0	691.1	708.3
Net capex	63.2	65.5	41.2	63.6	91.7
Depreciation	–42.7	–44.3	–45.1	–46.3	–46.8
Compound return on 2005 capex difference					–10.9
Closing RAB	673.9	695.0	691.1	708.3	742.2
Difference from proposed RAB					–13.4
SP AusNet					
Opening RAB	1 585.7	1 631.0	1 676.0	1 775.8	1 935.8
Net capex	129.3	137.6	198.2	263.8	256.1
Depreciation	–84.0	–92.5	–98.5	–103.7	–109.2
Compound return on 2005 capex difference					11.5
Closing RAB	1 631.0	1 676.0	1 775.8	1 935.8	2 094.2
Difference from proposed RAB					–13.1
United Energy					
Opening RAB	1388.6	1381.5	1359.0	1334.3	1365.1
Net capex	97.7	83.9	85.4	124.2	124.9
Depreciation	–104.8	–106.4	–110.1	–93.4	–82.6
Compound return on 2005 capex difference					–19.7
Closing RAB	1 381.5	1 359.0	1 334.3	1 365.1	1 387.7
Difference from proposed RAB					–19.8

Depreciation

Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed regulatory depreciation calculated from the post-tax revenue model (PTRM) is set out in table 21.

Table 21 Victorian DNSP proposed regulatory depreciation ($'m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	33.2	36.7	40.2	44.2	49.3	**203.5**
Powercor	64.3	72.7	81.2	90.3	101.5	**410.0**
Jemena	28.4	34.4	40.7	40.7	39.2	**183.4**
SP AusNet	95.9	62.6	70.1	74.6	64.9	**368.1**
United Energy	51.7	56.4	63.0	67.6	72.3	**310.5**

Source: DNSPs' PTRMs.

The Victorian DNSPs proposed to continue using the straight line methodology for calculating depreciation in relation to the opening RAB for the forthcoming regulatory control period.

Each Victorian DNSP proposed to maintain the same asset categories as those approved by the ESCV for the 2006–10 regulatory control period, with the addition of a new asset category for equity raising costs proposed by CitiPower, Powercor and Jemena.

The Victorian DNSPs' proposed regulatory asset categories and standard lives are set out in table 22.

Table 22 Standard asset lives

Asset Category	Jemena	CitiPower	Powercor	SP AusNet	United Energy
Subtransmission	47.3	50.0	50.0	45.0	60.0
Distribution system assets	46.8	49.0	51.0	50.0	35.6
Standard metering	N/A[3]	N/A	N/A	N/A	N/A
Public lighting	N/A	N/A	N/A	N/A	N/A
SCADA/Network control	30.5	13.0	13.0	5.0	5.0
Non-network general assets—IT	5.0	6.0	6.0	5.0	5.0
Non-network general assets—other	18.9	10.0	15.0	1.0	7.5
Equity raising costs	42.0	48.9	46.2		

Source: DNSPs' PTRMs.

AER conclusion

The AER has assessed each of the Victorian DNSPs' proposed asset life inputs to the PTRM that are used to calculate regulatory depreciation in accordance with the NER.

As a result of the required adjustments to the asset lives by CitiPower, Powercor, SP AusNet and United Energy, the AER considers that the depreciation schedules proposed by these DNSPs do not comply with the NER requirements and therefore has not approved the schedules.

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[3] Standard lives for new standard metering and public lighting assets are not applicable as these assets are no longer considered assets used to provide standard control services and hence are not included in the RAB. The DNSPs have maintained asset categories for standard metering and public lighting in order to calculate depreciation of these assets prior to them becoming excluded from the RAB. In its final decision, the ESCV stated that:

> To address the potential for stranded asset risk associated with accumulation meters with the mandated rollout of interval meters the Commission, consistent with the methodology proposed in its final framework and approach, will provide that the asset base for these meters installed prior to 1 January 2006 will remain in the regulated asset base for DUoS charges. The financing costs associated with these assets will continue to be recovered through distribution use of system tariffs.

The ESCV in its public lighting information sheet also stated that:

> With the disaggregation of the public lighting OMR charges from DUoS charges, the financing costs associated with public lighting assets in the distributor's asset base as at 1 January 2001 continue to be recovered through DUoS charges.

The AER has made some changes to the asset lives proposed by the DNSPs, although the asset lives still differ significantly across DNSPs due to inconsistencies in asset categorisation and a general departure from the notion of an underlying 'physical' asset base and associated values.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined the Victorian DNSPs' regulatory depreciation allowances for the forthcoming regulatory control period. The draft decision on regulatory depreciation is set out in table 23. Chapter 10 contains the AER's draft decision on the depreciation allowances for the Victorian DNSPs.

Table 23 AER conclusion on regulatory depreciation ($'m, nominal)

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

Cost of capital

Victorian DNSP regulatory proposals

In estimating the rate of return for their regulatory proposal, the Victorian DNSPs have applied a nominal WACC value of 10.86 per cent based on the indicative averaging period.[4] The parameters proposed by each of the Victorian DNSPs are shown in table 24. The proposed methods, values, parameters and credit ratings are consistent with the AER's Statement of Regulatory Intent (SORI) with the exception of the market risk premium (MRP). The SORI defines WACC parameter values and methods that must be used in a distribution determination for the purposes of setting a rate of return unless there is persuasive evidence for a departure.

[4] CitiPower, *Regulatory proposal*, 30 November 2009, p. 308; Jemena, *Regulatory proposal*, 30 November 2009, p. 163; Powercor, *Regulatory proposal*, 30 November 2009, p. 316; SP AusNet, *Regulatory proposal*, 30 November 2009, p. 303; and United Energy, *Regulatory proposal*, 30 November 2009, p. 138.

Table 24 Proposed WACC parameters

Parameter	CitiPower	Jemena	Powercor	SP AusNet	United Energy	SORI
Gearing level (debt/equity)	0.60	0.60	0.60	0.60	0.60	0.60
Nominal risk-free rate	10 year CGS	10 year CGS	10 year CGS	10 year CGS	10 year CGS	10 year CGS
Market risk premium	8%	8%	8%	8%	8%	6.5%
Equity beta	0.80	0.80	0.80	0.80	0.80	0.80
Credit rating level	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
Debt risk premium	[4.71%]	[4.71%]	[4.71%]	[4.71%]	[4.71%]	N/A
Expected inflation rate	[2.44]	[2.47]	[2.44]	[2.40]	[2.44]	N/A
Nominal WACC	[10.86%]	[10.86%]	[10.86%]	[10.86%]	[10.86%]	N/A

Source: CitiPower, *Regulatory proposal*, pp. 307–308; Jemena, *Regulatory proposal*, pp. 163–164; Powercor, *Regulatory proposal*, pp. 315–316; SP AusNet, *Regulatory proposal*, pp. 295 and 303; and United Energy, *Regulatory proposal*, pp. xxiv and 138.
Note: Numbers in brackets are indicative 'place holders' only.

The AER notes the Victorian DNSPs have adopted the methodology for forecasting inflation, as described in the final decision for the NSW and ACT distribution determinations.[5] However, the AER observes that only Jemena has calculated the inflation forecast figure correctly (see section 11.5.7). The AER also notes that the Victorian DNSPs have not adopted the AER's methodology for estimating the return on debt, as described in the final decision for the NSW and ACT distribution determinations (see section 11.5.6).[6]

AER conclusion

For this draft decision, the AER has determined a nominal vanilla WACC of 9.68 per cent for the Victorian DNSPs, which is lower than the 10.86 per cent proposed.[7] The difference owes to the AER:

5 CitiPower, *Regulatory proposal*, 30 November 2009, p. 307; Jemena, *Regulatory proposal*, 30 November 2009, p. 164; Powercor, *Regulatory proposal*, 30 November 2009, p. 315; SP AusNet, *Regulatory proposal*, 30 November 2009, p. 295; and United Energy, *Regulatory proposal*, 30 November 2009, p. xxiv.

6 CitiPower, *Regulatory proposal*, p. 299; Jemena, *Regulatory proposal*, p. 173; Powercor, *Regulatory proposal*, p. 307; SP AusNet, *Regulatory proposal*, pp. 296–297; and United Energy, *Regulatory proposal*, pp. 147–148.

7 See for example, Jemena, *Regulatory proposal*, p. 161.

- rejecting the Victorian DNSPs' proposed estimation of the debt risk premium (DRP) by considering only data from Bloomberg, which according to the AER's analysis would not meet the need for the return on debt to reflect the current cost of borrowings for comparable debt

- rejecting the proposed MRP of 8 per cent, on the basis that the Victorian DNSPs' proposals did not constitute persuasive evidence to depart from 6.5 per cent

- updating the nominal risk-free rate for a 15-day period ended 19 March 2010 (from 5.47 to 5.65 per cent).

Table 25 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and debt risk premium, based on the proposed averaging period, and the expected inflation rate at a time closer to its final determination. Chapter 11 contains the AER's draft decision on the cost of capital for Victorian DNSPs.

Table 25 AER conclusion on WACC parameters

Parameter	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Nominal risk-free rate	5.65%	5.65%	5.65%	5.65%	5.65%
Real risk-free rate	3.00%	3.00%	3.00%	3.00%	3.00%
Expected inflation rate	2.57%	2.57%	2.57%	2.57%	2.57%
Gearing level (debt/equity)	60%	60%	60%	60%	60%
Market risk premium	6.5%	6.5%	6.5%	6.5%	6.5%
Equity beta	0.8	0.8	0.8	0.8	0.8
Debt risk premium	3.25%	3.25%	3.25%	3.25%	3.25%
Nominal pre-tax return on debt	8.90%	8.90%	8.90%	8.90%	8.90%
Nominal pre-tax return on equity	10.85%	10.85%	10.85%	10.85%	10.85%
Nominal vanilla WACC	9.68%	9.68%	9.68%	9.68%	9.68%

Corporate income tax and imputation credits

Victorian DNSP regulatory proposals

Assumed utilisation of imputation credits (gamma)

- The Victorian DNSPs proposed a departure from the gamma value defined in the SORI. CitiPower, Powercor, SP AusNet and United Energy proposed a value of 0.5, while Jemena proposed a value of 0.2.[8]

- The Victorian DNSPs, in conjunction with ETSA Utilities, engaged Associate Professor Skeels to review the position taken by the AER with respect to the selection of theta (0.65) in the WACC review.

- Jemena provided reports by Professor Officer, Synergies and Mr Feros, a tax partner at Gilbert and Tobin to support its position on the imputation payout ratio (0.66) and theta (0.3).[9]

8 CitiPower Pty, *Regulatory proposal 2011–2015*, 30 November 2009, p. 307; Jemena Electricity Networks (Vic) Ltd, *Regulatory proposal 2011-15*, 30 November 2009, p. 176; Powercor Australia Limited, *Regulatory proposal 2011-15*, 30 November 2009, p. 314; SP AusNet, *Electricity Distribution Price Review 2011–2015 Regulatory proposal*, 30 November 2009, p. 300; and United Energy, *Regulatory proposal for Distribution prices and services January 2011 – December 2015*, 30 November 2009, p. 154.

9 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; and Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009.

Estimation of corporate income tax liability

In estimating corporate income tax liability for the forthcoming regulatory control period, each Victorian DNSP submitted tax roll forward models to the AER which calculated the closing and opening asset values for each year of the current regulatory control period as well as forecast values for the forthcoming regulatory control period.[10]

Each Victorian DNSP submitted a completed PTRM which calculates the tax building block for the DNSP. Table 26 shows the forecast annual tax building block for each Victorian DNSP from the regulatory proposals submitted to the AER.

Table 26 Victorian DNSP proposed annual forecast tax liability ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	10.5	11.3	11.3	11.8	13.2
Powercor	10.6	12.2	14.1	16.1	18.8
Jemena	12.5	7.7	9.6	9.9	10.1
SP AusNet	13.9	3.6	6.9	9.4	11.3
United Energy	6.8	8.3	9.9	12.8	14.7

Source: CitiPower, *Regulatory proposal*, 30 November 2009, p. 315; Powercor, *Regulatory proposal*, 30 November 2009, p. 323; SP AusNet, *Regulatory proposal*, 30 November 2009, p. 304; United Energy, *Regulatory proposal*, 30 November 2009, p. 150; and Jemena, *Regulatory proposal*, 30 November 2009, p. 175.

AER conclusion

The AER has estimated the corporate income tax allowance for each Victorian DNSP for the forthcoming regulatory control period in accordance with the formula and other relevant provisions in the NER.

The AER considers that the value of 0.65 is the most appropriate estimate of gamma based on the reliable evidence currently available and that the Victorian DNSPs have not demonstrated a material change in circumstances to justify a departure from this value.

The AER's draft decision also reflects recent amendments to tax legislation affecting diminishing value rates used for tax depreciation as well as changes to the expected statutory corporate income tax rate.

The value of the tax building block has also been affected by changes arising from other areas of the AER's draft decision, particularly in relation to capital expenditure, but various other factors affect forecast taxable income.

[10] Tax asset values for DNSP's were rolled forward and carried over from the ESCV's 2006–10 EDPR.

Using these inputs in the draft decision the AER has calculated the corporate income tax liability for the Victorian DNSPs as set out in table 27. Chapter 12 contains the AER's draft decision on corporate income tax and imputation credits for Victorian DNSPs.

Table 27 AER conclusion on corporate income tax liability ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	6.0	6.3	6.6	6.6	6.8
Powercor	7.7	8.6	9.2	9.8	10.6
Jemena	2.3	2.8	3.3	3.7	3.0
SP AusNet	8.2	3.5	4.4	4.3	3.8
United Energy	4.8	5.6	6.7	7.2	7.8

Efficiency carryover for 2006–10

Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed efficiency carryover calculations for the 2006–10 regulatory control period are summarised in table 28.

CitiPower acknowledged that it had a negative carryover amount from the current regulatory period, and it proposed a zero carryover under the net present value (NPV) approach.

Table 28 Victorian DNSPs proposed efficiency carryover amount, 2011–15 ($'m, 2010)

	2011	2012	2013	2014	Total
CitiPower	–	–	–	–	**–**
Powercor	28.3	24.5	5.8	–6.0	**52.6**
Jemena	19.6	13.6	15.7	0.7	**49.6**
SP AusNet	13.8	–22.0	–5.0	2.1	**–11.1**
United Energy	9.2	6.0	–1.6	–1.4	**12.2**

Source: CitiPower, *Regulatory proposal*, table 9.2, p. 256; Powercor, *Regulatory Proposal*, table 9.1, p. 262; Jemena, *Regulatory Proposal*, table 17.1, p. 209; SP AusNet, *Regulatory Proposal*, table 9.1, p. 256; United Energy, *Regulatory Proposal*, table 10.2, p. 164;

AER conclusion

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

- not applying a carryover for United Energy
- inclusion of the accrued negative carryover amounts arising from the 2001–05 regulatory control period for Powercor
- ex post adjustments to the benchmark allowance associated with network growth
- adjustments to the benchmark allowance and actual expenditure to ensure comparability between the benchmark allowance and actual expenditure
- other adjustments
- non recurrent costs that occur in the base year.

In accordance with clause 6.4.3(6) of the NER, the AER has applied ECM for Victorian DNSPs as set out in table 29. This value is used as an input to the PTRM for the purposes of determining the Victorian DNSPs' annual building block revenue requirement during the forthcoming regulatory control period. Chapter 13 contains the AER's draft decision on Victorian DNSPs' proposed carryover amounts.

Table 29 AER conclusion on the Victorian DNSPs' carryover amounts 2011–15 ($'m, 2010)

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

Source: AER calculation

Efficiency benefit sharing scheme

Victorian DNSP regulatory proposals

Jemena, SP AusNet and United Energy proposed adjustments for the consequences of changes in growth during the forthcoming regulatory control period.

The Victorian DNSPs between them proposed that the following costs be excluded from the EBSS:

- guaranteed service level (GSL) payments
- superannuation contributions
- debt and equity raising costs
- self insurance and insurance costs

- the demand management innovation allowance (DMIA)
- changes in classification of a service
- adjustments for changes in regulatory responsibilities
- proposed nominated pass through events not determined by the AER to be pass through events
- expenditure that meets all of the necessary requirements for an approved pass through event other than satisfying the materiality threshold.

AER conclusion

The AER will apply the EBSS in accordance with the framework and approach paper for the Victorian DNSPs in the forthcoming regulatory control period.

The AER will allow adjustments to EBSS calculations for the consequences of network growth in the forthcoming regulatory control period. For the purposes of calculating efficiency carryover amounts, forecast opex will be adjusted for the actual growth in line length, the number of distribution transformers and zone substations, and customer numbers experienced over the forthcoming regulatory control period using the network growth escalation method in appendix J.

The following opex cost categories will be excluded from the operation of the EBSS for the forthcoming regulatory control period in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS:

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

Chapter 14 contains the AER's draft decision on the application of the EBSS to Victorian DNSPs.

Service target performance incentive scheme

Victorian DNSP regulatory proposals

The Victorian DNSPs proposed that the AER apply the service target performance incentive scheme (STPIS) as set out in the AER's Framework and approach paper, subject to the variations set out below:

- All the Victorian DNSPs proposed to use the definition of MAIFI that applied under the ESCV's S factor scheme rather than the definition in the STPIS.

- All the Victorian DNSPs indicated in their regulatory proposals their intent to update their reliability targets to reflect 2009 actual performance data.

- SP AusNet and United Energy proposed to adjust their reliability targets to account for a projected change in environmental factors that they claimed would affect network performance during the forthcoming regulatory control period. Jemena proposed an adjustment to its forecast MAIFI targets due to climate change.

- United Energy proposed to adjust its targets for the effects of probabilistic planning, changes in the approach taken to forecast electricity demand and the secondary effects of the drought.

- SP AusNet proposed that no cap on revenue at risk be applied to the reliability component of the STPIS. United Energy proposed that a lower cap on revenue at risk of 3 per cent be applied to the reliability component of the STPIS.

- SP AusNet proposed that a MED threshold of 3.2 beta from the mean was appropriate as it would ensure that only extreme events were excluded from its reliability performance figures. Powercor proposed a MED threshold 3.1 beta from the mean as it considered this would ensure that expenditure efficiencies are not pursued at the expense of day-to-day system reliability.

- There was uncertainty about whether the existing GSL scheme would continue to apply in the 2011–15 regulatory control period. This has resulted in several differences in how the Victorian DNSPs proposed to forecast GSL payments in the forthcoming regulatory control period. Jemena also requested an exemption from the AER’s notice of planned interruptions GSL parameter.

- All the Victorian DNSPs proposed a methodology to close out the effects of the ESCV’s S factor scheme. The Victorian DNSPs also proposed a further true up in 2012 to account for the 2010 actual performance, which will not be known until after March 2011.

AER conclusion

The AER will apply the national STPIS to the Victorian DNSPs in the forthcoming regulatory control period. The AER’s draft decision on the application of the STPIS is as follows:

- The AER will apply the SAIDI, SAIFI and MAIFI parameters to the Victorian DNSPs, segmented by network types as set out in the STPIS. For transitional reasons, the AER will apply the definition of MAIFI discussed at section 15.7.8 of this draft decision.

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

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

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

The AER has determined the following major event day (MED) threshold to apply to the Victoria DNSPs:

- CitiPower 2.5 beta from the mean
- Powercor 2.8 beta from the mean
- SP AusNet 2.8 beta from the mean
- Jemena 2.5 beta from the mean
- United Energy 2.5 beta from the mean

The incentive rates to apply to each applicable parameter are set out in table 15.26 of this draft decision.

The GSL component of the STPIS will not apply while the ESCV's GSL scheme remains in place. In the event that the ESCV's GSL scheme is withdrawn, the AER will implement the GSL scheme in the STPIS once the jurisdictional scheme is withdrawn. The AER will include the forecast GSL payments under the ESCV GSL scheme as a line item in the opex allowance.

The AER has developed a consistent methodology to close out the effects of the ESCV's S factor scheme. In the 2016–20 distribution determination, the AER will perform a final reconciliation to account for actual 2010 performance under the ESCV's S factor scheme.

Chapter 15 contains the AER's draft decision on the application of the STPIS to Victorian DNSPs.

Pass through arrangements

Victorian DNSP regulatory proposals

The Victorian DNSPs proposed that the following events be included as nominated pass through events in the AER's distribution determination:

- transfer of non-pricing distribution regulatory arrangements to a national regulatory framework (CitiPower and Powercor)

- force majeure (Jemena and United Energy)
- change in safety regulations introduced by Energy Safe Victoria (ESV) (CitiPower and Powercor)
- changes in exposure limits (CitiPower and Powercor)
- wind farm connection costs (Powercor)
- recommendations arising from the Royal Commission into Victorian Bushfires event (Powercor)
- financial failure of a retailer (CitiPower, Powercor, Jemena and United Energy)
- declared retailer of last resort (CitiPower, Powercor, Jemena and United Energy)
- AEMO fees or charges (CitiPower and Powercor)
- emissions trading scheme (ETS) (CitiPower, Powercor, Jemena, United Energy)
- network extension for remote generation (Powercor)
- insurance event (Jemena)
- insurer credit risk event (Jemena)
- asbestos compensation (Jemena)
- general nominated pass through (CitiPower, Powercor, SP AusNet and United Energy)
- forced load shedding (despite the event being foreseeable, the cost and timing of such an event cannot be forecast, and the associated costs are uncontrollable. The event cannot be insured or self insured against)
- legal liability above an insurance cap (SP AusNet)
- S factor payout (SP AusNet)
- introduction of new regulatory obligations for vegetation management around powerlines (United Energy)
- changes to corporate income tax (United Energy)
- transfer of customer regulation to national regulatory framework (United Energy)
- national broadband network event (United Energy)
- climate change assumption being materially wrong (United Energy)
- changes to bushfire mitigation framework (United Energy)

- carbon pollution reduction scheme (SP AusNet)
- premium feed in tariff event (SP AusNet).

The Victorian DNSPs proposed the following materiality thresholds:

- CitiPower and Powercor—$5 million
- Jemena—$1 million
- SP AusNet—$250 000 for specific nominated pass through events and NER prescribed pass through events, and $1 million for general pass through events
- United Energy—$200 000 or administrative costs for specific nominated pass through events, and $3 million or one per cent of annual average revenue for general nominated pass through events and NER prescribed pass through events.

AER conclusion

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

- a declared retailer of last resort
- insurer credit risk
- insurance event (this replaces SP AusNet's legal liability above insurance cap event)
- The AER also includes an extra nominated pass through event—a natural disaster.

The AER will apply a materiality threshold of 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

Chapter 16 contains the AER's draft decision on pass through arrangements for Victorian DNSPs.

Demand management incentive scheme

Victorian DNSP regulatory proposals

All five DNSPs broadly supported the application of the demand management incentive scheme (DMIS), which consists of a demand management innovation allowance (DMIA) and a forgone revenue component, as set out in the AER's Framework and approach paper. Only United Energy proposed any alteration to the DMIS. It proposed that the capped amount of the DMIA should be increased to $10 million over the forthcoming regulatory control period.

AER conclusion

The AER will apply both the DMIA and the forgone revenue component of the DMIS to CitiPower, Powercor, Jemena, SP AusNet and United Energy. The AER rejects United Energy's submission that the DMIA should be increased to $10 million. The annual capped amount under the DMIA for each Victorian DNSP for the forthcoming regulatory control period is:

- CitiPower—$200 000 ($1 million over the regulatory control period)
- Powercor—$600 000 ($3 million over the regulatory control period)
- Jemena—$200 000 ($1 million over the regulatory control period)
- SP AusNet—$600 000 ($3 million over the regulatory control period)
- United Energy—$400 000 ($2 million over the regulatory control period).

Chapter 17 contains the AER's draft decision on the application of the DMIS to Victorian DNSPS.

Overall revenue requirements and X factors

Victorian DNSP regulatory proposals

The Victorian DNSPs' calculations of annual revenue requirements and X factors were contained in the completed PTRMs submitted as part of their regulatory proposals and summarised in tables 30 to 34.

The proposed X factors result in the net present value (NPV) of the annual revenue requirements and expected earnings being equal over the regulatory control period for all Victorian DNSPs.

Table 30 CitiPower proposed annual revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		33.20	36.67	40.21	44.18	49.25
Return on capital		140.16	159.73	181.58	204.25	226.83
Tax allowance		10.46	11.27	11.27	11.75	13.15
Operating expenditure		46.71	46.96	51.29	53.99	51.83
Carryover amounts		–	–	–	–	–
Annual revenue requirements		230.53	254.63	284.36	314.18	341.06
Expected revenues	208.46	235.21	259.79	281.95	305.95	339.03
Forecast CPI (per cent)		2.44	2.44	2.44	2.44	2.44
X factors (per cent)		–10.10	–8.00	–8.00	–8.00	–8.00

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

Table 31 Powercor proposed annual revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		64.27	72.68	81.24	90.30	101.48
Return on capital		240.63	268.82	296.94	326.74	358.92
Tax allowance		10.57	12.21	14.06	16.10	18.81
Operating expenditure		185.23	172.02	187.53	206.72	197.63
Carry–over amounts		28.99	25.75	6.28	–6.58	–
Annual revenue requirements		529.69	551.49	586.05	633.28	676.83
Expected revenues	416.89	522.52	557.89	590.66	628.54	678.53
Forecast CPI (per cent)		2.44	2.44	2.44	2.44	2.44
X factors (per cent)		–22.30	–5.00	–5.00	–5.00	–5.00

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

Table 32 Jemena proposed annual revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		28.37	34.38	40.74	40.72	39.18
Return on capital		82.06	93.57	105.28	115.68	124.87
Tax allowance		12.55	7.68	9.56	9.86	10.07
Operating expenditure		63.28	62.43	66.38	72.15	71.03
Carryover amounts		–	–	–	–	–
Annual revenue requirements		206.36	212.39	238.85	239.22	245.16
Expected revenues	158.19	213.88	219.07	224.90	234.07	247.56
Forecast CPI (per cent)		2.47	2.47	2.47	2.47	2.47
X factors (per cent)		–39.64	–3.00	–3.00	–3.00	–3.00

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

Table 33 SP AusNet proposed annual revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		95.9	62.6	70.1	74.6	64.9
Return on capital		228.8	249.0	277.4	302.8	329.0
Tax allowance		13.9	3.7	6.9	9.4	11.3
Operating expenditure		171.8	181.2	189.9	199.1	207.2
Carryover amounts		14.7	-20.2	-2.4	5.4	3.1
Annual revenue requirements		525.2	476.3	541.8	591.2	615.5
Expected revenues	369.4	516.3	517.4	527.2	566.2	618.6
Forecast CPI (per cent)		2.40	2.40	2.40	2.40	2.40
X factors (per cent)		–46.25	–5.50	–5.50	–5.50	–5.50

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

Table 34 United Energy proposed annual revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		51.73	56.42	62.96	67.02	72.34
Return on capital		152.84	167.93	181.80	194.92	206.04
Tax allowance		6.77	8.30	9.94	12.77	14.74
Operating expenditure		126.88	126.17	128.70	131.21	134.09
Carryover amounts		9.42	6.35	–1.69	–1.53	–
Annual revenue requirements		347.64	365.16	381.71	404.39	427.21
Forecast CPI (per cent)	292.46	348.93	367.21	382.11	400.44	426.36
X factors (per cent)		2.44	2.44	2.44	2.44	2.44
X factors (per cent)		–16.81	–4.00	–4.00	–4.00	–4.00

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

AER conclusion

Tables 35 and 36 summarise the AER’s draft decision on annual building block revenue requirement and X factors for the forthcoming regulatory control period. Chapter 18 contains the AER’s draft decision on the annual building block revenue requirement and X factors for Victorian DNSPs.

Table 35 AER draft decision on annual revenue requirements ($’m, nominal)

	2011	2012	2013	2014	2015
CitiPower	208.2	206.0	222.0	240.8	250.6
Powercor	422.7	439.8	453.8	483.3	485.0
Jemena	168.7	174.4	188.1	185.2	178.9
SP AusNet	452.2	379.4	414.2	451.7	407.1
United Energy	262.9	266.6	286.8	306.2	297.0

Table 36 AER draft decision on X factors (per cent)

	2011	2012	2013	2014	2015
CitiPower	7.27	0.00	0.00	–2.00	–2.00
Powercor	8.14	0.00	0.00	0.00	0.00
Jemena	1.46	0.00	0.00	3.00	6.00
SP AusNet	4.46	0.00	0.00	0.00	0.00
United Energy	19.57	0.00	–2.00	–3.00	–5.00

Public Lighting

Victorian DNSP regulatory proposals

The Victorian DNSPs proposed that public lighting should be regulated as an alternative control service, consistent with the AER's Framework and approach paper. The Victorian DNSPs applied the public lighting model developed by the AER in November 2009 when proposing charges.

AER conclusions

The AER accepted the Victorian DNSPs' classification of public lighting as an alternative control service.

Public lighting charges will be subject to a price cap.

The AER rejected the Victorian DNSPs' forecast public lighting opex and capex and rejected the proposed public lighting charges on the following grounds:

- forecast volumes of public lighting installations were not accepted
- forecast opex was not considered prudent and efficient
- forecast capex was considered not prudent and efficient
- selected public lighting inputs were not considered prudent and efficient
- a reduced cost of capital compared to that proposed.

Public lighting charges will be capped and adjusted for movements in CPI for each year of the forthcoming regulatory control period as part of the Victorian DNSPs' annual pricing proposals. Victorian DNSPs will be required to demonstrate compliance with the price cap.

The public lighting charges approved in this draft decision are listed in chapter 19.

Other alternative control services

Victorian DNSP regulatory proposals

The Framework and approach paper allowed the Victorian DNSPs some discretion in utilising bottom up and top down approaches to calculate proposed prices for fee based and quoted alternative control services in the 2011–15 regulatory control period. Accordingly, the Victorian DNSPs took differing approaches to calculating their proposed alternative control services prices, which resulted in large variations in proposed prices for similar services among the DNSPs.

The approaches to calculating prices for fee based services varied between a bottom up build up of the prices, to calculating prices using a top down approach with current prices as a starting point. The Victorian DNSPs also used different approaches in building up input costs for fee based services, for example some DNSPs used actual input costs (labour, materials) and times taken to perform services, while others made calculations based on external contractor prices where services are performed under contract.

For quoted services, CitiPower, Powercor and Jemena proposed a number of different labour rates to apply to different quoted services. SP AusNet proposed a large number of different hourly rates, while United Energy did not propose any hourly rates for quoted services. None of the Victorian DNSPs provided the AER with information on material costs for quoted services, however Jemena and SP AusNet identified that they proposed materials for quoted services be recovered at cost.

AER conclusion

In reviewing the proposed prices for fee based alternative control services, the AER considered the following:

- the differing cost build up and top down adjustment methodologies adopted by each Victorian DNSP
- recommendations made by Impaq Consulting on the labour, time and materials inputs into alternative control services prices
- profit margins incorporated into alternative control services prices, consistent with the AER's general approach to outsourced transactions outlined in chapter 6 of this draft decision
- labour and materials escalators applied in the Victorian DNSPs' proposed price paths
- Energy Users Coalition of Victoria's (EUCV) submission on the Victorian DNSPs' wages as compared to wages growth in the sector.

Based on this analysis, the AER has largely rejected the Victorian DNSPs' proposed prices for fee based services and labour rates for quoted services over the forthcoming regulatory control period.

The AER’s draft decisions on the Victorian DNSPs’ fee based and quoted services prices for 2011 are set out in appendix O. The AER’s draft decisions on the form of control for alternative control services prices are set out in chapter 20.

The AER’s draft decision is that compliance with the alternative control services control mechanisms will be demonstrated through an annual pricing proposal process.

Outcomes monitoring and compliance

The AER intends to establish a framework to monitor the outcome of the 2011–15 Victorian distribution determinations, and the Victorian DNSPs’ service levels delivered to their customers.

It is intended that the monitoring framework will include both financial and customer service measures. The financial measures will include measurements of the effectiveness of opex and capex expenditure through a number of monitoring and performance measures, as well as physical volumes of assets such as the number of new connections. The customer service outcome measures will include the traditional performance indicators in quality and reliability of supply, providing timely service to customers; as well as the monitoring of low supply reliability areas, and DNSPs’ performance in responding to major network events.

The required information will be collected annually through the issuing of a regulatory information notice (RIN) under section 28F(1)(a) of the NEL following the final Victorian distribution determinations. The AER will undertake specific consultation with relevant stakeholders to determine the final outcome measures for DNSPs to report against after the final Victorian distribution determinations. Chapter 21 outlines the AER’s outcomes monitoring framework that it intends to implement in the forthcoming regulatory control period.

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).

This distribution determination relates to the five DNSPs operating under licence within the State of Victoria—CitiPower Pty ABN 76 064 651 056 (CitiPower), Powercor Australia Ltd ABN 89 064 651 109 (Powercor), Jemena Electricity Networks (Vic) Ltd ABN 82 064 651 083 (Jemena), SPI Electricity Pty Ltd ABN 91 064 651 118 (SP AusNet), and United Energy Distribution ABN 70 064 651 029 (United Energy).

The Victorian DNSPs collectively own and operate the electricity distribution network in Victoria. The provision of distribution services by these DNSPs is currently regulated by the Essential Services Commission of Victoria (ESCV), in accordance with the *Electricity Determination Price Review* (EDPR) issued by the ESCV in October 2005 for the current regulatory control period 1 January 2006 to 31 December 2010, and subsequently amended in accordance with a decision of the Appeal Panel dated 17 February 2006.[2] The AER assumed responsibility for the economic regulation of the Victorian DNSPs on 1 January 2009. The AER is responsible for making a distribution determination for the Victorian DNSPs in accordance with the NER, for the forthcoming regulatory control period (1 January 2011 to 31 December 2015).

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 Victoria contained in chapters 9 and 11 of the NER. The AER's principal task is to set the revenues that the Victorian DNSPs can recover or prices that they can charge from the provision of direct control services for the 2011–15 regulatory control period.

On 30 November 2009, the Victorian DNSPs submitted their regulatory proposals and proposed negotiating frameworks for the 2011–15 regulatory control period to the AER. On 23 December 2009 the AER published the regulatory proposals and proposed negotiated distribution service criteria (NDSC) for the Victorian DNSPs on its website.

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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 the Victorian DNSPs, the relevant version of the NER is version 33, which was in effect on 12 November 2009.

2 ESCV, *EDPR, Final Decision Volume 1*, October 2006 and ESCV, *EDPR, Final Decision Volume 2*, October 2006.

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:

> …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.[3]

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:

> (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.[4]

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

3 NEL, section 7.
4 NEL, section 16.

(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 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 the Victorian DNSPs 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 Derogations

Chapter 9 of the NER contains Victorian specific derogations.

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

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

1.3 Transitional arrangements

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

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

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

Clause 11.17.4 required the AER to formulate Victorian specific cost allocation guidelines which were published on 26 June 2008.[5] As required under clause 11.17.5(a) of the NER, Victorian DNSPs submitted their proposed Cost Allocation Method by the time their building block proposals were submitted to the AER.

Clause 11.17.6 specifies that metering services dealt with under the Advanced Metering Infrastructure (AMI) Order in Council are not subject to regulation under a distribution determination published under chapter 6 of the NER. The AER published a separate budgets and charges determination in relation to AMI in October 2009.[6]

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

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

1.4 Review process

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

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

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

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

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

- **Submissions—**the AER received 20 submissions on the Victorian DNSPs' regulatory proposals or the AER's proposed NDSC. The submissions are listed in appendix A.

- **Assessment by technical experts—**the AER engaged Nuttall Consulting as a technical expert to advise it on a number of key aspects of the regulatory proposals.[7] The consultants provided independent advice to the AER on these matters, based on their reviews. The AER has considered this advice in making its draft distribution determination. The terms of reference guiding the consultants' review are set out as an appendix to its report.

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

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

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

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

- **Revised proposals—**to facilitate the preparation of revised regulatory proposals in response to this draft distribution determination, the AER has further consulted with the Victorian DNSPs regarding the development of a modified RIN, regulatory templates and guidelines which will be issued in conjunction with this decision.
- The AER's analysis and assessment of the Victorian DNSPs' regulatory proposals, submissions and consultants' advice is set out in this draft decision.

1.5 Structure of draft decision

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

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

1.6 Overview of the Victorian electricity distribution network

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

CitiPower

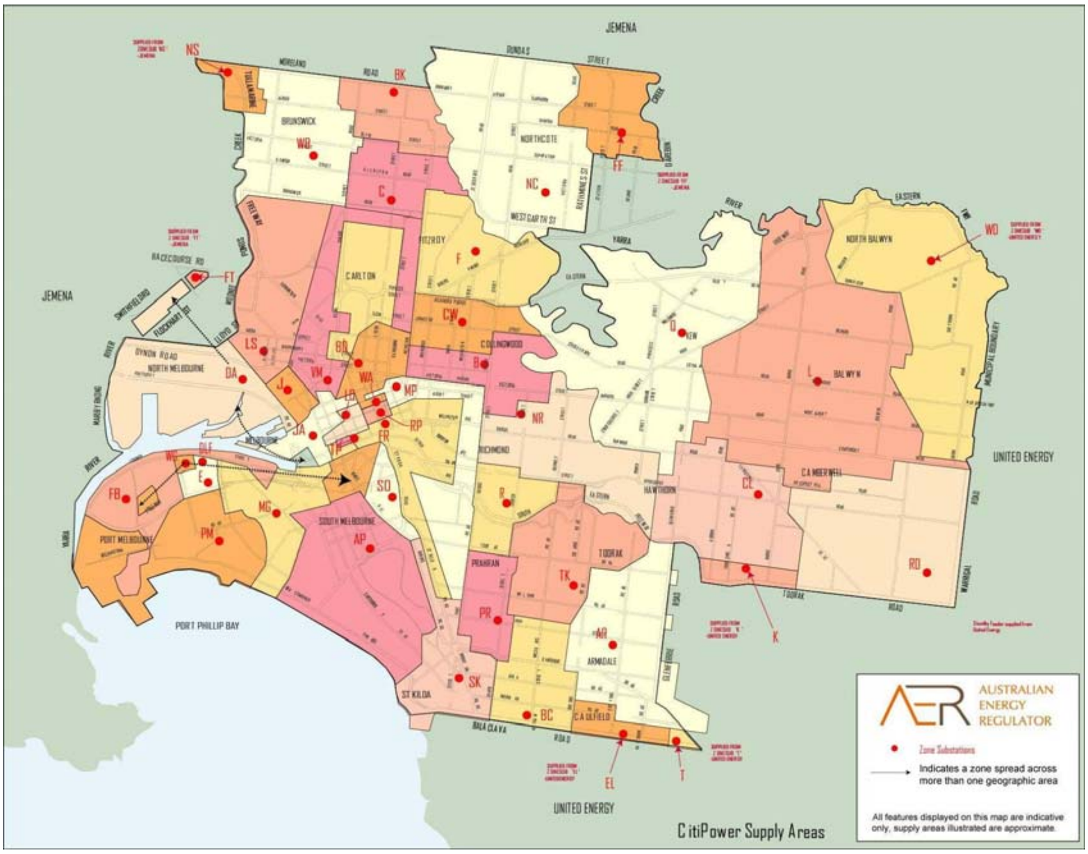
CitiPower supplies over 300 000 customers (about 83 per cent residential) in a 157km² area of Melbourne's CBD, docklands and inner city. Its network includes 6 500 km of powerline on 52 000 poles. About 17 per cent (by length) is classed as 'CBD', nearly 89 per cent of CBD lines are underground. It has common ownership

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

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

and a common management structure with Powercor. Figure 1.1 is a map of CitiPower's distribution network.[11]

Figure 1.1 CitiPower supply area map



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

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

Powercor

Powercor supplies nearly 680 000 customers (85 per cent residential) in 150 000km² of Victoria. Its network includes part of Melbourne's Docklands precinct, and extends from Williamstown, north to the Murray, west to the South Australian border and south to the coast. Powercor uses 83 000 km of powerline (65 per cent classified as 'rural') on 484 000 poles, and just over less than 5 per cent of its length runs underground. Figure 1.2 is a map of Powercor's distribution network.[12]

Figure 1.2 Powercor supply area map

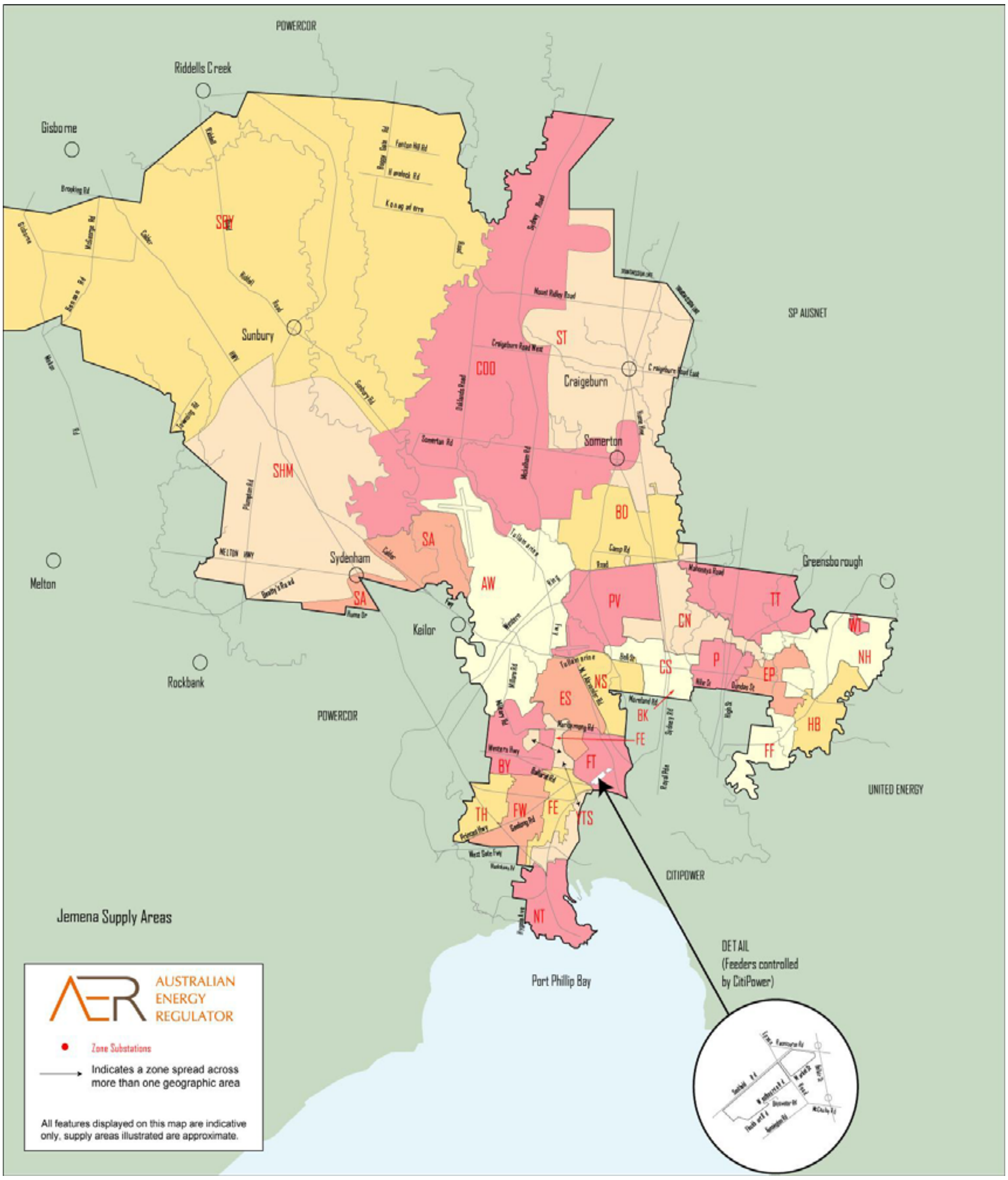
Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 117.

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

Jemena

Jemena supplies electricity to over 305 000 customers (91 per cent residential) in an 950km² area. This area covers Melbourne's city and north-western suburbs, with Tullamarine International Airport at the approximate centre.[13] Jemena supplies 12 per cent of Victorian customers and is the smallest of the five DNSPs in Victoria.[14] Figure 1.3 is a map of Jemena's distribution area.

Figure 1.3 Jemena supply area map



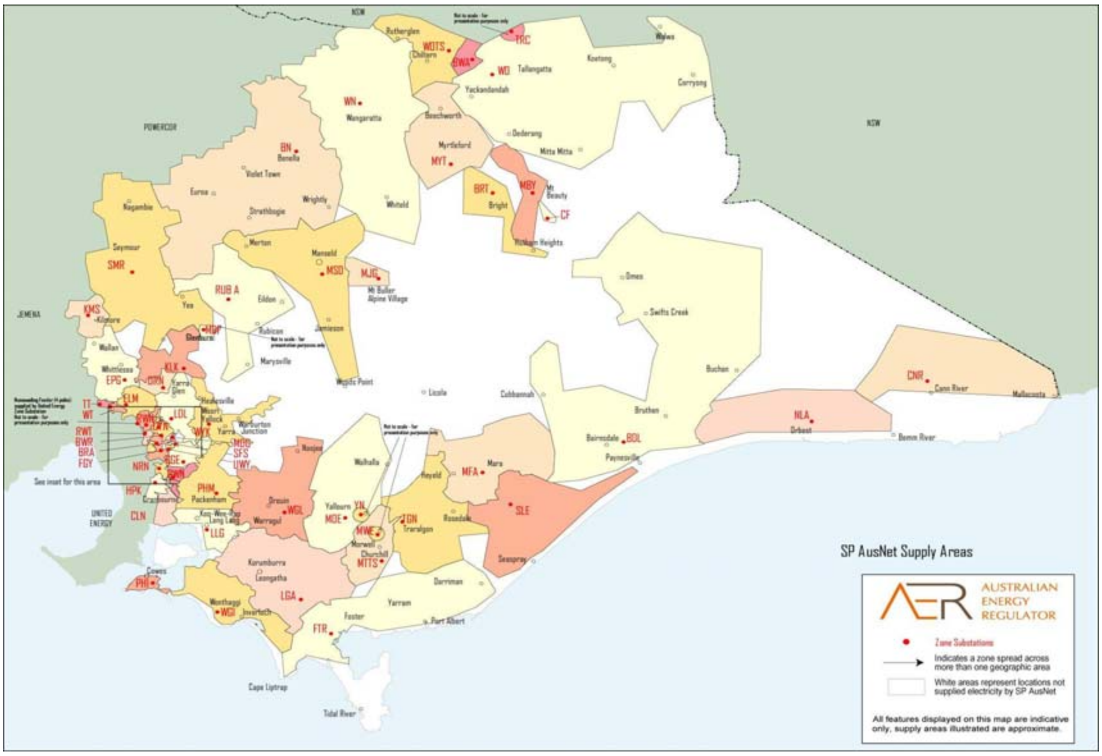
Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 113.

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

SP AusNet

SP AusNet's distribution network supplies 602 000 customers (88 per cent residential) in an 80 000km² area. This area extends from the fringe of the northern and eastern Melbourne metropolitan area, to the New South Wales border in the North, and to the Victorian coastline in the Southeast.[15] SP AusNet's distribution network assets include 47 66/22kV zone substations, 57 000 distribution substations, 371 000 power poles, 100 000 streetlights and 46 000 km of underground cable and overhead lines.[16] Its related companies also operate the electricity transmission network in Victoria. Figure 1.4 is a map of SP AusNet's distribution area.

Figure 1.4 SP AusNet supply area map



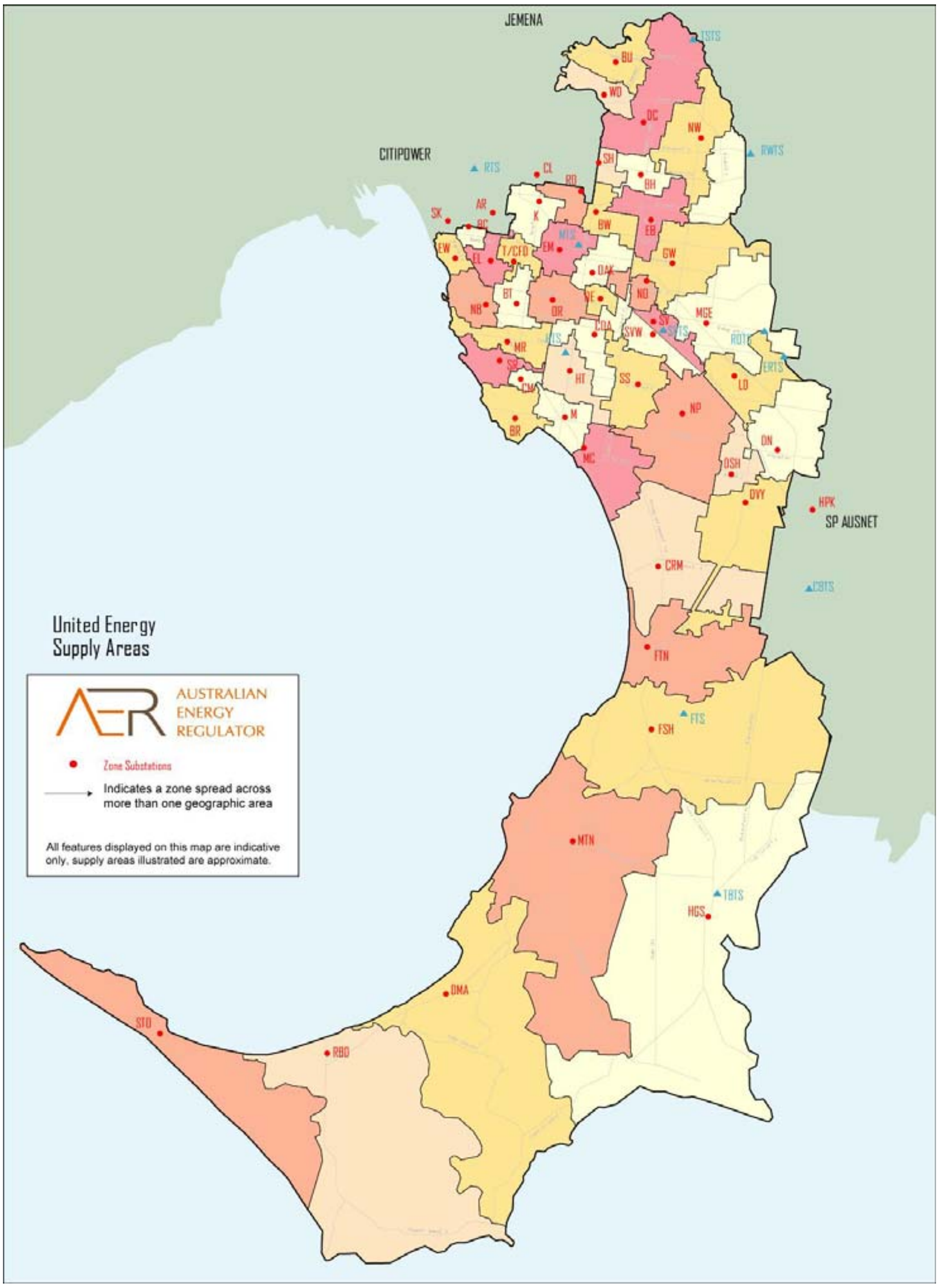
Source: AER, *Victorian electricity distribution businesses, Comparative performance report*, November 2009, p. 125.

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

United Energy

United Energy provides services to almost 630 000 end-use customers, located in an area of 1 472 km² in south-east Melbourne and the Mornington Peninsula.[17] Its distribution network comprises of 45 zone substations, approximately 208 000 poles, 11 500 distribution substations, 10 000km of overhead power lines and 2 300km of underground cables. Figure 1.5 is a map of United Energy's distribution area.

Figure 1.5 United Energy supply area map



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

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

2 Classification of services

2.1 Introduction

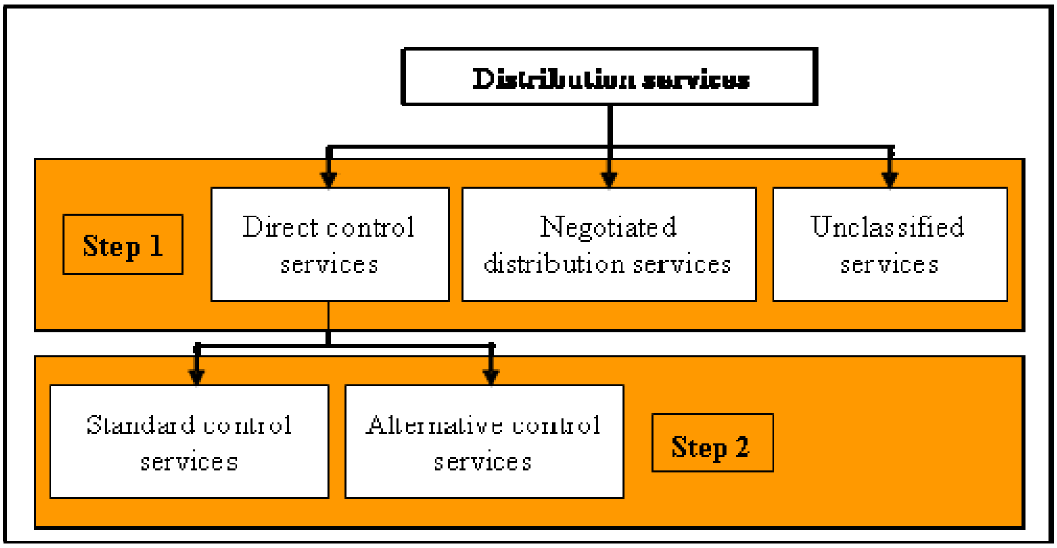
A distribution service is defined in the National Electricity Rules (NER) as a service provided by means of, or in connection with, a distribution network, together with connection assets, which is connected to another transmission or distribution system.[1] In accordance with clause 6.2.1 of the NER, the AER may classify distribution services as either:

- direct control services, or
- negotiated services.

If the AER chooses not to classify a service, it is not regulated under the NER.[2]

Direct control services are the most heavily regulated distribution services, and are subject to one of the control mechanisms in clause 6.2.5 of the NER. Negotiated services are subject to more light handed regulation under the NER through the negotiated distribution services criteria (NDSC) and negotiating framework approved by the AER.[3] Negotiated services are not included in the building block model applied to the regulation of direct standard control services. Unclassified services are not subject to economic regulation by the AER. Figure 2.1 demonstrates how services are classified under the NER.

Figure 2.1 Distribution service classification process



Source: NER, Chapter 6—Part B

1 NER, Chapter 10.
2 NER, cl. 6.2.1 (a).
3 For further information on the NDSC and negotiating framework, see chapter 3

2.2 Regulatory requirements

In classifying services, the AER must have regard to several factors outlined in the NER. Clause 6.2.1(d)(1) of the NER states that there should be no departure from the previous classification, and where there has been no previous classification, the classification should be consistent with the previous regulatory approach.

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

2.3 AER framework and approach paper

In its Framework and approach paper for CitiPower, Powercor, Jemena Electricity Networks (Jemena) SP AusNet and United Energy, the AER set out its likely approach to classification of services.[4]

In its Framework and approach paper, the AER's likely approach was to classify:

- certain prescribed distribution services currently provided by the Victorian DNSPs as standard control services, with all of these services being grouped as network services. This includes distribution use of system (DUOS) services
- certain excluded distribution services and prescribed metering services (unmetered supplies) currently provided by the Victorian DNSPs, as alternative control services, with these services being grouped in the following way:
  - connection services
  - metering services
  - public lighting services
  - fee based services
  - quoted services
- connection and augmentation works for new customer connections, alteration and relocation of existing DNSP public lighting assets, and new public lighting assets,

4 The classification of service must be as set out in the relevant framework and approach paper unless the AER considers that , in light of the DNSP's regulatory proposal and submissions received, there are good reasons for departing from the classification proposed in that paper (NER, cl. 6.12.3 (b)).

which are currently excluded distribution services, as negotiated distribution services.[5]

The AER notes that both 'fee based' and 'quoted' services are alternative control services under the NER. These sub categories were developed so that services of a similar nature could be grouped together. DNSPs will be able to levy charges for alternative control services (quoted and fee based) over the forthcoming regulatory control period on the basis of the AER's final decision on pricing and the control mechanism for these services. For fee based services the AER will determine a fixed fee whereas for quoted services the AER will determine the labour rate and basis for materials charges which can then be applied to the particular work which needs to be performed. Chapter 20 sets out the AER's draft decision on fee based and quoted alternative control services.

The AER’s indicative approach in its Framework and approach paper was to not classify certain other distribution services for the purposes of chapter 6 of the NER. These included advanced metering infrastructure (AMI) services. The regulatory arrangements relating to the AMI rollout are set out in an August 2007 Order in Council made by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000. An amending Order in Council was made on 25 November 2008 (the revised Order).’ According to the revised Order, metering provision services and metering data provision services for type 1 to 4 metering installations, metering services provided to customers with annual consumption greater than 160 MWh that have either type 5 manually read interval meters or type 6 manually read accumulation meters, and the installation and maintenance of watchman (security) lights. The AER is continuing this approach to classification in this draft determination.

The AER notes that this draft decision considers manual alternative control services only, and does not set prices for the Victorian DNSPs' remote metering services which are facilitated by the rollout of AMI in Victoria. The regulatory arrangements relating to the AMI rollout, and associated remote metering services charges, are set out in a legislative instrument that is separate to the NER.

2.4 Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs submitted the following proposed changes to the AER's Framework and approach paper service classifications.

New connections

All five Victorian DNSPs submitted that connection and augmentation works for new connections should be classified as standard control services.[6]

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5 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, pp. 3-4.

6 SP AusNet, *Electricity Distribution Price Review, Regulatory proposal*, November 2009, p. 28; CitiPower, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 12; Powercor, *Regulatory proposal 2011 to 2015*, 30 November 2009, p.14; Jemena, *Regulatory proposal 2011–2015*, 30

Standard connections/routine connections

SP AusNet submitted that standard connection services for new connections should be classified as alternative control services.[7] Jemena proposed that these services be classified as standard control services.[8]

Auditing design and construction

CitiPower and Powercor submitted that auditing design and construction services should be classified as standard control services.[9]

Specification and design enquiry

CitiPower and Powercor both submitted that specification and design enquiry services should be classified as standard control services.[10]

Temporary supply services

CitiPower and Powercor both submitted that temporary supply services should be classified as standard control services.[11]

Location of underground cables

CitiPower and Powercor both submitted that the location of underground cables should be classified as a standard control services.[12]

Covering of low voltage mains for safety purposes

CitiPower and Powercor both submitted that covering of low voltage mains for safety purposes should be classified as a standard control service.[13] SP AusNet proposed that the service should be classified as a quoted alternative control service (rather than a fee based alternative control service).[14]

Elective undergrounding where an above ground service currently exists

CitiPower and Powercor both submitted that elective undergrounding should be classified as a standard control service.[15] SP AusNet stated that these services should be classified as a quoted alternative control services.[16]

Fault level compliance service

CitiPower proposed that this new and previously unclassified service be classified as a standard control service.[17]

November 2009, p. 44; United Energy, *Regulatory Proposal for Distribution Services and Prices*, November 2009, p. 173.

7 SP AusNet, *Regulatory proposal*, p. 31.
8 Jemena, *Regulatory proposal*, p. 45.
9 CitiPower, *Regulatory proposal*, p. 19; Powercor, *Regulatory proposal*, p. 19.
10 ibid.
11 ibid.
12 CitiPower, *Regulatory proposal*, p. 20; Powercor, *Regulatory proposal*, p. 21.
13 CitiPower, *Regulatory proposal*, p. 19; Powercor, *Regulatory proposal*, p. 21.
14 SP AusNet, *Regulatory proposal*, p. 33; CitiPower, *Regulatory proposal*, pp. 27-28.
15 CitiPower, *Regulatory proposal*, p. 28; Powercor, *Regulatory proposal*, p. 28.
16 SP AusNet, *Regulatory proposal*, p. 33.

Reserve feeder

CitiPower and Powercor noted that the AER's Framework and approach paper did not classify the reserve feeder service. CitiPower and Powercor both considered that this service should be classified as a negotiated service.[18]

Provision of watchman lights

CitiPower and Powercor stated that the AER's Framework and approach paper did not consider the provision of new watchman (security) lights. Both parties proposed that new watchman (security) lights be classified as a negotiated service.[19]

Repair of watchman lights

Both CitiPower and Powercor submitted that this service should also be classified as a negotiated service.[20]

Meter investigation

CitiPower and Powercor both noted that the AER had not classified metering investigation services in the Framework and approach paper.[21] Metering investigation services are undertaken for connection points where requested by a retailer. CitiPower and Powercor proposed that this service be regulated as an alternative control service (fee based).[22]

Special meter reading

CitiPower and Powercor both noted that the AER had not classified special meter reading services in the Framework and approach paper, and that these services are not classified in the Advanced Metering Infrastructure (AMI) determination.[23]

Photovoltaic (PV) installation

CitiPower and Powercor submitted that the AER's Framework and approach paper did not classify PV installation services.[24] CitiPower and Powercor submitted that these services should be treated as alternative control services (fee based).[25]

Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh

CitiPower and Powercor both submitted that re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh should be unregulated.[26]

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17 CitiPower, *Regulatory proposal*, p. 28; Powercor, *Regulatory proposal*, p. 28.
18 ibid.
19 ibid.
20 CitiPower, *Regulatory proposal*, p. 23; Powercor, *Regulatory proposal*, p. 23.
21 CitiPower, *Regulatory proposal*, p. 24; Powercor, *Regulatory proposal*, p. 24.
22 CitiPower, *Regulatory proposal*, p. 25; Powercor, *Regulatory proposal*, p. 24.
23 CitiPower, *Regulatory proposal*, p. 25; Powercor, *Regulatory proposal*, pp. 26–27.
24 CitiPower, *Regulatory proposal*, p. 27; Powercor, *Regulatory proposal*, p. 27.
25 ibid.
26 CitiPower, *Regulatory proposal*, p. 29; Powercor, *Regulatory proposal*, pp. 28–29.

Energisation of new connections

CitiPower and Powercor stated that whilst no discrete classification for the energisation of new connections is required, should the AER continue to classify energisation of new connections as a separate service, then the appropriate classification is as an alternative control service (fee based).[27]

Repair of damage to overhead service cables caused by high load vehicles

CitiPower, Powercor and SP AusNet proposed that repair of damage to overhead service cables should be classified as a quoted alternative control service.[28]

High load escorts—lifting overhead lines

CitiPower and Powercor proposed that high load escorts should be classified as a quoted alternative control service.[29]

2.5 Summary of submissions

The AER received two submissions in relation to service classification, from:

- Origin Energy
- Central Victorian Greenhouse Alliance (CVGA)

Origin Energy

Origin Energy expressed concern about the continued operation of ESCV Guideline 14 in Victoria, and stated that it was preferable to modify and adapt the framework for capital contributions within the NER. It stated that Guideline 14 and the NER are difficult to integrate because:

- while the standard direct control classification may allow the DNSP to earn a return on capital, the classification is inappropriate under the NER, as it is directly attributable to an individual user and is contestable; and
- Jemena's approach to setting customer contributions for routine new connections is difficult to reconcile with the NER. This is because it is unclear on what basis the AER should approve a schedule of prices when clause 6.2.6(a) of the NER requires the control mechanism for standard direct control services to be of the CPI-X form within the price cap.[30]

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27 CitiPower, *Regulatory proposal*, p. 20; Powercor, *Regulatory proposal*, p. 20.
28 CitiPower, *Regulatory proposal*, p. 29; Powercor *Regulatory proposal*, p. 27; SP AusNet, *Regulatory proposal*, p. 35.
29 CitiPower, *Regulatory proposal*, p. 30; Powercor, *Regulatory proposal*, p. 29.
30 Origin Energy, *Re: Victorian DNSPs regulatory proposals*, 11 February, p. 2.

Central Victorian Greenhouse Alliance

CVGA submitted that a new customer connection requires an augmentation to the distribution network, and hence they should not be classified as negotiated services, but rather, as direct control services.[31]

CVGA expressed concern that, where distributed sustainable generation projects are created in order to alleviate network demands, the cost of any augmentation of the shared network would be charged to that project. This would create a major barrier to distributed sustainable generation projects.[32] The CVGA noted that:

> adding embedded generation to a feeder is likely to be able to defer augmentation of the shared network. It seems incongruous, therefore, that the costs of augmenting the shared network should be fully charged against the very projects that are striving to avoid or defer the augmentation of the network.[33]

Citelum

The AER also held a meeting with Citelum in March 2010 (for further information see chapter 19 Alternative Control Services—Public lighting).[34] Citelum sought to understand whether councils could contract with a separate entity, such as Citelum, to install new public lights on a DNSP's existing distribution power poles (not public lighting poles).

2.6 Issues and AER considerations

2.6.1 New connections requiring augmentation works

These connections require an augmentation or extension to the distribution network, in order to connect the customer. That is, capital works need to be undertaken in order to provide the connection. The cost associated with these services cannot always be fully recovered through the customer's supply and usage tariff over the life of the new assets installed to facilitate that connection. In these circumstances, customers are required to pay an upfront financial contribution (the quantum of which is regulated under ESCV Guideline 14). In the Framework and approach paper, the AER classified these services as negotiated services under the NER.

CitiPower and Powercor made the following comments on this service:

- the AER is required to classify 'services', but the proposed classification seeks to classify 'works'. The classification of 'works' is not permitted under the Rules. The AER must identify the relevant services that are provided to customers in relation to 'connection and augmentation works' and then classify those services.

- classification of these services as a Negotiated Distribution Service will also mean that the DNSP may be unable to recover the shortfall between the cost of

[31] CVGA, *Submission to AER – 2011 Victorian electricity distribution price review*, p. 5.
[32] ibid., pp. 6-7.
[33] CVGA, *Submission to AER*, p. 6.
[34] Meeting between Citelum staff and AER staff on 13 April 2010.

providing the service and the maximum amount that can be charged to customers under the ESCV's Electricity Guideline 14 (Guideline 14).[35]

CitiPower and Powercor also submitted that the classification of connection and augmentation works for new connections as negotiated services was inconsistent with the continued application of Guideline 14.[36] On this issue, both CitiPower and Powercor stated that:

> In particular, the ESCV's Guideline 14 limits the amount of the costs of providing these services that CitiPower can recover from the customer. It will not be possible for CitiPower to comply with the ESCV's Guideline 14 and also to comply with the requirements in the Negotiated Distribution Service principles in clause 6.7.1 of the Rules, which would require CitiPower to charge the customer the full costs incurred in providing the service.[37]

Jemena proposed to classify connection and augmentation works for new connections as standard control services, stating that this was consistent with the current classification in Victoria. Jemena stated that the AER's proposed classification as negotiated distribution services:

- is inconsistent with previous arrangements
- creates unnecessary administrative burden on Jemena and its customers
- could result in all customers paying at the outset the full cost of connection assets through connection charges, rather than through a combination of connection charges and ongoing network charges.[38]

SP AusNet noted that the Victorian Government has clarified that the Victorian arrangements governing customer connection should continue to apply for the forthcoming regulatory control period and that capital contributions made by the customer will continue to be subject to regulation under Guideline 14. Further, SP AusNet noted that:

- the Framework and approach paper classification prevents a DNSP including the net capital costs in the regulated asset base and recovering these costs through standard control charges
- the Victorian arrangements and specifically Guideline 14, prevent a DNSP from recovering the capital costs of connections (net of the allowed customer contribution) through unregulated charges outside of DUOS charges.[39]

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35 CitiPower, *Regulatory proposal*, p. 12; Powercor, *Regulatory proposal*, pp. 14-15
Guideline 14 is the ESC instrument that applies to the economic regulation of excluded services in Victoria, and how customer contributions are to be calculated for new works and augmentations. Guideline 14 also sets out arrangements for contestability of new connection and augmentation works.

36 CitiPower, *Regulatory proposal*, p. 12; Powercor, *Regulatory proposal*, p. 14.

37 CitiPower *Regulatory proposal*, p. 14; Powercor, *Regulatory proposal*, p. 16.

38 Jemena, *Regulatory proposal*, p. 46.

39 SP AusNet, *Regulatory proposal*, p. 28.

United Energy stated in its regulatory proposal:

> new connection and augmentation assets are simply assets that form a part of the distribution system that is used to provide standard control services. New connection and augmentation works are not a separate service capable of classification. However, if they were such services, they would be properly characterised as standard control services as they are services going to the construction of the distribution network.[40]

United Energy also submitted that classification as a negotiated service is not consistent with the current regulatory approach. United Energy stated that, under the current ESCV approach, the purpose of customer contributions is to ensure that customers expect to pay at least the net incremental cost of providing their service by reference to:

- the present value of the expected stream of distribution tariffs over the expected life of the customer’s connection
- the incremental cost of providing network services to that customer, including the impact of that customer’s connection on the timing of future augmentations to the network.[41]

One of the reasons behind the AER's Framework and approach paper classification of new connections requiring augmentation works as negotiated services was uncertainty regarding the future status of ESCV Guideline 14 in the forthcoming regulatory control period.[42]

Since the publication of the Framework and approach paper, the AER has received advice from the Victorian Department of Primary Industries (DPI)[43] of its intention that the capital contributions and contestability of works arrangements (relating to new connections requiring augmentation works) in Guideline 14 will continue to apply to the Victorian DNSPs in the forthcoming regulatory control period, and until regulatory arrangements in Victoria impacted by the National Energy Customer Framework are settled.

The AER notes that the National Energy Customer Framework, which is currently being developed, may come into effect in Victoria at some time during the 2011–15 regulatory control period. It is expected that this framework will contain provisions for new customer connections.

In classifying services (under clause 6.2.1 of the NER) that have previously been subject to regulation under the present or earlier legislation, unless a different classification is clearly more appropriate, the AER must act on the basis that there should be no departure from a previous classification, if the services have been previously classified under a previous regulatory regime.[44]

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40 United Energy, *Regulatory proposal*, p. 175.
41 United Energy, *Regulatory proposal*, p. 176.
42 AER, *Framework and approach Paper*, May 2009, pp. 34–39.
43 Meeting between AER and DPI staff on 16 October 2009.
44 NER, cl.6.2.1 (d)(1)

The AER considers that there are good reasons to depart from its classification in the Framework and approach paper in light of submissions received from the DNSPs in relation to the appropriate classification of new connections requiring augmentation works, and after further reflecting on the operation of existing Victorian requirements and advice from DPI.[45] That is, the AER will classify new connections requiring connection and augmentation works as standard control services in the forthcoming regulatory control period, to be regulated in accordance with the weighted average price cap (WAPC) form of control as indicated in chapter 4 of this draft decision. Capital contribution arrangements for these services will continue to be regulated under ESCV Guideline 14, consistent with DPI's advice to the AER.

The AER understands that new connections requiring augmentation works have, in the current regulatory control period, been classified as prescribed distribution services by the ESCV, consistent with the Victorian Electricity Industry Tariff Order 1995.[46] The AER is aware that any capital contributions associated with the new connections requiring augmentation works were classified as excluded services under the 2005 Tariff Order.[47] These capital contributions have been regulated under ESCV Guideline 14 and will continue to be regulated under this instrument in the forthcoming regulatory control period.

In accordance with DPI's advice, the regulation of capital contributions under Guideline 14 will be maintained and the current arrangements as previously administered by the ESCV, now administered by the AER. The AER wishes to minimise any potential overlap or conflict between the NER framework and the capital contribution provisions of Guideline 14. Were the AER to maintain its Framework and approach paper classification of these services as negotiated services, the capital contribution component would be necessarily regulated through Part D of chapter 6 of the NER. This would mean access to the service would be determined by the relevant DNSPs' negotiating framework, the AER's NDSC, and the NER regulatory framework. Price and other terms and conditions would need to be negotiated between the DNSP and the service applicant. Guideline 14 would only operate to the extent that it is not inconsistent with these provisions.

The amount of upfront financial contributions for new connections requiring augmentation works will be regulated and calculated in accordance with the relevant provisions of ESCV Guideline 14 (or its successor instrument) consistent with DPI's advice to the AER. The AER is mindful of the capital contributions provisions in the clause 6.21.2 of the NER, which provide that in relation to capital contributions:

> 1. the DNSP is not entitled to recover, under a mechanism for the economic regulation of direct control services, any component representing asset related costs for assets provided by Distribution Network Users; and
>
> 2. the DNSP may receive a capital contribution, prepayment and/or financial guarantee up to the provider's future revenue related to the provision of direct control services for any new assets installed as part of a new connection or modification to an existing connection, including any augmentation to the distribution network; and

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45 NER, cl.6.12.3 (b)
46 ESCV, *Victorian Electricity Supply Industry Tariff Order 1995*, p. 28.
47 ESCV, *Victorian Electricity Supply Industry Tariff Order 2005*, s. 5.7.3(h)

> 3. where assets have been the subject of a contribution or prepayment, the DNSP must amend the provider's revenue related to the provision of direct control services.

The AER considers that the provisions in the NER do not conflict with the provisions relating to capital contributions in Guideline 14, and that the two sets of provisions can operate concurrently.

The AER therefore intends to classify new connections requiring connection and augmentation works as standard control services for the 2011–15 regulatory control period, with capital contributions regulated under ESCV Guideline 14 and the relevant provisions of the NER.

2.6.2 Standard connections/routine connections

These are new connections of a routine or standard nature, where significant new works are not required to facilitate a customer's connection to the distribution network. ESCV Guideline 14 distinguishes these connection services from new connections requiring connection and augmentation works, with only the latter service subject to the contestability of works and capital contribution arrangements under that guideline.

SP AusNet stated that it intended to classify and treat all standard connection services as alternative control services based on a fixed fee approach for customers up to 100 amps and as a quoted alternative control service for customers above 100 amps. The intended effect of SP AusNet's proposed approach is to continue the current Victorian arrangements.[48] Jemena proposed to classify routine connections as standard control services,[49] and provided a list of charges associated with the provision of these services.[50]

Even though United Energy did not expressly state in its regulatory proposal that it wished to depart from the AER's Framework and approach paper position, it did list several standard connection services as 'standard control services' in the Alternative Control Appendix to its regulatory proposal.[51]

The AER considers that the 'standard' and 'routine' connection services outlined by SP AusNet and Jemena respectively are analogous in nature. The AER intends to treat them in the same manner and refers to these services here as 'routine connections'.

The AER agrees with SP AusNet that the previous classification of routine connections under the ESCV regime as excluded services is analogous to their classification as alternative control services under the NER (with services to customers below 100 amps being treated as fee based services, and services to customers above 100 amps being treated as quoted services).[52]

48 SP AusNet, *Regulatory proposal*, p. 31.
49 Jemena, *Regulatory proposal*, p. 45.
50 ibid., p. 48.
51 United Energy, *Regulatory proposal - Alternative Control Services Appendix*, p. 7.
52 ESCV, *Electricity Distribution Price Review 2006–2010, final decision* October 2005, pp. 161–173. See also SP AusNet, *Regulatory proposal*, p. 32.

In response to Jemena's proposed treatment of routine connections as standard control services, the AER considers that, given that Jemena can identify costs associated with the provision of the service, and can attribute those costs to individual customers who receive those services, the service is more appropriately treated as an alternative control service.

In light of the information provided by the Victorian DNSPs in their regulatory proposals, and for the reasons listed above, the AER confirms its approach and classifies routine connections as alternative control services, with a distinction being made as follows:

- treatment as fee based services for customer connections below 100 amps
- treatment as quoted services for customer connections above 100 amps.

2.6.3 Auditing design and construction and specification and design enquiry

CitiPower and Powercor submitted that auditing design and construction services and specification and design enquiry services should be classified as standard control services. CitiPower and Powercor submitted that these services are inextricably linked to the establishment of new or modified customer connections and to the payment of customer contributions.[53] CitiPower and Powercor argued that there is no scope for competition in the market for the provision of specification and design enquiry services.[54]

While the potential for development of competition in a market is one of the factors that the AER must consider when classifying a direct control service as either a standard control service or an alternative control service, it must also have regard to the extent that the costs of providing the relevant service are directly attributable to the customer to whom the service is provided.[55] The AER considers that costs incurred in the provision of these services can be directly attributed to a specific customer or group of customers. Further, the services were previously treated as excluded services under the ESC regulatory framework, which is a primary consideration in classifying direct control services under clause 6.2.2 (d) of the NER.

Therefore, the AER does not consider that there are good reasons to depart from its service classification in the Framework and approach paper. Auditing design and construction will be classified as an alternative control service for the forthcoming regulatory control period (and further grouped into the quoted service group of alternative control services). Specification and design enquiry will be classified as an alternative control service for the forthcoming regulatory control period (and further grouped into the quoted service group of alternative control services).[56]

[53] CitiPower, *Regulatory proposal*, p. 19; Powercor, *Regulatory proposal*, pp. 19–20.
[54] ibid.
[55] NER, cl. 6.2.2 (c)(5).
[56] Noting NER, cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

2.6.4 Temporary supply services

CitiPower and Powercor submitted that these services should be classified as standard control services, stating that where connection is required on a temporary basis, a new connection fee is charged. Further, CitiPower and Powercor stated that the same business effort is required for temporary connections as for new connections.[57]

The AER notes that temporary supply services have been classified under the ESCV framework as excluded services, which the AER considers are analogous to alternative control services under the NER. The AER considers that costs incurred through the provision of these services can be directly attributed to a specific customer or group of customers.

The AER considers that there are not good reasons to depart from the Framework and approach paper classification of temporary supply services. The AER will classify temporary supply services as alternative control services for the forthcoming regulatory control period (and further group it into the quoted service group of alternative control services).[58]

2.6.5 Location of underground cables

CitiPower and Powercor submitted that these services should be standard control services.[59] Both parties stated:

> The classification of the 'location of underground cables' service as a Standard Control Service will promote the long term interests of consumers of electricity with respect to the safety and reliability of supply, and system reliability.…. This classification will promote the safety not just of the person seeking the location of the underground cable, but the community in general. Since the commencement of the current regulatory control period, CitiPower has not charged a fee to persons seeking the location of underground cables. The decision to cease charging a fee followed a number of incidents where persons did not contact CitiPower prior to excavating in order to avoid paying a fee. This resulted in instances of cables being severed, which compromised the safety of those undertaking the excavations and the community as well as affecting system reliability. [60]

This service is commonly known as a 'dial before you dig' service and is used by contractors to locate underground cables, prior to excavation, by phoning a '13' telephone service.

The AER considers that the nature of this service means that it can be provided at a relatively low cost and notes that no excluded service charge has applied to this service in the current regulatory control period. The cost of this service has therefore been recovered through prescribed (that is, network) services. The AER considers that the cost of regulating this service separately as an alternative control service would outweigh the benefits of regulating the service in this manner.

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57 CitiPower, *Regulatory proposal*, p. 19; Powercor, *Regulatory proposal*, p. 19.

58 Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

59 CitiPower, *Regulatory proposal*, p. 20; Powercor, *Regulatory proposal*, pp. 21–22.

60 CitiPower, *Regulatory proposal*, p. 20; Powercor, *Regulatory proposal*, p. 21.

For these reasons, the AER considers it appropriate to depart from its framework and approach classification and will classify location of underground cables as a standard control service for the 2011–15 regulatory control period.

2.6.6 Covering of low voltage mains for safety purposes

CitiPower and Powercor submitted that this service should be classified as a standard control service.[61] CitiPower and Powercor stated that such services have been classified as prescribed services under the current ESCV framework.[62]

Both DNSPs noted that such a classification will promote the broad interests and safety of the community in general. CitiPower and Powercor stated that they no longer charge a fee for this service following a number of incidents where persons did not contact the DNSP prior to operating large equipment in the vicinity of low voltage mains in order to avoid paying a fee, and subsequently damaged lines.[63] However, CitiPower and Powercor did not provide any evidence or supporting information to this argument. Further, these are not relevant considerations for classification of distribution services under the NER.

SP AusNet proposed that this service should be classified as a quoted alternative control service rather than as a fee based alternative control service.[64] SP AusNet considered this to be consistent with the current ESCV framework, stating that

> charges for covering of low voltage mains for safety reasons are set out in the SP AusNet Excluded Services Section of the 2006–10 Electricity Distribution Price Review (2006 EDPR) Final Decision Volume 2 Price Determination. The 2006 EDPR Determination requires that these works are billed at recoverable works rates (equivalent to a quoted service).[65]

The AER is of the view that this service has been treated as an excluded service under the ESCV framework, and notes that CitiPower and Powercor have not provided any evidence supporting its treatment as a prescribed service.

The AER considers that the costs incurred through the provision of covering of low voltage mains for safety purposes can be directly attributed to a customer or group of customers. The AER notes that due to the variable nature of costs associated with this service, it is more appropriately treated as a quoted service, rather than a fee based service.

Therefore, the AER considers that there are good reasons to depart from its fee based alternative control service classification in the Framework and approach paper. The AER will classify coverage of low voltage mains as alternative control services for the

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61 CitiPower, *Regulatory proposal*, p. 19; Powercor, *Regulatory proposal*, p. 22.
62 ibid.
63 CitiPower, *Regulatory proposal*, p. 22; Powercor, *Regulatory proposal*, p. 22.
64 SP AusNet, *Regulatory proposal*, p. 33.
65 SP AusNet, *Regulatory proposal*, p. 33, quoting *ESCV, EDPR 2006–10 Vol.2, October 2006*, pp. 162–173.

2011–15 regulatory control period and further group it into the quoted service group of alternative control services.[66]

2.6.7 Elective undergrounding where an above ground service currently exists

CitiPower and Powercor submitted this service should be classified as a standard control service.[67] In responding to the AER's Framework and approach paper classification, both DNSPs stated:

- the cost of evaluating site conditions and providing the service cannot be estimated without first understanding the customer's individual needs. The DNSPs' experience is that the costs of excavation or boring varies substantially depending on the type of soil.
- an individual price must be set for the service after it has been requested in accordance with Guideline 14.[68]

SP AusNet proposed that this service be classified as an alternative control service (quoted) and not an alternative control service (fee based).[69] It stated:

> this work is a result of a specific and easily attributable request from a customer, it is important that charges are cost reflective. Given the diversity in undergrounding requests, a quoted service is much preferred to a fee based charge. In particular, a fee based charge must necessarily reflect a degree of averaging, and the resulting charges will only be fully cost reflective in a relatively small number of cases. In contrast, quoted charges can consider the particular circumstances of each undergrounding request.[70]

The AER concurs with SP AusNet's view that the service should be classified as an alternative control service (quoted service), due to the variable nature of costs potentially incurred in the provision of this service.

The AER does not agree with CitiPower and Powercor's submissions that the service should be treated as a standard control service. The service can be directly attributed to a particular class of customers, and the relevant costs should be recovered from those customers. The AER notes that these services have been treated as excluded services under the ESCV framework.

Therefore, the AER considers that there are good reasons to depart from its service classification of elective undergrounding in the Framework and approach paper. The AER will classify coverage of elective undergrounding where an above ground

[66] Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.
[67] CitiPower, *Regulatory proposal*, pp. 27–28; Powercor, *Regulatory proposal*, p. 28.
[68] ibid.
[69] SP AusNet, *Regulatory proposal*, p. 32.
[70] ibid.

service exists as alternative control service for the 2011–15 regulatory control period (and further classify it into the quoted services group of alternative control services).[71]

2.6.8 Fault level compliance service

CitiPower proposed that this service refers to maintaining network security to allow for the connection of additional embedded generation. It involves the provision of infrastructure to mitigate network fault levels arising from connection of embedded generation.[72] CitiPower has been advised by the Property Council of Australia (PCA) that a number of embedded generators are planned to be installed within the central Melbourne/Docklands area in the forthcoming regulatory control period.

CitiPower stated that it has included proposed expenditure associated with this new service in its capex forecasts. CitiPower stated that:

> CitiPower proposes that its costs be recovered from embedded generators seeking parallel connection to the network with name plate ratings above 100kW through a per kW charge. CitiPower notes that it is not seeking to impose charges in relation to the conveyance or transfer of electricity to embedded generators but rather to apply charges in respect of compliance with applicable network standards following connection.[73]

CitiPower has provided further information to the AER advising that a one-off charge of $625 per kW would apply to this service and that the charge would only apply to generators with a name plate rating in excess of 100kW.[74]

It is clear to the AER that CitiPower's proposed fault level compliance service should be a direct control service. However, the service must be further classified as either a standard control service or an alternative control service.

The AER notes that the *ESCV Electricity Industry Guideline 15* (Guideline 15) deals explicitly with the connection of embedded generators, and the treatment of costs associated with these services.

In Guideline 15, the ESCV identifies several services relating to the connection of embedded generators to the distribution network, including:

> the charges under, and other terms and conditions of, connection agreements, including principles distributors must observe in setting those charges and other terms and conditions.[75]

The AER considers that CitiPower's fault level compliance service falls within the scope of this definition.

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[71] Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.
[72] Email from CitiPower to the AER on 23 February 2010.
[73] CitiPower, *Regulatory proposal*, p. 28.
[74] Email from CitiPower to the AER on 23 February 2010.
[75] ESCV, *Electricity Industry Guideline No. 15, Connection of Embedded Generation*, cl. 1.1.1 (b).

The AER further notes that ESCV Guideline 15 provides that services related to the connection of embedded generators are classified as non contestable excluded services.[76]

It would appear from this previous classification that fault level compliance services are most appropriately classified as alternative control services under the NER for the 2011–15 regulatory control period.

Further, in having regard to clause 6.2.2(c)(5) of the NER, the AER notes that CitiPower has stated:

> The fault level compliance charge will be recovered via a per kW charge for each new embedded generator based on their unit name plate ratings. Thus the party that creates the fault level issue will be the party that pays for its correction.[77]

The AER considers that the cost associated with fault level compliance checks can be attributed to an individual customer or network user. Although CitiPower has proposed this service as a standard control service, it has also identified a charge associated with the service, and has noted that the charge can be attributed to the party that creates the fault level issue (that is, the embedded generator).

Because of the nature of the service, and its previous regulatory treatment, the AER will classify the service as an alternative control service (and further classify it into the fee based group of alternative control services) for the 2011–15 regulatory control period. The AER further notes that CitiPower, in submitting its revised regulatory proposal, will need to provide a cost break down of the fee associated with the fault level compliance service.

2.6.9 Reserve feeder

CitiPower and Powercor noted that the AER's Framework and approach paper did not classify the reserve feeder service. They considered that this service should be classified as a negotiated service, as the service relates to customers who are receiving a service above and beyond the minimum standards, and that costs of providing the service are directly attributable to the customer who is receiving the service.[78]

In preliminary consultation with the Victorian DNSPs on the framework and approach process in 2008, the AER sought information from each of the Victorian DNSPs on the services that they are providing in the current regulatory control period. During this process, CitiPower and Powercor did inform the AER of its reserve feeder service, which the AER subsequently did not classify in its Framework and approach paper due to an oversight. [79] The ESCV previously classified this service as an excluded service.

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76 ESCV, *Guideline 15*., cl. 3.1.3

77 Email from CitiPower to the AER staff on 23 February 2010.

78 CitiPower, *Regulatory proposal*, p. 22; Powercor, *Regulatory proposal*, p. 23.

79 CitiPower/Powercor, *Victorian Framework and approach - DNSP information request: service classification and control mechanisms*, 12 October 2008, p. 44.

Upon review, the AER notes that in their response to subsequent AER enquiries, CitiPower and Powercor have advised the AER that they currently levy a per kilowatt charge of $12.54 for this service.

The AER considered the nature of the service and its classification as an excluded service under the ESCV framework. The AER also notes that the costs associated with the service can be identified and attributed to a specific customer (further noting that these costs can be ascertained in advance, with no negotiation required between the DNSP and customer). For these reasons, the AER will classify the service as an alternative control service for the 2011–15 regulatory control period (and further classify it into the fee based group of alternative control services).[80]

2.6.10 Provision of watchman lights and repair of watchman lights

CitiPower and Powercor proposed that the provision of watchman (security) lights and the repair of watchman lights both be classified as negotiated services. CitiPower and Powercor state that this is appropriate as these services relate to customers who are receiving a service above and beyond the minimum standard of service, and that the cost of providing these services is directly attributable to the customer who is receiving them. Further, the DNSPs stated that customers are able to seek the provision and repair of watchman lights from parties other than a DNSP.[81]

The AER did consider the classification of these services in its Framework and approach paper, and decided that they did not require classification. This was consistent with the current treatment of these services in Victoria where they are not subject to economic regulation.[82] The AER does not consider it appropriate to depart from the classification in the Framework and approach paper as these services are able to be provided by parties other than the DNSP.

The AER will treat these services as unclassified for the 2011–15 regulatory control period.

2.6.11 Meter investigation and special readings

CitiPower and Powercor stated that the AER overlooked metering investigation services (including special readings) in the Framework and approach paper, and that these services are not classified as part of the Advanced Metering Infrastructure (AMI) determination.[83]

Metering investigation services and special readings are undertaken for connection points where requested by a retailer. These services provide for meter investigation and readings outside of scheduled meter reading services. CitiPower and Powercor suggested that this service should be regulated by the AER under its Distribution Determination as an alternative control service (fee based).[84]

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80 Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

81 CitiPower, *Regulatory proposal*, p. 23; Powercor, *Regulatory proposal*, p. 23.

82 AER, *Framework and approach*, p. 134.

83 CitiPower, *Regulatory proposal*, p. 25; Powercor, *Regulatory proposal*, pp. 24–25.

84 ibid.

In preliminary consultation with the Victorian DNSPs on the Framework and approach process in 2008, the AER sought information from each of the Victorian DNSPs on the services that they are providing in the current regulatory control period. During this process, CitiPower and Powercor informed the AER that they currently provide meter investigation services.[85]

The AER notes that this service was treated as an excluded service under the ESCV framework. The AER, in maintaining consistency with the previous regulatory approach, will classify the service as an alternative control service for the 2011–15 regulatory control period (and further classify it into the fee based group of alternative control services).[86]

AMI metering services

A number of changes to alternative control services will occur due to the rollout of AMI across Victoria over the forthcoming regulatory control period. As a result of the AMI rollout, some services will become redundant, others will reduce in price due to the service being provided remotely instead of manually, and some new services related to AMI meters will emerge. The regulatory arrangements relating to the AMI rollout are set out in an August 2007 Order in Council made by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000. An amending Order in Council was made on 25 November 2008 (the 'revised Order'). Clause 3 of the revised Order requires that metering services (which the AER considers includes new remote services, such as remote energisation or remote special reads) are to be regulated as 'excluded services.' In the current regulatory control period, excluded services were regulated under the DNSPs' distribution licences and Guideline 14.

Accordingly, the AER will regulate the new services that are facilitated by AMI (including all remote services) under the DNSPs' distribution licences and Guideline 14.[87] The AER expects that such prices for remote metering services, which when the AMI rollout is completed will largely replace similar manual services, will be a fraction of the price of equivalent manual services, due to the minimal labour required to perform a remote service through an AMI meter.

2.6.12 PV installation

CitiPower and Powercor submitted that the AER's Framework and approach paper did not classify PV installation and submitted that this service should be classified as an alternative control service (fee based).[88] The PV installation service does not include the installation of PV units, but rather covers the site inspection for distribution network users who have installed PV units. This service also involves the testing of

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85 CitiPower/Powercor, *Victorian Framework and approach - DNSP information request: service classification and control mechanisms*, 12 October 2008, p. 44.

86 Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

87 The AER notes that Jemena proposed charges for certain remote services as part of its regulatory proposal, and indicated to the AER that it would be in a position to provide these remote services to customers with AMI meters in May 2010. The AER will regulate these remote services in accordance with the DNSPs' distribution licences and Guideline 14.

88 CitiPower, *Regulatory proposal*, p. 27; Powercor, *Regulatory proposal*, p. 27.

the inverter and related equipment to ensure that these mechanisms are operating correctly.

Both DNSPs stated that this service should be classified as an alternative control service (fee based), for the reasons listed below:

- for electrical safety reasons the DNSP is the only party that can provide this service
- the nature and scope of the works can be known with reasonable certainty in advance
- the cost of providing the service can be estimated with reasonable certainty in advance
- a generic schedule of prices can be set for the service before the service is requested
- the service, and therefore the cost, can be attributed directly to an individual customer.[89]

The AER did not classify this service in its Framework and approach paper. The AER concurs with CitiPower's and Powercor's reasons for proposing that the service be treated as an alternative control service (fee based). For these reasons, the AER will classify the service as an alternative control service for the 2011–15 regulatory control period (and further classify it into the fee based group of alternative control services).[90]

2.6.13 Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh

CitiPower and Powercor submitted that this service should not be regulated, stating that the service relates to large customers that can have type 1 to 4 meters installed by any metering provider. CitiPower and Powercor considered that a competitive market therefore exists in relation to the provision of meters to these customers and regulation is not required.[91]

The AER does not concur with this view. This classification would be inconsistent with the current regulatory treatment of the service as an excluded service. Although CitiPower and Powercor both submit that a competitive market exists for the provision of meters that are substitutes for type 5 and type 6 meters, the AER understands that, for existing type 5 and type 6 meters, a DNSP is the only party that can undertake re-tests of its installed meters.

Therefore, the AER considers that it has no grounds to depart from its Framework and approach paper classification. The costs associated with this service can be attributed

[89] CitiPower, *Regulatory proposal*, p. 27; Powercor, *Regulatory proposal*, p. 27.

[90] Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

[91] CitiPower, *Regulatory proposal*, p. 29; Powercor, *Regulatory proposal*, pp. 28–29.

to an individual customer. The AER will classify re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh as alternative control services for the 2011–15 regulatory control period (and further classify these into the fee based group of alternative control services).[92]

2.6.14 Energisation of new connections

In response to the Framework and approach paper's classification of new connections as alternative control services, CitiPower and Powercor proposed that no discrete classification for the energisation of new connections is required. CitiPower and Powercor considered the service of energising a new connection to be indistinguishable from that of the de-energisation or re-energisation of existing connections. CitiPower and Powercor further stated that, should the AER classify energisation of new connections as a separate service, then the appropriate classification is as an alternative control service (fee based).[93]

The AER considers that this is a further clarification of its position in the Framework and approach paper (its position in the Framework and approach paper was to classify these services as alternative control services). The AER concurs with CitiPower and Powercor and will classify energisation, de-energisation and re-energisation services together as alternative control services for the 2011–15 regulatory control period (and further classify it into the fee based group of alternative control services).[94]

2.6.15 Repair of overhead service cables damaged by high load vehicles

These services are for reinstatement of overhead service cables damaged by high load escorts. In justifying their proposal to classify these services as quoted alternative control services, CitiPower and Powercor noted:

- the nature and scope of the works differs between events
- the cost of providing the service cannot be estimated without first understanding the scope and nature of the works
- an individual price must be set for the service after the event.[95]

In justifying its position, SP AusNet noted that it services a diverse urban, rural and remote service territory, which leads to different costs for this service relating to:

- travel time and vehicle costs
- pole to pit distances due to varying block sizes
- differing network design parameters.[96]

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92 Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

93 CitiPower, *Regulatory proposal*, p. 20; Powercor, *Regulatory proposal*, pp. 21–22.

94 Noting NER, cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

95 CitiPower, *Regulatory proposal*, pp. 29-30; Powercor, *Regulatory proposal*, p. 29.

The AER concurs with these positions. Due to the variable nature of the costs associated with the provision of such services, the AER will classify repair of damage to overhead service cables caused by high load vehicles as an alternative control service for the 2011–15 regulatory control period (and further classify it into the quoted group of alternative control services).[97]

2.6.16 High load escorts—lifting overhead lines

CitiPower and Powercor proposed that high load escorts (lifting overhead lines) be classified as a quoted alternative control service rather than as a fee based alternative control service as proposed in the AER's Framework and approach paper.[98]

The AER concurs with these positions. Due to the variable nature of costs associated with the provision of such services, the AER will classify high load escorts—lifting overhead lines as an alternative control service for the 2011–15 regulatory control period (and further classify it into the quoted group of alternative control services).[99]

2.6.17 New public lighting assets

The AER notes that a Memorandum of Understanding (MOU) has been entered into between:

- Victorian DNSPs
- VicRoads
- Victorian Local Government Association
- Municipal Association of Victoria
- Victorian Department of Sustainability and Environment.[100]

This MOU relates to public lighting, and specifically sets out procedures for introducing new lighting technologies at any time in Victoria to meet environmental (and other) objectives.

The AER notes that its Framework and approach paper classified the alteration and relocation of existing DNSP public lighting assets, and the provision of new public lighting assets, as negotiated services (noting the regulatory arrangements under the ESCV's Public Lighting Code and Guideline 14 and that under these arrangements public lighting services can be provided by parties other than the DNSP, such as VicRoads and local councils).

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96 SP AusNet, *Regulatory proposal*, pp. 32 and.35.

97 Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

98 CitiPower, *Regulatory proposal*, p. 30; Powercor, *Regulatory proposal*, p. 29.

99 Noting NER cl.6.2.2 (b), which allows the AER to group direct control services together for the purposes of classification.

100 Entered into September 2009.

The AER considers that 'new public lighting assets' in the context of the Framework and approach paper applies to assets constructed in new residential and commercial subdivisions by parties other than the DNSP. Under Victorian arrangements, these assets are vested to the DNSP upon connection to the relevant electricity distribution network. The DNSP is then responsible for the associated operation, maintenance, repair and replacement of these assets under the Public Lighting Code (the Code).

New technology public lighting assets that are constructed from the commencement of the 2011–15 regulatory control period are considered by the AER to be new assets and subject to the AER's negotiating criteria and the relevant DNSPs' negotiating framework. Accordingly, councils and DNSPs can negotiate a charge for a new lighting technology that is not regulated as an alternative control service under the AER's final distribution determination.

The AER notes that it is not empowered under the NER to consider or request ad hoc proposals for public lighting charges where a distribution determination is already in place. The introduction of any new lighting technology during 2011–15 will therefore be on a negotiated basis. Disputes arising from the provision of such services will be dealt with under the relevant dispute resolution processes, contained in Part L of the NER.

The AER considers that such arrangements do not present conflict with the continuation of negotiations between local councils and service providers under the MOU for new lighting technology to be introduced during 2011–15 (but not included by the Victorian DNSPs in their regulatory proposals for the 2011–15 regulatory control period).

2.6.18 Unmetered supplies for Type 7 meters and remote metering services

The AER, in its Framework and approach paper, classified unmetered supplies for Type 7 meters as alternative control services (as this was an excluded service under the ESCV's framework).[101] The AER notes, that, even though these were excluded services in the current regulatory control period, they will be regulated by the AMI Order in Council (clause 6) for future regulatory control periods.

A noted above in section 2.6.11, remote services are to be regulated as excluded services. As such, the AER has not classified these remote metering services for the forthcoming regulatory control period, and has not considered remote metering services as part of this draft decision.

2.7 Submissions on DNSP regulatory proposals

As outlined in section 2.1.5, the AER received two submissions in relation to service classification, from Origin Energy and Central Victorian Greenhouse Alliance (CVGA). In its submission, Origin Energy expressed concerns about new connections, routine connections, and the possible interaction between Guideline 14 and the NER. CVGA expressed concerns about the classification of new connections requiring augmentation works as negotiated services.

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101 AER, *Framework and approach paper*, May 2009, p. 132.

New Connections

Origin Energy raised a concern that classification of new connections as standard control services may be inappropriate under the NER. The AER notes that such a classification is not in conflict with the NER because a regulated rate of return is earned on capital expenditure incurred through the provision of standard control services through the regulatory asset base (RAB). This (along with opex) is recovered through service and usage charges in accordance with the relevant tariff. Any customer contribution associated with a new connection (that is, in a situation where the incremental cost of a new connection is not met by incremental revenue recovered through tariffs) is excluded from the RAB (through the operation of clause 6.21.2 of the NER) so that the DNSP will not earn a return over time (through the RAB) on that portion of the connection that is contributed upfront by a customer.

CVGA also noted concern with the treatment of new connections requiring augmentation works as negotiated services, and stated that these services would be more appropriately treated as direct control services. The AER notes that the Framework and approach paper service classification has been amended, and that these services are now being classified as direct control services (standard control services).

Public lighting—contestability

In determining whether “new public lighting assets” are contestable, the AER has considered clause 1.3 of the Code, which states that the Code only applies to public lighting assets owned by the DNSPs. The AER notes that clause 4.4 of the Code mandates processes where alterations are to be made to existing assets. Specifically, a customer must, among other matters, obtain the DNSP’s approval of the person who undertakes this work. For further discussion of this issue, see chapter 19 of this draft decision.

2.8 AER conclusion

In accordance with clause 6.12.1 (1) of the NER, the AER's decision on service classification is set out below, and at appendix B of this draft decision. The AER does not accept all aspects of the Victorian DNSPs' regulatory proposals on the classification of distribution services. The AER's response to each proposed service classification amendment for each Victorian DNSP is as follows:

Jemena

- the AER rejects Jemena's classification of routine connection as standard control services

- the AER accepts Jemena's classification of new connections requiring augmentation works as standard control services.

SP AusNet

- the AER accepts SP AusNet's classification of new connections requiring augmentation works as standard control services

- the AER accepts SP AusNet's classification of routine connections as alternative control services (fee based services for customers below 100 amps, and quoted services for customers above 100 amps)

- the AER accepts SP AusNet's classification of covering of low voltage mains as an alternative control service (quoted service)

- the AER accepts SP AusNet's classification of elective undergrounding where an above ground services exists as an alternative control service (quoted service)

- the AER accepts SP AusNet's classification of repair damage to overhead service cables caused by high load vehicles as alternative control services (quoted services)

- the AER accepts SP AusNet's classification of high load escorts—lifting overhead lines as alternative control services (quoted services).

CitiPower/Powercor

- the AER accepts CitiPower/Powercor's classification of new connection and augmentation works as standard control services

- the AER rejects CitiPower/Powercor 's classification of auditing design and construction as standard control services and instead classifies them as alternative control services

- the AER rejects CitiPower/Powercor 's classification of specification and design enquiry as standard control services and instead classifies them as alternative control services

- the AER rejects CitiPower/Powercor 's classification of temporary supply services standard control services and instead classifies them as alternative control services

- the AER accepts CitiPower/Powercor 's classification of location of underground cables as a standard control service

- the AER rejects CitiPower/Powercor 's classification of covering of low voltage mains for safety as a standard control service and instead classifies them as alternative control services (quoted)

- the AER rejects CitiPower/Powercor 's classification of elective undergrounding where aboveground service exists as a standard control service and instead classifies them as alternative control services (quoted0

- the AER rejects CitiPower/Powercor 's classification of fault level compliance services as standard control services, and instead classifies them as alternative control services (fee based)

- the AER rejects CitiPower/Powercor 's classification of reserve feeder services as negotiated services, and instead classifies them as alternative control services (fee based)

- the AER rejects CitiPower/Powercor 's classification of provision of watchman lights as negotiated services, and instead treats them as unclassified
- the AER rejects CitiPower/Powercor's classification of repair of watchman lights as negotiated services, and instead classifies them as unclassified
- the AER accepts CitiPower/Powercor 's classification of meter investigation as an alternative control service (fee based)
- the AER accepts CitiPower/Powercor 's classification of special reading as an alternative control service (fee based)
- the AER accepts CitiPower/Powercor 's classification of PV installation as an alternative control service (fee based)
- the AER rejects CitiPower/Powercor 's classification of re-test of types 5 and 6 metering installations as an unclassified service, and classifies them as alternative control services
- the AER accepts CitiPower/Powercor 's classification of energisation of new connections as alternative control services (fee based)
- the AER accepts CitiPower/Powercor 's classification of repair to damage to overhead service cables as alternative control services (quoted services)
- the AER accepts CitiPower/Powercor 's classification of classify high load escorts as alternative control services (quoted services)

United Energy

- the AER accepts United Energy's classification of new connections requiring augmentation works as standard control services.

These positions are also outlined in the AER's determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy, and are also summarised in appendix B.

3 Arrangements for negotiation

3.1 Introduction

A distribution determination imposes price controls and revenue controls, which are recovered through the distribution network service provider (DNSP) provisions for direct control services. However, services which are classified by the AER as negotiated distribution services do not have their terms and conditions, or their prices, set by the AER through a distribution determination. Rather, these services are subject to negotiation, arbitration and dispute resolution, which are facilitated through a negotiating framework (proposed by DNSPs and adhered to throughout the negotiating process) and negotiating distribution service criteria (NDSC).

NDSC

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

This chapter reviews issues raised in submissions regarding the NDSC, and sets out the AER’s consideration of and conclusions on the NDSC to apply to the Victorian DNSPs in the forthcoming regulatory control period.

Negotiating framework

While the NDSC provide the high level criteria for negotiation, the negotiating framework sets out the procedures to be followed by a DNSP when negotiating with a third party for the provision of negotiated services. As part of their regulatory proposals, CitiPower, Powercor, Jemena, SP AusNet and United Energy each provided a proposed negotiating framework, which the AER must assess and approve (or amend) in accordance with clause 6.12.1(15) of the National Electricity Rules (NER).

Each Victorian DNSP has several services classified as negotiated distribution services. Therefore, each DNSP has submitted a negotiating framework in accordance with clause 6.8.2(c)(5) of the NER. The AER has assessed each negotiating framework, details of this assessment are in section 3.5 below.

This chapter reviews issues raised in submissions regarding the negotiating frameworks submitted by the Victorian DNSPs. This chapter also provides the AER's consideration and assessment of each DNSP's negotiating framework under the relevant NER provisions.

3.2 Regulatory requirements

3.2.1 NDSC

The NDSC sets 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.[1]

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

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

iv. any access charges that are to be paid to or by the provider.

On 23 December 2009, the AER published its proposed NDSC to apply to each Victorian DNSP. The AER's proposed NDSC gives effect to and is consistent with the negotiated distribution service principles set out in clause 6.7.1 of the NER.[2]

A decision on the NDSC to apply to the Victorian DNSPs' negotiated distribution services is a constituent decision of the AER's distribution determination, under clause 6.12.1(16) of the NER.

3.2.2 Negotiating framework

Under clause 6.8.2(c)(5) of the NER, each Victorian DNSP must submit a negotiating framework as part of its regulatory proposal for the forthcoming regulatory control period. A negotiating framework must set out the procedures to be followed during negotiations between a DNSP and any person wishing to receive a negotiated distribution service from the DNSP.[3]

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 require:

- the service applicant and service provider to negotiate in good faith the terms and conditions of access, and to provide each other with all such commercial information as reasonably required to engage in effective negotiation
- the provider:
  - to identify and inform the service applicant of the reasonable costs (and increase or decrease in costs) of providing the service; and to demonstrate that charges for the service are cost reflective
  - to have appropriate arrangements for assessment and review of the charges and the basis on which they are made

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1 NER, cl. 6.7.4(a).
2 NER, cl. 6.7.4(b).
3 NER, cl. 6.7.5 (a).

- the arrangements for provision of the service be commenced and finalised within specified periods (and a requirement that each party to the negotiations must make reasonable endeavours to adhere to these)

- a process for dispute resolution under the NER and National Electricity Law (NEL)

- the arrangements for payment of the provider's reasonable direct expenses incurred in processing the application to provide the negotiated distribution service

- the DNSP to determine the potential impact on other network users of the provision of the negotiated distribution service; and that the DNSP must notify and consult with any affected network users (ensuring that the provision of service does not result in non compliance with obligations to users under the NER)

- the DNSP to publish the results of negotiations on its website.

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.[4]

3.3 Summary of Victorian DNSP negotiating frameworks

3.3.1 Negotiated distribution service criteria

None of the Victorian DNSPs proposed any amendments to the AER's proposed NDSC in their regulatory proposals.

3.3.2 Negotiating framework

Each Victorian DNSP submitted its proposed negotiating framework for the forthcoming regulatory control period for assessment by the AER.

CitiPower

CitiPower's negotiating framework is structured as follows:[5]

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4 NER, cl. 6.7.3.
5 CitiPower, *Regulatory Proposal 2011 to 2015*, 30 November 2009, Attachment C0139.

- Section 1—application of negotiating framework
- Section 2—obligation to negotiate in good faith
- Section 3—provision of commercial information by CitiPower
- Section 4—provision of commercial information by service applicant
- Section 5—determination of impact on other distribution network users
- Section 6—timeframe for negotiations
- Section 7—suspension of timeframe for negotiations
- Section 8—publication of results of negotiation
- Section 9—dispute resolution
- Section 10—payment of CitiPower's reasonable direct expenses
- Section 11—termination of negotiations
- Section 12—GST
- Section 13—notices
- Section 14—miscellaneous.

Powercor

Powercor's negotiating framework is structured as follows:[6]

- Section 1—application of negotiating framework
- Section 2—obligation to negotiate in good faith
- Section 3—provision of commercial information by Powercor
- Section 4—provision of commercial information by service applicant
- Section 5—determination of impact on other distribution network users
- Section 6—timeframe for negotiations
- Section 7—suspension of timeframe for negotiations
- Section 8—publication of results of negotiation
- Section 9—dispute resolution
- Section 10—payment of Powercor's reasonable direct expenses

[6] Powercor, *Regulatory Proposal 2011 to 2015*, 30 November 2009, Attachment P0139.

- Section 11—termination of negotiations
- Section 12—GST
- Section 13—notices
- Section 14—miscellaneous.

Jemena

Jemena's negotiating framework is structured as follows:[7]

- Section 1—application of negotiated framework
- Section 2—timeframes
- Section 3—provision of commercial information by service applicant
- Section 4—provision of commercial information by Jemena
- Section 5—pricing principles
- Section 6—consultation with affected parties
- Section 7—payment of Jemena's costs
- Section 8—termination of negotiations
- Section 9—publication of results of negotiation
- Section 10—dispute resolution
- Section 11—giving notices
- Section 12—terms and abbreviations.

SP AusNet

SP AusNet's negotiating framework is structured as follows:[8]

- Section 1—application of negotiating framework
- Section 2—commencement of negotiations
- Section 3—application for negotiating distribution services
- Section 4—provision of information
- Section 5—determination of impact on other distribution users

7 Jemena, *Regulatory Proposal 2011-2015*, November 2009, Appendix 19.
8 SP AusNet, *Electricity Distribution Price Review, Regulatory proposal,* 30 November 2009, Appendix Q.

- Section 6—dispute resolution
- Section 7—notices
- Section 8—definitions and interpretations.

United Energy

United Energy's negotiating framework is structured as follows:[9]

- Section 1—preamble
- Section 2—application of a negotiating framework
- Section 3—commencement of negotiations
- Section 4—provision of commercial information by a service applicant
- Section 5—provision of commercial information by United Energy
- Section 6—process and timeframe for agreeing provision of negotiated distribution services
- Section 7—obligation to negotiate in good faith
- Section 8—determination of impact on other distribution network users and consultation with affected distribution network users
- Section 9—suspension of timeframe for provision of a negotiated distribution service
- Section 10—dispute resolution
- Section 11—payment of United Energy's reasonable costs
- Section 12—termination of negotiations
- Section 13—publication of results of negotiation on website
- Section 14—giving notices
- Section 15—miscellaneous.

3.4 Summary of submissions

The AER received no stakeholder submissions on the NDSC or any of the Victorian DNSPs' proposed negotiating frameworks.

9 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015,* November 2009, Appendix C-4.

3.5 Issues and AER considerations

3.5.1 Negotiated distribution service criteria

The Victorian DNSPs proposed no amendments to the NDSC. No submissions were received on the NDSC. The AER considers that no amendments should be made to the NDSC.

3.5.2 Negotiating frameworks

The AER has assessed each negotiating framework against the relevant provisions of clause 6.7.5(c) of the NER. The AER has identified several amendments required before it can approve the negotiating frameworks. The amendments are required to the negotiating frameworks submitted by Jemena, SP AusNet and United Energy.

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

SP AusNet, in its negotiating framework, states that 'SPI Electricity may provide commercial information to the applicant'.[10] In order to ensure consistency with clause 6.7.5.(c)(2) of the NER, the AER considers that this section should be amended. The AER considers that the provision should be amended to 'SPI Electricity will provide all commercial information that a service applicant would reasonably require to enable it to engage in effective negotiating with SPI Electricity'.

The addition of the word 'will' removes uncertainty as to SP AusNet's obligations to provide commercial information relevant to the negotiating process to the service applicant. This obligation to provide commercial information is a clear obligation created under clause 6.7.5(c)(2) of the NER.

Clause 6.7.5(c)(5) & 6.7.5(c)(9)—suspension of timeframes during consultation with affected parties

Jemena in paragraph 2.2.2 of its negotiating framework states that '[t]he timeframes for negotiation of the provision of a negotiated distribution service as set out in paragraph 2.1.3 or agreed pursuant to paragraph 2.1.4 may be extended if Jemena has been required to notify and consult with' affected distribution network users or Australian Energy Market Operator (AEMO) regarding the provision of negotiated distribution services.[11]

Jemena has informed the AER that suspension of timeframes is limited to the circumstances outlined in paragraphs 2.2.1A & B and that negotiations are not suspended during consultation with affected parties. Paragraph 2.2.2 allows for an extension of timeframes where, through no fault on Jemena's part, there is a delay in Jemena receiving information regarding potential impacts and costs.

The AER considers that the placement of paragraph 2.2.2 under section 2.2 Suspension of timeframes is not consistent with this new information. Further the AER considers that the apparent intention of paragraph 2.2.2 is captured by paragraph

10 SP AusNet, *Regulatory proposal,* Appendix Q, p. 6.
11 Jemena, *Regulatory proposal, Appendix 19:* p.3.

2.1.4 of Jemena's proposed negotiating framework. The AER therefore considers that paragraph 2.2.2 should be removed.

Clause 6.7.5(c)(7)—payment of expenses incurred in processing application

Paragraph 7.2.2 of Jemena's negotiating framework sets out the procedure to be followed by a service applicant if the aggregate costs set out in a notice under paragraph 7.2.1 exceed the amount paid by the service applicant under paragraph 7.1. However no procedures exist when the direct costs incurred by Jemena are less than the application fee paid by the service applicant. The AER considers that section 7 of the negotiating framework should be amended as set out in appendix K.

Clause 6.7.5(c)(9)—notification and consultation with affected users

Clause 8 (b) of United Energy's negotiating framework states that 'United Energy must notify and consult with any affected distribution network users and take reasonable steps to ensure that the provision of the negotiated distribution service does not result in non compliance with obligations to other distribution network users'. In order to maintain consistency with clause 6.7.5 (c) (9) of the NER, the AER considers this should be amended by removing the words 'take reasonable steps'. This will also ensure that responsibility for maintaining compliance with NER obligations for other network users remains with the DNSP.

Other changes

On page 5 of Jemena's negotiating framework the AER considers that '4.1.2 For the purpose of paragraph 4.1.1C, Jemena will have appropriate…' should be changed to '4.1.3 For the purpose of paragraph 4.1.2C, Jemena will have appropriate…'.

3.6 AER conclusion

In accordance with clause 6.12.1 (15) and (16), the AER's decisions on the negotiating framework and NDSC are as follows.

NDSC

For the reasons set out in section 3.5 above of this draft decision, the AER considers that the NDSC as proposed by the AER on 23 December 2009 are consistent and give effect to the negotiated distribution services principles in clause 6.7.1 of the NER.

The NDSC applying to CitiPower, Powercor, Jemena, SP AusNet and United Energy for the forthcoming regulatory control period are in appendix D of this draft decision. The AER's NDSC are also set out in the draft determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

Negotiating framework

Consistent with clause 6.12.3(g) of the NER, the AER does not approve the negotiating framework as proposed by Jemena, SP AusNet and United Energy, as they do not fully comply with the requirements of clause 6.7.5 of the NER. The AER's reasons for not approving these negotiating frameworks are as set out in section 3.5 of this draft decision. As required under clause 6.12.3(h) of the NER, the AER has identified the amendments to the negotiating frameworks that are required before it can approve them in accordance with the NER. The required amendments to each framework are set out in appendix C of this draft decision.

Consistent with clause 6.12.3(g) of the NER, the AER approves the negotiating frameworks proposed by CitiPower and Powercor. The AER considers that CitiPower's and Powercor's negotiating frameworks are consistent with the requirements of clause 6.7.5 of the NER.

The requirements for each negotiating framework are also set out in the draft determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

4 Control mechanisms for standard control services

4.1 Introduction

A distribution determination imposes controls over the prices, and revenues, that DNSPs may recover from providing direct control services. Under clause 6.2.2 of the National Electricity Rules (NER), direct control services are categorised as either standard control services or alternative control services. Classification of direct control services provided by the Victorian DNSPs is discussed in chapter 2 of this draft decision.

The AER has published a Framework and approach paper under clause 6.8.1 of the NER setting out the control mechanisms to apply to direct control services provided by the Victorian DNSPs during the forthcoming regulatory control period. For the Victorian DNSPs' standard control services, the control mechanism is a weighted average price cap (WAPC).[1] The formulaic expression of the WAPC formula as it applies in the forthcoming regulatory control period is set out in section 4.6.1 of this draft decision. This chapter discusses how the WAPC will be applied and sets out how the AER will determine compliance with the WAPC during the forthcoming regulatory control period.

This chapter also discusses the mechanism through which the Victorian DNSPs will recover transmission use of system charges (TUOS)—including adjustments for under or over recover of those charges—in the forthcoming regulatory control period.

Chapter 21 discusses how the AER will collect the specific information it requires from the Victorian DNSPs to assess their compliance with the WAPC formula and to assess their recovery of transmission use of system charges in the forthcoming regulatory control period.

The control mechanism and assessment of the Victorian DNSPs' proposed prices for public lighting services and other alternative control services are in chapters 19 and 20 respectively, of this draft decision.

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

4.2 Regulatory requirements

4.2.1 Control mechanisms for standard control services

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

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[1] AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, pp. 80 & 140.

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

4.2.2 Assigning customers to tariff classes

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

A DNSP is required to set out tariff classes as part of its pricing proposal. A DNSP's pricing proposal is submitted after the publication of the distribution determination under clause 6.18.2 of the NER. Clause 6.18.3 of the NER provides that separate tariff classes must be constituted for customers who are supplied with standard control services and alternative control services. The clause also requires that tariff classes be constituted with regard to the need to group customers together on an economically efficient basis and the need to avoid unnecessary transaction costs.

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

1. customers should be assigned to tariff classes on the basis of one or more of the following factors:
   i. the nature and extent of their usage;
   ii. the nature of their connection to the network;
   iii. whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement;
2. customers with a similar connection and usage profile should be treated on an equal basis;
3. however, customers with micro-generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile;
4. a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.

4.3 Summary of Victorian DNSP regulatory proposals

4.3.1 Weighted average price cap formula

Licence fee (L_t) factor

In the Essential Services Commission's (ESCV) 2006 electricity distribution price review (2006 EDPR), the Victorian DNSPs were required to pay licence fees to fund the ESCV, the AER and/or the Australian Energy Market Commission (AEMC) as appropriate.[2] These fees were recovered through the price controls. As discussed in the Framework and approach paper, the AER will retain the L_t factor in the control mechanism as long as licence fees are being charged.[3]

Jemena stated that the WAPC formula outlined in the Framework and approach paper[4] precludes the application of L_t in the form specified in volume 2 of the 2006 EDPR for the current regulatory control period.[5] Jemena proposed that the AER:

- reverts to the previous ESCV WAPC formula and L_t factor specification; or
- adopts the L_t specifications that corrects for the AER's proposed transition and ensures DNSPs receive the cost recovery intended by the ESCV formula that applied during the current regulatory control period.[6]

CitiPower and Powercor both submitted that the Framework and approach paper does not detail the basis of calculation for the L_t factor that is applied in the WAPC formula. CitiPower and Powercor proposed using the formula currently provided for in clause 2.3.15 of volume 2 of the 2006 EDPR.[7]

S factor true up

Jemena and United Energy both proposed a once-off adjustment in 2012 to account for 2010 performance outcomes under the ESCV's S factor (service performance) scheme, since this adjustment will not be able to be determined at the time of the AER's 2011–15 regulatory determination.

To account for this Jemena and United Energy proposed an s factor true-up correction factor (SFTUCF) be included in the WAPC formula as follows:

$$... \leq (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \times (1 + SFTUCF)$$ [8]

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2 ESCV, *Electricity distribution price review 2006–10: Final decision Volume 2*, December 2008, p. 71.

3 AER, *Framework and approach paper*, p. 75.

4 ibid., p. 140.

5 ESCV, *EDPR, 2006–10,Volume 2*, October 2005, pp. 22–23.

6 Jemena, *Regulatory proposal 2011–15*; 30 November 2009, p. 186.

7 CitiPower, *Regulatory proposal 2011 to 2015*, 30 November 2009; pp. 324–325; Powercor, *Regulatory proposal 2011 to 2015*, 30 November 2009, pp. 332–333.

8 Jemena, *Regulatory proposal*, pp.204–206.
United Energy, *Regulatory Proposal Appendix: Closing out the ESCV S factor scheme*, pp. 15–17.

Jemena and United Energy stated that this correction factor should apply to the WAPC formula only in 2012 and that there is no need for another factor to remove its effect.[9]

United Energy also proposed that 2011 tariffs include S'_t for 2009 performance and the t-6 component (as calculated under volume 2 of the 2006 EDPR); and proposed that 2012 tariffs include a factor that closes out the ESCV S factor scheme.[10]

Jemena stated that the S_t factor must be set either to:

- 0 in 2011 and 2012 if the AER retains its proposed WAPC specification
- 1 if the existing ESCV WAPC specification is retained.[11]

CitiPower and Powercor both proposed applying a multiplicative S factor true up correction factor to the WAPC formula in 2012 to account for actual performance in 2010 (they referred to this correction factor as the 't factor').[12] CitiPower and Powercor commented that the t factor would apply only to the price control for 2012 and that there is no need for a correction factor as the effect of the t factor is automatically removed at the 2016–20 regulatory control period.[13]

SP AusNet proposed that the S factor model be re-run once 2010 service performance becomes known. SP AusNet proposed a pass through mechanism to adjust prices for the difference between the original and post–2010 calculations of performance under the ESCV scheme for each year from 2012 to 2015. SP AusNet noted that it is unclear whether a change can be made to the price control mechanism to account for this proposed approach due to the restrictions the NER places on the AER regarding changes to the form of control. SP AusNet proposes a $0 materiality threshold for this cost pass through event.[14]

Allowing for tariff changes

CitiPower and Powercor both noted the need for the AER to specify how the WAPC will accommodate the introduction of new tariffs or tariff components and adjustments to existing tariffs or tariff components. CitiPower and Powercor proposed that the AER continues to apply the arrangements set out in clauses 2.2.5 to 2.2.8 of volume 2 of the 2006 EDPR.[15]

Side constraints

United Energy noted that under the 2006 EDPR, the average annual increase in each transmission and distribution tariff is constrained to CPI + 2 per cent. United Energy also noted that transmission charges are recovered through the maximum transmission

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9 Jemena, *Regulatory proposal*, p. 206: United Energy, *Appendix: Closing out the ESCV S factor scheme*, p. 16.

10 United Energy, *Regulatory proposal for Distribution Prices and Services January 2011–December 2015*, p. 201.

11 Jemena, *Regulatory proposal* p. 187.

12 CitiPower, *Regulatory proposal*, p. 319; Powercor, *Regulatory proposal*, p. 327.

13 CitiPower, *Regulatory proposal*, pp. 319–320; Powercor, *Regulatory proposal*, p. 328.

14 SP AusNet, *Electricity distribution price review, Regulatory proposal*, November 2009, p. 317.

15 CitiPower, *Regulatory proposal*, p. 326; Powercor, *Regulatory proposal*, p. 334.

revenue (MTR) mechanism, which sits outside the WAPC formula (see appendix F for details of the MTR formula as it applies in the forthcoming regulatory control period), and DNSPs can apply for an easing of the transmission constraint to allow for the pass through of large increases in transmission charges. United Energy proposed retaining this approach to the rebalancing constraint for 2011–15.[16]

4.3.2 Recovery of transmission tariffs

Premium feed-in tariff

Jemena proposed to retain the TUOS revenue control form specified in chapter 3 of volume 2 of the 2006 EDPR adjusted for premium feed-in tariff (PFIT) recovery in the forthcoming regulatory control period. Jemena considered that this would ensure consistency between regulatory periods and would prevent windfall losses or gains.[17] Jemena proposed that the PFIT rebate costs be defined as a recoverable payment under the maximum transmission revenue control in clause 3.3 of volume 2 of the 2006 EDPR. Jemena noted that this would require a new factor in the maximum transmission revenue formula to account for:

- systems enhancement and admin costs to implement PFIT
- ongoing administrative costs for PFIT
- rebates paid to customers under PFIT.[18]

CitiPower and Powercor also supported the retention of arrangements in the 2006 EDPR for TUOS recovery in the 2011–15 regulatory control period.[19] CitiPower and Powercor stated that the AER's Framework and approach paper did not specify how DNSPs can recover PFIT rebate costs. CitiPower and Powercor proposed that these costs be recovered through the G component of the mechanism in clause 3.3.4 of volume 2 of the 2006 EDPR.[20]

SP AusNet stated that it is uncertain about what type of customer (whether those with higher than average energy consumption or lower than average energy consumption) would be more likely to install solar panels under the Victorian government's PFIT scheme. As such SP AusNet considered it difficult to develop reasonable forecasts of the likely costs of providing credits under the scheme. SP AusNet therefore proposed a pass through mechanism for PFIT where a $250 000 materiality threshold applies.[21]

United Energy proposed an additional factor to be included in the WAPC formula, Ft, which recovers the 60c/kWh paid by United Energy to eligible customers under the PFIT scheme (United Energy noted that these amounts are not forecast in the proposal).[22] United Energy proposed that the administrative costs of managing and

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16 United Energy, *Regulatory proposal*, p. 203.
17 Jemena, *Regulatory proposal*, pp. 187–188.
18 ibid, pp. 188–189.
19 CitiPower, *Regulatory proposal*, p. 326–327; Powercor, *Regulatory proposal*, p. 334–335.
20 CitiPower, *Regulatory proposal*, p. 327; Powercor, *Regulatory proposal*, p. 335.
21 SP AusNet, *Regulatory proposal*, p. 316..
22 United Energy, *Regulatory proposal*, pp.201, 204.

complying with the PFIT be included in the forecast of 'Billing and revenue' under opex.[23]

Transmission connection charges

In their regulatory proposals SP AusNet and United Energy noted their understanding that clauses 6.18.2 and 6.18.7 of the NER allow DNSPs to recover TUOS charges but not the connection charges levied upon them by TNSPs.[24] SP AusNet and United Energy stated that clause 6.18.7 of the NER appears to seek to give effect to similar transmission cost recovery arrangements as those contained in Clause 3.3.2 of volume 2 of the 2006 EDPR[25].

SP AusNet proposed retaining the arrangements in clause 3.3.2 of volume 2 of the 2006 EDPR 'as it has been shown to work effectively over the current regulatory period.' SP AusNet also proposed carrying forward any unders / overs for transmission service cost recovery from the current regulatory control period into the forthcoming regulatory control period.[26]

In addition, SP AusNet noted that to maintain net present value (NPV) neutrality to the cash value of the unders /overs balance, any unders / overs should be subject to indexation based on either the WACC pertaining to the 2006 EDPR (for 2010 unders / overs) or the WACC approved as part of the AER’s 2011–2015 final decision (for unders / overs in the forthcoming regulatory period).[27]

SP AusNet also proposed to use the annual Pricing Proposal to report on its recovery of aggregate TUOS and transmission connection charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent network prices to account for over or under recovery of those charges. SP AusNet considered that this is consistent with clause 6.18.2 of the NER.[28]

Inter DNSP charges

CitiPower and Powercor both stated that inter DNSP charges should be treated the same way as transmission charges in that energy that flows through the grid that is not brought to account as distribution revenue should be recovered through the MTR mechanism.

CitiPower and Powercor proposed that these charges be recovered via the D component of the control mechanism in clause 3.3.4 of volume 2 of the 2006 EDPR as this would account for revenue not recovered through distribution use of system (DUOS) charges and prevent double counting.[29]

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23 ibid., p. 203–204.
24 SP AusNet, *Regulatory proposal*, pp. 350–351; United Energy, *Regulatory proposal*, pp. 201–202.
25 SP AusNet, *Regulatory proposal*, p. 350; United Energy, *Regulatory proposal*, p .201.
26 SP AusNet, *Regulatory proposal*, p .351.
27 ibid., p. 351.
28 ibid., p. 352.
29 CitiPower, *Regulatory proposal*, pp. 327–328; Powercor, *Regulatory proposal*, p. 335.

Avoided TUOS and avoided DUOS

CitiPower and Powercor stated that the AER's Framework and approach paper did not specify how DNSPs can recover avoided TUOS charges to embedded generators and avoided DUOS payments made to embedded generators where support arrangements are negotiated. CitiPower and Powercor proposed that these charges and payments be recovered via the G component of the mechanism in clause 3.3.4 of volume 2 of the 2006 EDPR.[30]

4.3.3 Tariff class assignment procedures

CitiPower and Powercor

CitiPower and Powercor proposed that it would use the following tariff classes in the forthcoming regulatory control period:

- residential
- small/medium business
- large low voltage
- high voltage
- sub transmission.[31]

CitiPower and Powercor stated that these tariff classes are sufficiently broad to ensure that all existing customers are assigned to their appropriate tariff class.

Regarding tariff assignment policy, CitiPower and Powercor cited appendix A of the AER's final decision for the New South Wales distribution determination as being 'largely appropriate for its circumstances.'[32]

SP AusNet

Having regard to clauses 6.12.1(17) and 6.18.4 of the NER, SP AusNet noted the following regarding its approach to assigning or reassigning customers to a tariff class:

- customers deemed to have usage greater than 160 MWh as at 1 January 2011 will be reassigned to a new critical peak demand price
  - SP AusNet envisages that all existing demand tariffs will be converted to a new critical peak demand price on a one-for-one basis—SP AusNet will outline its final position in its pricing proposal

[30] CitiPower, *Regulatory proposal*, p. 327; Powercor, *Regulatory proposal*, p. 335
[31] CitiPower, *Regulatory proposal*, pp. 329–330, Powercor, *Regulatory proposal*, pp. 336–337.
[32] CitiPower, *Regulatory proposal*, p. 330, Powercor, *Regulatory proposal*, p. 337.

- SP AusNet will reassign an existing residential or small commercial customer to a new time of use (TOU) tariff once an interval meter has been installed at the customer's premises and that meter becomes a remotely read interval meter

- SP AusNet will allocate all new customers (after 2011) based on the nature and extent of their usage, the nature of their connection to the network and the metering arrangements applicable to those customers

- in developing new tariffs, SP AusNet will comply with the requirements of clauses 6.18.4 and 6.18.6 of the NER and the WAPC formula determined according to the regulatory determination. SP AusNet will utilise the pricing proposals to illustrate its compliance with the relevant provisions of the NER.[33]

Having regard to clause 6.18.4(a)(4) of the NER, SP AusNet proposed to notify a customer's retailer in writing of the tariff class to which the customer has been assigned or reassigned prior to the assignment or reassignment occurring. SP AusNet advised that the notice would advise that the customer may request further information from SP AusNet and may object to the proposed assignment or reassignment.[34]

United Energy

United Energy stated its expectation that there will be refinements to existing tariffs during the 2011–15 regulatory control period. United Energy also stated that it will work with stakeholders to address pricing issues such as tariff reassignment in association with events such as the smart meter roll-out.[35]

4.4 Summary of submissions

4.4.1 Minimising revenue impacts of forecasting errors

The Energy Users Coalition of Victoria (EUCV) stated that networks operating under a price cap form of control tend to understate the growth in consumption (MWh). EUCV noted that if actual consumption exceeds forecast consumption, the network operator incurs a windfall gain. Consequently the EUCV supported 'the AER in securing independent assessments for forecast growth on which to base the price caps after it determines the appropriate revenue stream for Victorian DNSPs .'[36]

The EUCV noted that the ESCV and the Essential Services Commission of South Australia (ESCOSA) employed an adjustment mechanism (the Q factor) 'to minimise the impact of any gaming of the forecast consumption figures during the review

33 SP AusNet, *Regulatory proposal*, pp. 347–349.
34 ibid., p. 349.
35 United Energy, *Regulatory proposal*, p. 195.
36 EUCV, *Victorian electricity distribution revenue reset: A response by Energy Users Coalition of Victoria*, February 2010, p. 84.

process'[37] and considered that the AER should implement a mechanism that limits tariff gaming.[38]

The Total Environment Centre (TEC) cited recommendations made by the Institute for Sustainable Futures (ISF) to decouple DNSP profit from electricity sales. TEC noted that in a price cap regime such as for the Victorian distribution determination this could be achieved through a 'lost revenue adjustment' mechanism such as the New South Wales D factor.[39]

4.4.2 Tariff class assignment procedures

Origin Energy (Origin) sought clarification on whether the AER's decision on Interval Meter Reassignment Requirements[40] (IMRR) will extend beyond the conclusion of the current regulatory control period.[41] Origin also noted that requirements under the ESCV's Electricity Distribution Code (EDC) do not cover reassignment between tariffs outside the context of the Advanced Metering Infrastructure (AMI) rollout.[42]

Origin noted that CitiPower and Powercor regard the tariff reassignment procedures in the latest New South Wales distribution determination as being largely appropriate for its circumstances. Origin also noted the following requirement in that decision:

> A New South Wales DNSP must notify the customer concerned in writing of the tariff class to which the customer has been assigned or reassigned by the DNSP, prior to the assignment or reassignment occurring. If the DNSP does not know the identity of the customer then it must notify the customer's retailer instead.[43]

Origin considered that the DNSP should be required to inform the retailer prior to all tariff reassignments and not just when a DNSP does not have a customer's details. Origin proposed that communication should occur at least 20 business days prior to the proposed reassignment to ensure that retailers are able to pass on network costs in their entirety.[44]

Origin stated that it is unclear whether tariff reassignment requirements imply that the retailer must inform the customer of the reassignment on the DNSP's behalf. Origin recommended that the Victorian distribution determination stipulate that retailers not be required to initiate communication with customers regarding tariff assignment or reassignment on the DNSP's behalf. Origin further recommended that the Victorian

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37 ibid.

38 ibid., p. 88.

39 TEC, *Submission to Australian Energy Regulator on Victorian electricity distribution network service providers' regulatory proposals*, 11 February 2010, pp. 3–4.

40 AER, *Interval meter reassignment requirements*, May 2009.

41 The IMRR was published in May 2009 by the AER and outlines requirements that Victorian DNSPs must apply before they transfer customers to time of use tariffs. The IMRR implements requirements in the 2006 EDPR that makes provision for tariff reassignment to occur where a smart meter is installed at a customer's premises.

42 Origin Energy, *Re: Victorian DNSP regulatory proposals*, 11 February 2010, p. 7.

43 AER, – *New South Wales distribution determination final decision*, April 2009, p. 410.

44 Origin Energy, *Submission to the AER*. p. 8.

distribution determination should not mandate how retailers communicate with customers about changes in network tariffs.[45]

Origin also stated that if the AER allows United Energy's proposed new and innovative tariffs then there can be no mandatory assignment of customers for these tariffs, and that 'the full range of processes and procedures among distributor, retailer and customer require further examination.'[46]

The Ai Group (AIG) stated that industry must be provided with sufficient notice of new tariff arrangements to enable assessment of budgetary impacts and allow for adjustment to processes and practices. AIG also noted that it is important that information on new tariffs be conveyed in a manner that can be readily interpreted and compared with existing tariffs. Conditions of eligibility and any equipment requirements should also be clearly conveyed to the market.[47]

AIG also stated that the responsibility for liaising with customers regarding new distribution tariffs must be clearly identified and that a mechanism for consultation between customers, DNSPs and the AER should be set in place. AIG noted that electricity retailers are responsible for liaison with customers and that a DNSP's role is the delivery of electricity on a monopoly basis and it should not have contact with customers.[48]

4.5 Issues and AER considerations

4.5.1 WAPC formula

L_t factor

Victorian DNSP regulatory proposals

The AER considers the continuation of the approach in clause 2.3.15 of volume 2 of the 2006 EDPR to be appropriate for the forthcoming regulatory control period, with some modifications. In keeping with its Framework and approach paper, the AER will retain the $(1+L_t)$ component of the WAPC formula, which necessitates slight modification to the calculation of L_t. Specifically, the definition of L_t will be identical to that set out by the ESCV in clause 2.3.15(iii) of volume 2 of the 2006 EDPR, except that the AER has added a '–1' component. This will address Jemena's concern regarding the incorporation of the licence fee factor in the AER's WAPC formula.

The AER understands that licence fees incurred in the final years of the 2001–05 regulatory control period were not carried over into the 2006–10 regulatory control period. As such clause 2.3.15(ii) of volume 2 of the 2006 EDPR defined L_t for the calendar year ending 31 December 2006 as 1. As previously mentioned, the AER will carry over adjustments arising from the licence fee factor. Therefore, there is no equivalent to clause 2.3.15(ii) of volume 2 of the 2006 EDPR in this draft decision.

45 ibid.
46 ibid.
47 AIG, *Ai Group preliminary response to AER review of electricity network service proposals Victoria*, 12 February 2010, p. 2–3.
48 ibid., p. 3.

The AER has made slight modifications to the definition of L'_{t-1} (when compared to equivalent regulatory years in volume 2 of the 2006 EDPR) to enable the Victorian DNSPs to recover in 2011 the licence fees paid in 2010.

AER conclusion

The AER considers that the continuation of the L factor as set out in the Framework and approach paper is appropriate. The calculation of L_t for the forthcoming regulatory control period is set out in appendix E.2 of this draft decision.

S factor true up

Victorian DNSP regulatory proposals

Chapter 15 of this draft decision discusses the ESCV's S factor scheme and the transition to operating under the AER's Service Target Performance Incentive Scheme (STPIS). As the Victorian DNSPs have noted, actual performance for 2010 under the ESCV's S factor scheme will not be known at the time of the AER's final decision for this distribution determination.

SP AusNet proposed a pass through mechanism to adjust prices for the difference between the original and post–2010 calculations of performance under the ESCV scheme for each year from 2012–15. However, it is unclear whether or not a true up to correct for actual 2010 performance will meet the materiality threshold for pass through events. Further, the S factor true up relates to changes in revenue associated with S factor performance whereas the pass through regime in the NER refers to the passing through of material increases or decreases in ‘costs incurred’ as opposed to the revenue impact of the event.[49] Thus, while the S factor true up might, theoretically, constitute a pass through event, revenue impacts will not be able to be passed through as the definition of eligible pass through amount does not extend to changes in revenue. The AER therefore does not consider that it is able to implement the true up to correct for actual 2010 performance through a pass through mechanism. Pass through arrangements are discussed in chapter 16 of this draft decision.

Jemena, CitiPower, Powercor and United Energy proposed a correction factor,[50] to apply to the 2012 WAPC formula to account for actual 2010 performance under the ESCV S factor scheme. SP AusNet stated that it is unclear whether the NER permits changes to be made to the price control mechanism (as set out in the Framework and approach paper) to true up for actual 2010 performance.

The Framework and approach paper stated that the AER will carry over adjustments arising from the 2006 EDPR in relation to the S factor adjustments that will impact in the 2011–15 regulatory control period.[51] The Framework and approach paper also stated that the benefits and penalties accrued under the ESCV's S factor scheme in the current regulatory control period will not be incorporated in the price cap formula, but

49 See cl. 6.6.1 of the NER, and the definition of ‘eligible pass through amount’ in chapter 10 of the NER.

50 Hereafter, this correction factor is referred to as 'SFTUCF' (S factor true up correction factor).

51 AER, *Framework and approach paper*, p. 75.

rather as a building block element in the calculation of allowed revenue in the forthcoming regulatory control period.[52]

Given the constraints in the NER on amending the form of control from that specified in the Framework and approach paper,[53] the AER considers that the addition of a SFTUCF in the WAPC formula is not appropriate. Instead, the Victorian DNSPs will be allowed to recover the true up for actual 2010 performance under the ESCV S factor scheme in the 2016–20 regulatory control period. The AER expects that the true up amounts will not be material. This is because the estimates for 2010 performance are expected to reflect actual 2010 performance for the months leading up to the final decision.

AER conclusion

The AER considers that it is appropriate for the Victorian DNSPs to recover the true up for actual 2010 performance under the ESCV S factor scheme in the 2016–20 regulatory control period. The WAPC formula to be applied in the forthcoming regulatory control period is set out in section 4.6.1 and does not include a SFTUCF.

Allowing for tariff changes

Victorian DNSP regulatory proposals

CitiPower and Powercor proposed that the AER continues to apply the arrangements set out in clauses 2.2.5 to 2.2.8 of volume 2 of the 2006 EDPR regarding how the WAPC formula will accommodate the introduction of new tariffs or tariff components.

Clauses 2.2.5–2.2.8 of volume 2 of the 2006 EDPR specify the information DNSPs were required to submit to the ESCV prior to the commencement of the calendar year in which new distribution tariffs (or tariff components) are to apply. As the AER does not consider it appropriate to specify annual information requirements in a distribution determination, it will specify the information DNSPs are required to submit to the AER in a regulatory information notice (RIN).

Appendix E sets out how compliance with the WAPC formula is to be demonstrated under clause 6.12.1(13) of the NER. In particular, appendix E.1 provides the principles on how new tariffs or tariff components are to be incorporated into the WAPC formula and side constraints—these arrangements are consistent with the approach in the AER's recent distribution determinations in New South Wales and South Australia. The AER considers that it is appropriate to collect specific information required to demonstrate compliance with the WAPC formula and side constraints (such as those requested in clauses 2.2.5–2.2.8 of the 2006 EDPR) through a RIN.

The AER proposes to issue a RIN to the Victorian DNSPs for the purposes outlined above.

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52 ibid., p. 94.
53 NER, cl, 6.12.3(c).

AER conclusion

Appendix E of this draft decision provides the principles on how new tariffs or tariff components are to be incorporated into the WAPC formula and side constraints.

Side constraints

Victorian DNSP regulatory proposals

Regarding United Energy's proposal, the AER notes that clause 6.18.6 of the NER specifies the side constraints applying to tariff classes related to the provision of standard control services in the forthcoming regulatory period. Clause 6.18.6 of the NER limits the expected weighted average revenue raised (from a tariff class for a regulatory year of a regulatory control period). It must not exceed the expected weighted average revenue for the preceding regulatory year by more than the greater of:

- the (CPI – X) limit on the increase of the DNSP’s expected weighted average revenue between the two regulatory years plus 2 per cent
- (CPI + 2 per cent).

The AER considers that this is consistent with the approach adopted in the 2006 EDPR.

The AER notes that the side constraints contained in this draft decision do not apply for the first year of the forthcoming regulatory control period. Clause 6.18.6(b) of the NER prevents side constraints from applying between regulatory control periods.[54] The side constraint formula set out in section 4.6.2 is intended to first apply to the prices for 2012, when these prices will be compared against the prices for 2011.

The AER also notes clause 6.18.6(e) of the NER which states that clause 6.18.6 of the NER:

> does not, however, limit the extent a tariff for customers with remotely-read interval metering or other similar metering technology may vary according to the time or other circumstances of the customer's usage.

Accordingly, under the NER the side constraints applying to tariff classes relating to the provision of standard control services may not necessarily apply where AMI (that is, smart meters) and time of use tariffs are in place. The AER will assess the pricing implications of cases relevant to clause 6.18.6(e) of the NER when the Victorian DNSPs submit the relevant information as part of their pricing proposals.

AER conclusion

The side constraints on tariff classes related to the provision of standard control services are provided in clause 6.18.6 of the NER. The side constraints to apply to tariff classes related to the provision of standard control services is outlined in section 4.6.2 of this draft decision.

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[54] This is consistent with the approach taken in the New South Wales, ACT, South Australia and Queensland distribution determinations.

Minimising revenue impacts of forecasting errors

Submissions on DNSP proposals

In its submission, the EUCV recommended that the AER secure independent assessments for forecast energy consumption growth on which to base the price caps. The AER has commissioned ACIL Tasman to assess the DNSPs' growth forecasts. This is discussed in chapter 5 of this draft decision which sets out the AER's approach to demand forecasting. In terms of the EUCV's submission on the introduction of a mechanism similar to ESCOSA's Q factor,[55] as discussed in section 4.5.1 the AER is constrained by the NER regarding the changes it can make to the control mechanism as set out in the Framework and approach paper.

In relation to TEC's proposal that a D factor be applied in Victoria as it has in New South Wales, chapter 17 of this draft decision on the application of the AER's demand management incentive scheme (DMIS) discusses the AER's consideration of this proposal.

Correction to appendix F of the Framework and approach paper

Definition of CPI_t

The AER recognises that clause 6.12.3(c) requires it to apply the control mechanism as set out in the Framework and approach paper. However the control mechanism as set out in appendix F of the Framework and approach paper contained an error in the definition of CPI_t.

The Framework and approach paper defined CPI_t as the All Groups Index Number for eight capital cities published by the Australian Bureau of Statistics (ABS) for year t divided by the corresponding All Groups Index Number for year t–1. This in effect provides the index which converts prices in year t–1 into year t prices. However, CPI_t as it applies in the WAPC formula should capture the rate of change of prices from year t–1 to year t. That is, the definition of CPI_t as it stands in the Framework and approach paper, minus one. This is consistent with the definition and application of CPI_t in the 2006 EDPR. The 'minus one' component of the definition was inadvertently omitted from the Framework and approach paper.

For this reason the AER is of the view that the definition of CPI_t should be amended as set out in section 4.6.1 of this draft decision.

Appendix F of the Framework and approach paper referred to the use of March quarter CPI in the calculation of CPI_t.[56] However the AER also stated in the Framework and approach paper that CPI in the WAPC formula 'is as specified in the NER.'[57] Chapter 10 of the NER states that CPI is:

> As at a particular time, the Consumer Price Index: All Groups Index Number, weighted average of eight capital cities published by the Australian Bureau of Statistics for the most recent quarter that precedes that particular time…

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55 ESCOSA, *2005–2010 Electricity distribution price determination part A – Statement of reasons*, April 2005 pp. 184–185.

56 AER, *Framework and approach paper*, p. 145.

57 ibid., p. 75.

As required by clause 6.18.2 of the NER, the Victorian DNSPs submit pricing proposals within 15 days after the publication of the distribution determination for the first year of a regulatory control period, or at least 2 months prior to the commencement of a regulatory year for the second and subsequent years of a regulatory control period. The September quarter is the most recent quarter for the purpose of the pricing proposals. As specified in section 4.6.1 of this draft decision, the AER considers it appropriate that September quarter CPI figures be used in the calculation of CPI_t for the WAPC formula because this is consistent with the NER and with the approach adopted by the ESCV.

Pass throughs

The Framework and approach paper was silent on the mechanism through which pass throughs are to be recovered.

The AER has decided that it will add an explicit qualitative term to the WAPC formula for any approved cost pass throughs. The AER considers that pass throughs in the forthcoming regulatory control period cannot be recovered through any other mechanism under the NER.

The addition of this term clarifies how pass throughs will be treated under the WAPC and is consistent with the approach used by the AER for the New South Wales and South Australian DNSPs. The AER notes that the Victorian DNSPs will be required to demonstrate in its pricing proposal that any increase/decrease in 'pass $through_t$' has been included in the tariffs/tariff components of those tariff classes which gave rise to the expenses to be passed through.

The WAPC formula for the Victorian DNSPs in the forthcoming regulatory control period is set out in section 4.6.1 of this draft decision.

4.5.2 Recovery of transmission tariffs

PFIT

Victorian DNSP regulatory proposals

Under the Victorian PFIT amendment to the *Electricity Industry Amendment Act 2000* (Vic),[58] DNSPs are required to pay a rebate of 60 cents per kilowatt hour to certain classes of customer for the electricity these customers feed into the DNSPs’ networks (that is, through customer solar electricity units).

The AER is mindful that DNSPs recovered PFIT rebates paid to customers through a pass through mechanism in the current regulatory control period. This was required by s.40FI(1) of the *Electricity Industry Amendment (Premium Solar Feed-in Tariff) Act 2009* (Vic), which stated that such payments by DNSPs were a pass through event with a material financial impact on the DNSP for the purposes of the 2006–2010 EDPR. However as discussed in chapter 16 of this draft decision, the AER's position is not to apply a pass through mechanism to PFIT cost recovery as proposed by SP AusNet.

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[58] S.40FA, Electricity Industry Act 2000 (Vic).

In their regulatory proposals Jemena, CitiPower, and Powercor proposed that rebates paid to customers by DNSPs under the PFIT scheme should be recovered in the forthcoming regulatory control period through a mechanism similar to the 'G component' of the maximum transmission revenue (MTR) mechanism of clause 3.3 of the 2006 EDPR.

Clause 3.3 of volume 2 of the 2006 EDPR concerns the Maximum Transmission Revenue (MTR) control which was applied when the ESCV considered whether or not to verify DNSPs’ proposed transmission tariffs. This control took the form specified in clauses 3.3.1 – 3.3.5 of volume 2 of the 2006 EDPR.

The G component represents the amount the Victorian DNSPs pay to embedded generators in a calendar year. Customers receiving payment under PFIT schemes can be considered as embedded generators under the NER. However, as discussed in the sections on transmission connection charges and avoided TUOS and DUOS below, the AER does not consider it appropriate that payments to embedded generators be recovered under clause 6.18.7 of the NER because it does not fall within the definition of TUOS under the NER. Hence, under the NER payments under PFIT schemes would not be able to be recovered through a mechanism similar to the 'G component' of the MTR mechanism of clause 3.3 of the 2006 EDPR.

The AER notes that the AEMC is currently considering a rule change (the draft clause 6.18.7A of the NER, published 8 April 2010), which will provide a mechanism for the recovery of PFIT payments including a true-up mechanism to be implemented for the over and under recovery of PFIT rebate payments.[59] Subject to the outcome of this rule change process the AER will consider in the final decision how rebate payments under the PFIT scheme are to be recovered in the forthcoming regulatory control period.

The AER considers that United Energy’s proposal to include the administrative costs of managing and complying with the PFIT scheme in forecast opex under 'Billing and Revenue' is not permissible under the NER. The AER is only able to accept forecast opex under clause 6.5.6(c) of the NER if it is satisfied that the total of the opex reasonably reflects the opex criteria. These criteria always refer back to the opex objectives. It is unclear how the administrative costs of the PFIT scheme relate to the opex objectives listed in clause 6.5.6(a) of the NER. Specifically, these objectives concern standard control services. The definition of standard control services in Chapter 10 of the NER ultimately requires there to be a 'distribution service'. Distribution service is, in turn, defined as a 'service provided by means of, or in connection with, a distribution system.' Consequently, it appears that administrative costs cannot be considered as distribution services under the NER. As an aside, the AER notes that it is unclear whether draft rule 6.18.7A, which the AEMC is currently considering, allows for the recovery of administrative costs through its under/over cost recovery framework. The AER considers that this issue (of including administrative costs of managing and complying with PFIT schemes) would have been explicitly considered in the AEMC consultation process if it was intended for recovery through either the (draft) clause 6.18.7A or as an item in opex.

59 See www.aemc.gov.au.

AER conclusion

The AER does not consider it appropriate that payments made under the Victorian PFIT scheme be recovered under clause 6.18.7 of the NER. The AER also does not consider it appropriate that payments made under the Victorian PFIT scheme be recovered through a pass through mechanism. The AER considers that the inclusion of the administrative costs of managing and complying with the PFIT scheme in forecast opex is not appropriate.

Transmission connection charges

Victorian DNSP regulatory proposals

In their regulatory proposals SP AusNet and United Energy noted their understanding that clauses 6.18.2 and 6.18.7 of the NER allow DNSPs to recover at the pricing proposal stage TUOS charges but not the connection charges levied upon them by TNSPs.[60] The AER agrees with this interpretation of the NER.

The Victorian DNSPs (except for United Energy) have proposed a continuation of the approach in chapter 3 of volume 2 of the 2006 EDPR for the recovery of transmission related payments (which the Independent Pricing and Regulatory Tribunal has previously described as including TUOS payments, transmission connection payments, inter-DNSP payments and avoided TUOS payments)[61] over the forthcoming regulatory control period. Clause 6.18.7 of the NER provides a mechanism through which a DNSP may pass on to consumers charges to be incurred for TUOS services. However, as noted above, the AER agrees with SP AusNet's and United Energy's interpretation that TUOS is defined under the NER so as to exclude transmission connection charges. The AER therefore does not consider it appropriate that transmission connection charges be recovered under clause 6.18.7 of the NER, that is through an approach similar to that adopted in chapter 3 of volume 2 of the 2006 EDPR.

The AER has been advised that the Victorian DNSPs have contacted the AEMC to initiate a rule change proposal that would enable the recovery of transmission connection charges under 6.18.7 of the NER.[62] Subject to the outcome of this rule change process the AER will consider in the final decision how transmission connection charges are to be recovered in the forthcoming regulatory control period.

In relation to NPV neutrality of the cash value of the unders / overs balance, the AER considers that any unders / overs should be subject to indexation based on the WACC approved as part of the AER’s 2011–2015 final decision (for 2010 unders / overs and for unders / overs in the forthcoming regulatory control period). The AER considers that this is administratively simple, and is consistent with the approach adopted by the ESCV in the 2006 EDPR.

The AER considers that SP AusNet's proposal to use the annual pricing proposal to report on its recovery of aggregate transmission tariffs and adjustments to be made to

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60 SP AusNet, *Regulatory proposal*, pp. 350–351; United Energy, *Regulatory proposal*, pp. 201–202.

61 Independent Pricing and Regulatory Tribunal, *NSW electricity distribution pricing 2004/05 to 2008/09*, June 2004, p. 4.

62 United Energy, email to AER staff, 19 March 2010.

account for unders / overs is appropriate. The AER considers that this is consistent with the requirements of clause 6.18.2 of the NER.

AER conclusion

The AER does not consider it appropriate that transmission connection charges be recovered under clause 6.18.7 of the NER.

The approach to the recovery of charges incurred for TUOS services in the forthcoming regulatory control period is set out in appendix F of this draft decision.

The AER considers that any unders / overs should be subject to indexation based on the WACC approved as part of the AER's 2011–2015 final decision (for 2010 unders / overs and for unders / overs in the forthcoming regulatory control period).

The AER considers that the Victorian DNSPs' use of the annual pricing proposal to report on its recovery of aggregate transmission tariffs and adjustments to be made to account for unders / overs is appropriate.

Inter DNSP charges

Victorian DNSP regulatory proposals

The AER has considered the ESCV arrangements when considering CitiPower's and Powercor's proposal regarding inter-DNSP charges. Regarding the recovery of inter-DNSP charges, the AER has assumed that CitiPower's and Powercor's proposal refers to clause 3.3 of volume 2 of the 2006 EDPR generally, and not clause 3.3.4 specifically, as clause 3.3.4 is an element of clause 3.3.1.

As noted previously, clause 6.18.7 of the NER provides a mechanism through which a DNSP may pass on to consumers charges to be incurred for TUOS services. The AER does not consider that inter-DNSP charges fall within the definition of TUOS under the NER as they are not related to the use of the transmission network.[63] The AER therefore does not consider it appropriate that inter-DNSP charges be recovered under clause 6.18.7 of the NER, that is through an approach similar to that adopted in chapter 3 of volume 2 of the 2006 EDPR.

AER conclusion

The AER does not consider it appropriate that inter-DNSP charges be recovered under clause 6.18.7 of the NER.

Avoided TUOS and avoided DUOS

Victorian DNSP regulatory proposals

Regarding CitiPower's and Powercor's proposal on avoided TUOS and DUOS, as noted previously clause 6.18.7 of the NER provides a mechanism through which a DNSP may pass on to consumers charges to be incurred for TUOS services. The AER does not consider that either avoided TUOS or avoided DUOS charges fall within the definition of TUOS under the NER as they are not related to the use of the

[63] Chapter 10 of the NER defines TUOS (more specifically, customer TUOS) as 'a service provided to a *Transmission Network User* for use of the *transmission network* for the conveyance of electricity…' (Note that italicised terms are defined in chapter 10 of the NER).

transmission network. The AER therefore does not consider it appropriate that avoided TUOS and avoided DUOS charges be recovered under clause 6.18.7 of the NER, that is through an approach similar to that adopted in chapter 3 of volume 2 of the 2006 EDPR.

The AER considers that the Victorian DNSPs can raise the issue of recovery of inter-DNSP charges and avoided TUOS and DUOS charges with the AEMC as part of consultation on their proposed rule change regarding recovery of transmission connection charges. Subject to the outcome of this rule change process the AER will consider in the final decision how these charges are to be recovered in the forthcoming regulatory control period.

AER conclusion

The AER does not consider it appropriate that avoided TUOS and avoided DUOS charges be recovered under clause 6.18.7 of the NER.

4.5.3 Assigning customers to tariff classes

Victorian DNSP regulatory proposals

The AER notes clause 6.12.1(17) of the NER which requires the AER to make a decision on the procedures for assigning or reassigning customers to tariff classes. There is no requirement on the Victorian DNSPs to propose such procedures and consequently the AER must develop the required procedures.

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

The AER notes in respect of the submissions made by CitiPower and Powercor that the procedures for assigning or reassigning customers to tariff classes in appendix G are consistent with those in the AER's recent distribution determinations in New South Wales, Queensland and South Australia. The AER has made some modifications as explained in appendix G and in the following sections.

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

An effective system of assessment and review under clause 6.18.4(a)(4) may, apart from providing for internal review, also include an effective external system of review as the next step in the process of escalation. Customers dissatisfied by a decision of the internal review process should have access to the external review body. In the AER’s New South Wales distribution determinations the AER recognised the New South Wales Water and Energy Ombudsman as the external review body for small retail customers.[64] For the Victorian regulatory determination, the AER considers the Energy and Water Ombudsman (Victoria) (EWOV) as the external review body for small retail customers.

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64 AER, *NSW distribution determination,*, April 2009, pp. 24–25.

In the event of a dispute between a DNSP and a customer about assignment or reassignment of a customer to a tariff class, such a 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.[65] The AER has included in the procedures for assigning customers to tariff classes (see appendix G) that the Victorian DNSPs inform customers of the availability of the dispute resolution mechanism under Part 10 of the NEL.

Regarding SP AusNet's proposal to notify a customer's retailer of the tariff class to which the customer has been assigned or reassigned prior to the assignment or reassignment occurring, the AER considers that DNSPs are to notify customers directly of any tariff class assignment or reassignment. This is discussed below.

SP AusNet also stated that it will reassign an existing residential or small commercial customer to a new time of use (TOU) tariff once an interval meter has been installed at the customer's premises and that meter becomes a remotely read interval meter. It is noted that the Victorian Government has announced a moratorium on the introduction of TOU tariffs.[66]

Submissions on DNSP proposals

Regarding Origin Energy's submission, the IMRR recommended that a new clause 9.1.14 be inserted into the ESCV's Electricity Distribution Code (the Code) outlining the obligations of a DNSP to inform customers with annual consumption of less than 20 MWh of a possible future reassignment to time of use tariffs.[67] The new clause 9.1.14 has been incorporated into the Code[68] and it is the AER's understanding that the Victorian DNSPs will be subject to the Code in the 2011–2015 regulatory control period.

The IMRR also clarified that 'reassignment to a TOU network tariff by a distributor can only occur if the distributors' network charges are set on the basis of interval data.'[69] This requirement has been reiterated in the procedures for tariff class assignment/reassignment in appendix G of this draft decision. It is noted that appendix G outlines the procedures for assigning/reassigning customers to tariff classes both inside and outside the context of the AMI rollout.

Regarding Origin's comment on clause 6 of the tariff class assignment procedures in the New South Wales distribution determination, it is noted that the AER's distribution determination does not impose any obligation on electricity retailers to notify customers of any tariff class assignment or reassignment made by a DNSP.

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

66 The Hon. Peter Batchelor MP, Minister for Energy and Resources (Victoria), Media Release, *Moratorium to ensure smooth smart meter roll-out*, 22 March 2010.

67 AER, *Interval meter reassignment requirements*, May 2009, p. 22.

68 ESCV, *Electricity Distribution Code*, August 2009, p. 25–26.

69 AER, *Interval meter reassignment requirements*, May 2009, p. 21.

The AER notes that the market settlement and transfer solution procedures (MSATS) require a DNSP to notify the tariff code applicable to a customer or any changes to it. Retailers receive notification of tariff class changes from the DNSPs through these procedures, and therefore the AER considers that a separate requirement on DNSPs to inform retailers of tariff class assignments/ reassignments (as suggested by Origin) is not necessary.

The notification obligation under the AER's procedure for assigning or reassigning customers to tariff classes is part of a system of assessment and review. As noted earlier, an effective system of assessment and review is required by the NER.[70] This system recognises that the customer has the right to object to tariff class assignment or reassignment decisions and therefore the customer should be directly notified by the DNSP. The AER considers that this approach, based on direct notification, right of objection and external dispute resolution underpins the effective system of assessment and review.

Regarding the packaging of services as part of a tariff (such as load control, premium services), United Energy has informed the AER that such services are to be implemented on a trial basis in the forthcoming regulatory control period. For example, trials for direct load control services will be funded from the DMIS.[71] The AER understands that United Energy services such as direct load control may progress beyond the trial stage during the forthcoming regulatory control period and that customers may elect to receive such services through their retailer. The AER also understands that United Energy currently does not have procedures for assigning/reassigning customers who decide to receive such services, but will develop procedures if such services are provided as part of a tariff. When developing such procedures a DNSP must have regard to the procedures set out in appendix G of this draft decision, as well as clause 6.18.3 of the NER. The AER considers that these requirements would ensure that customers electing to receive services such as load control are assigned to the appropriate tariff class.

Regarding AIG's submission, it is noted that clause 6 of appendix G of this draft decision requires a Victorian DNSP to notify a customer in writing of tariff assignment/reassignment prior to that assignment or reassignment occurring.

The procedures in appendix G do not provide a timeframe for new tariff arrangements to be assessed by customers in relation to budgetary impacts and required adjustment to processes and practices, as recommended by AIG. However clauses 7–10 outline the information that must be included in the notice, including advice that the customer may request further information from the DNSP and that it may object to the proposed assignment or reassignment. If the customer objects to the tariff class reassignment and in the event that the customer's objection is upheld by the relevant review body, then it is entitled to have its prices corrected to reconcile any price impacts which may have occurred since the DNSP's assignment/reassignment decision under clause 10 of appendix G.

70 NER, cl. 6.8.4(a)(4).
71 United Energy, email to AER staff, United Energy 24 February 2010.

AER conclusion

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

4.6 AER conclusion

As part of their pricing proposals, the Victorian DNSPs must submit to the AER proposed tariffs and charging parameters which correspond to the price terms contained in the WAPC and side constraint equations set out below. 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.

In accordance with clause 6.12.1(11), of the NER, the AER's WAPC formula is set out below. In accordance with clause 6.12.1 (13), compliance with the WAPC formula will be monitored as per appendix E of this draft decision. In accordance with clause 6.12.1 (17) and (19) of the NER, the procedures for assigning tariffs, and for reporting the recovery of TUOS charges is as per appendices G and F of this draft decision. The AER's WAPC formula and side constraints are also set out in the draft determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

4.6.1 Weighted average price cap

For the forthcoming regulatory control period

The WAPC formula to apply to the Victorian DNSPs for the forthcoming regulatory control period is:

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

where a DNSP has *n distribution tariffs*, which each have up to *m distribution tariff components*, and where:

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

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

CPI_t is calculated as follows:

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

divided by

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

minus one.

X_t is the value of X for year t of the regulatory control period as determined by the AER in chapter 18 of this draft decision ;

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

L_t is the licence fee pass through adjustment to be applied in regulatory year t in accordance with appendix E.2 of this draft decision; and

$passthrough_t$ 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

4.6.2 Side constraints

For the forthcoming regulatory control period

The side constraints formula to apply to the Victorian DNSPs for the forthcoming regulatory control period is:

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

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

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

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

q_{t-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 value of X for year t of the regulatory control period as determined by the AER in chapter 18 of this draft decision. If X>0, then X will be set equal to zero for the purposes of the side constraint formula

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

L_t is the licence fee pass through adjustment to be applied in regulatory year t

CPI_t is defined as set out in section 4.6.1 of this draft decision.

$passthrough_t$ 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

4.6.3 Ring fencing

Ring fencing guidelines form an integral part of a regulatory regime. Clause 11.14.5(b)(3) of the NER states that ring fencing guidelines in force in a participating jurisdiction immediately before the AER's assumption of regulatory responsibility (transitional guidelines) continue in force for that jurisdiction. The ESCV's ring fencing guidelines are therefore applicable transitional guidelines for Victoria.[72] Consistent with clause 11.14.5(c) of the NER these transitional guidelines will be regarded as the AER's guidelines and any reference to the jurisdictional regulator will be considered a reference to the AER until amended, revoked or otherwise replaced by the AER.

The transitional guidelines set out specific requirements in regard to:

- non-discriminatory conduct by DNSPs
- provision of information by DNSPs to retail businesses
- separation of organisational units
- branding, marketing and customer communications
- outsourcing.

The ESCV did not include any specific compliance measures in the electricity ring fencing guideline. Instead, it relied on its general approach to compliance, including investigating complaints and conducting periodic compliance audits, to assess compliance with the guideline.[73] The AER will continue with this approach in the forthcoming regulatory control period.

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72 ESCV, *Electricity industry guideline no.17: Electricity ring-fencing Issue 1*, October 2004.
73 ESCV, *Final decision: Ring-fencing in the Victorian electricity industry*, October 2004, p .24.

To the extent that the ESCV’s reporting guidelines do not cover additional matters addressed in this draft decision, such as the incentive schemes discussed in chapters 14, 15 and 17, chapter 21 of this draft decision sets out monitoring and compliance requirements.

5 Growth forecasts

5.1 Introduction

This chapter outlines the AER's assessment of the Victorian DNSPs' growth forecasts for the forthcoming regulatory control period. 'Growth forecasts' refer to forecasts of maximum demand, energy sales and customer numbers.

Maximum demand (measured in MW or MVa) is the highest level of network capacity required to supply electricity at a single point in time and is a key driver of load driven capital expenditure (capex) requirements. Energy sales forecasts (measured in GWh) are used to determine the expected revenue of the DNSP and are a key input to the post-tax revenue model (PTRM) where X factors are set to equate building block requirements to expected revenues under the weighted average price cap (WAPC) form of control mechanism. Customer number forecasts are similarly important in determining expected revenues and are also a driver of connection related capex.

5.2 Regulatory requirements

Clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the National Electricity Rules (NER) require the AER to assess whether a DNSP's forecast of operating expenditure (opex) and capex reasonably reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex/capex objectives. The opex and capex objectives are set out in clauses 6.5.6(a) and 6.5.7(a) of the NER, respectively. Clauses 6.5.7(a)(1) and 6.5.6(a)(1) of the NER state that a building block proposal must contain forecasts of total opex and capex respectively that the DNSP considers are required, inter alia, to meet or manage the expected demand for standard control services over the forthcoming regulatory control period.

Clause 6.12.1(10) of the NER requires the AER to make a decision on appropriate amounts, values or inputs. These include forecasts of peak demand, energy consumption and customer numbers which are inputs to the capex and opex assessments, and the PTRM and subsequently X factors.

5.3 Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs each engaged the National Institute of Economic and Industry Research (NIEIR) to prepare energy and customer number forecasts for their networks. NIEIR's reports for each DNSP were provided as attachments to their regulatory proposals. NIEIR also prepared 'top down' maximum demand forecasts for each DNSP which in most cases were used as a cross check for the Victorian DNSPs' own 'bottom up' demand forecasts.[1]

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[1] NIEIR, *Maximum demand forecasts for CitiPower terminal stations to 2019—Summer and winter and coincident and non coincident*, November 2009; NIEIR, *Electricity sales and customer number forecasts for the CitiPower region to 2019*, November 2009; NIEIR, *Maximum demand forecasts for Powercor Australia terminal stations to 2019—Summer and winter and coincident and non coincident*, November 2009; NIEIR, *Electricity sales and customer number forecasts for*

NIEIR prepared both coincident and non-coincident maximum demand forecasts at the system level for each DNSP. Coincident forecasts reflect the maximum demand at a point in the network which coincides with the maximum demand for the entire network (that is, the single maximum demand half hour per year for each DNSP), while non-coincident forecasts reflect the absolute maximum demand experienced at that point in the network (which may not coincide with the system peak). When aggregated for each network element, coincident forecasts portray the true system maximum demand, while non-coincident forecasts are more reflective of the capacity requirements at particular points in the network and are the main driver for the Victorian DNSPs' growth driven capex.

The Victorian DNSPs produce maximum demand forecasts at both 10 and 50 per cent probability of exceedence (PoE). PoE demand is that which is likely to be met or exceeded over a specified time frame. For example, the 50 (10) PoE demand level is the annual maximum demand level that is expected to be met or exceeded 50 per cent (10 per cent) of the time, or one in every two (ten) years.

In general, NIEIR's top down demand forecasts are based on macro variables, such as economic growth, air conditioner use and the likely impact of numerous Government policy changes. The Victorian DNSPs' bottom up demand forecasts reflect information specific to particular areas of the network, such as expected large loads and particular growth rates.

The energy consumption forecasts prepared by NIEIR and submitted by the Victorian DNSPs involve separating consumption into different customer classes and estimating them separately, before aggregating the forecasts for each DNSP. NIEIR then adjusted these for the impact of government policies, including the rollout of Advanced Metering Infrastructure (AMI). In contrast to the other DNSPs, SP AusNet performed its own adjustments to NIEIR's forecasts to account for expected tariff impacts, including those arising out of AMI.

NIEIR's approach to forecasting customer numbers reflects estimates from its Victorian construction industry model, which are disaggregated into Local Government Area forecasts relevant to the Victorian DNSPs' network regions.

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the Powercor Australia region to 2019, November 2009; NIEIR, *Maximum demand forecasts for Jemena Electricity Networks terminal stations to 2019—Summer and winter and coincident and non coincident*, November 2009; NIEIR, *Electrical sales and customer number forecasts for the JEN electricity region to 2019*, November 2009; NIEIR, *Maximum demand forecasts for SP AusNet terminal stations to 2019—Summer and winter and coincident and non coincident*, November 2009; NIEIR, *Electricity sales and customer number forecasts for the SP AusNet distribution region to 2019 (class and network tariff)*, November 2009; NIEIR, *Maximum demand forecasts for United Energy terminal stations to 2019—Summer and winter and coincident and non coincident*, November 2009; NIEIR, *Electricity sales and customer number forecasts for the United Energy region to 2019 (class and network tariff)*, November 2009. The AER notes that NIEIR prepared individual reports for each DNSP's maximum demand, and energy and customer number forecasts, however the areas discussing methodology, impact of economic growth, Government policies are largely identical in each DNSP's reports. Accordingly, when referring to the NIEIR reports, this draft determination will refer to the report prepared for SP AusNet, however the quote can be inferred to be identical for each DNSP.

Tables 5.1 to 5.5 summarise the Victorian DNSPs' maximum demand, energy and customer number forecasts. While energy and customer number forecasts are presented in a comparable manner, maximum demand forecasts vary in how they have been presented to the AER.

Overall the Victorian DNSPs predict average annual increases in maximum demand of between 2.2 and 4.4 per cent over the forthcoming regulatory control period. The main driver for these increases is higher air conditioning penetration, contributing to temperature sensitive load. By contrast, the Victorian DNSPs expect energy consumption to decline at an annual rate of between 0.6 and 1.4 per cent per annum. This reflects the impact of various energy efficiency policies and responses to higher prices arising out of the carbon pollution reduction scheme (CPRS) and time of use tariff arrangements enabled by the AMI program. Customer numbers are expected to increase at a rate of between 0.7 and 1.4 per cent per annum, mainly reflecting population growth.

Table 5.1 Summary CitiPower proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW)[a]	1 535	1 577	1 679	1 661	1 705	2.7
Energy (GWh)	6 030	6 046	5 944	5 828	5 836	–0.8
Customer numbers	316 243	321 189	324 686	328 584	334 914	1.4

(a) Summation of non-coincident zone substation maximum demands
Source: CitiPower, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 32.

Table 5.2 Summary of Powercor proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW)[a]	2 666	2 739	2 804	2 857	2 919	2.3%
Energy (GWh)	10 700	10 643	10 465	10 307	10 290	–1.0%
Customer numbers	715 541	727 610	739 714	752 719	766 214	1.7%

(a) Summation of demand at non-coincident zone substation and 22kV terminal station points of supply
Source: Powercor, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 32.

Table 5.3 Summary of Jemena proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW) [a]	1 002	1 027	1 051	1 077	1 093	2.2
Energy (GWh)	4 246	4 201	4 105	4 024	4 011	–1.4
Customer numbers	308 296	313 257	317 334	320 907	325 049	1.3

(a) Network coincident maximum demands based on 50 PoE.
Source: Jemena, *Regulatory Proposal 2011–15*, 30 November 2009, p. 64; Jemena PTRM.

Table 5.4 Summary of SP AusNet proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW)	2 005	2 093	2 185	2 281	2 381	4.4
Energy (GWh)	7 821	7 756	7 622	7 563	7 638	–0.6
Customer numbers	634 190	644 899	654 309	663 159	672 912	1.5

Source: SP AusNet, *Electricity Distribution Price Review, Regulatory Proposal*, November 2009, p. 77.

Table 5.5 Summary of United Energy proposal—growth forecasts

Forecast	2011	2012	2013	2014	2015	Average growth 2011–15 (per cent)
Maximum demand (MW) [a]	2 181	2 253	2 296	2 390	2 434	2.8
Energy (GWh)	7 793	7 734	7 592	7 478	7 486	–1.0
Customer numbers	630 194	634 296	637 563	641 373	646 457	0.6

(a) Non-coincident maximum demand forecast at the network level, based on a 10 per cent PoE forecast.
Source: United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, November 2009, pp. 193–194.

5.4 Summary of submissions

Several submissions expressed concern about the accuracy of the Victorian DNSPs' forecasts.[2] These concerns included the overestimation in peak demand growth and the underestimation of energy consumption growth when compared to the forecasts made by the Australian Energy Market Operator (AEMO) in its statement of opportunities (SOO). For example, Origin Energy's submission stated:

> ...in principle it is not unrealistic that volumes of energy consumption could drop while peak demand continues to grow… however, the downturn in consumption seems overstated when compared to credible forecasts such as the Australian Energy Market Operator's (AEMO) Electricity Statement of Opportunities (SOO).[3]

Further, the Energy Users Coalition of Victoria (EUCV) noted the:

> ...inconsistency between the DB assessments of future consumption (being negative over the next five years) and the AEMO forecast suggesting there will be a consistent 1.2 per cent annual increase in Victorian electricity consumption.[4]

The submissions also argued that if the AER were to adopt these forecasts, this would result in higher capex requirements spread over fewer sales, leading to higher tariff rates and unit prices for consumers.[5]

Submissions by the Victorian Council of Social Services (VCOSS) and the Consumer Action Law Centre (CALC) recommended the Victorian DNSPs provide a full set of data including the actual and forecast customer numbers and energy consumption for 2006–10 and 2010–15 respectively, to be published by the AER.[6]

Various submissions also noted that the Victorian DNSPs' assumptions in relation to AMI and time of use (TOU) pricing and expressed concern regarding the lack of transparency and the negative impacts on disadvantaged customers, families and small businesses.[7] However, Origin Energy considered that TOU tariffs would have little impact on maximum demand and energy consumption in the forthcoming regulatory control period.[8]

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2 Energy Users Coalition of Victoria (EUCV); Energy Users Association of Australia (EUAA); Consumer Utilities Advocacy Centre (CUAC); Consumer Action Law Centre (CALC); Victorian Council of Social Service (VCOSS); TRUenergy and Origin Energy.

3 Origin Energy, *Submission to the AER re: Victorian DNSP regulatory proposals*, February 2010, p. 2.

4 EUCV, *AER Victorian electricity distribution revenue reset*, Applications from *CitiPower, Powercor, Jemena, SP AusNet and United Energy*, February 2010, p. 81.

5 EUCV, EUAA, CALC and Origin Energy.

6 VCOSS, *Submission to Victorian electricity distribution network service providers' regulatory proposals*, February 2010, pp. 1–2; CALC, *Submission to the Review of initial Distribution Network Service Providers' Proposals for the 2011–15 Regulatory Period*, February 2010, p. 2.

7 Submissions from CUAC, VECCI and the The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria.

8 Origin Energy, pp. 4–5.

5.5 Consultant review

The AER engaged consultant ACIL Tasman to assist and inform its review of the Victorian DNSPs' maximum demand, energy and customer number forecasts.

ACIL Tasman was requested to advise whether the Victorian DNSPs' forecasts are robust, represent good electricity industry practice and therefore produce realistic forecasts of maximum demand, energy and customer numbers. In undertaking the review, ACIL Tasman was asked to comment on a number of details of the various methodologies used, including:

- for maximum demand—the use of top down and bottom up methodologies and the way forecasts prepared by these two means are reconciled, the use of weather normalisation, the treatment of spot loads, whether the forecasts any given DNSP has put forward are consistent at different levels of aggregation
- for energy and customer numbers—key assumptions and inputs, selected base year(s), reasonableness of any scenarios and consistency with historical data.

ACIL Tasman's reports have been published by the AER along with this draft decision.[9]

5.6 Issues and AER considerations

This section outlines the AER's considerations of the following major aspects of the Victorian DNSPs' proposals, including demand, energy and customer numbers as appropriate:

- comparisons of proposals with historic trends and VENCorp data
- assessment of the Victorian DNSPs' proposals against the AER's expectations of a reasonable methodological approach
- NIEIR's methodologies for forecasting demand, energy and customer numbers
- assessment of NIEIR's input assumptions
- adjustments to NIEIR's forecasts for various policy impacts
- DNSPs' methods for producing bottom up forecasts of maximum demand, including comparisons to NIEIR's top down forecasts.

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9 ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of maximum demand forecasts*, Report prepared for the AER, 19 April 2010; ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of electricity sales and customer number forecasts*, Report prepared for the AER, 21 April 2010.

5.6.1 Historic comparisons

Maximum demand

The AER faced some difficulties in comparing maximum demand forecasts across the five Victorian DNSPs due to the forecasts being presented on differing bases. For example, SP AusNet did not provide any network level maximum demand forecasts, or any weather normalised (adjusted) maximum demand forecasts for the forthcoming regulatory control period.[10] Several DNSPs did not specify, or incorrectly specified, their maximum demand forecasts as network coincident or non-coincident forecasts. While some of these differences reflect the specific approaches used by each DNSP, others reflect inconsistencies in the DNSPs' presentation of their own forecasts, which the AER is expecting to resolve by issuing a further regulatory information notice (RIN) following the draft decision.

Summer non-coincident maximum demand forecasts are a key driver of the Victorian DNSPs' reinforcement capex. Table 5.6 presents network level actuals and forecasts which are a sum of the Victorian DNSPs' terminal station non-coincident forecasts.

Table 5.6 Summer maximum demand—actual and forecast average annual growth rate (per cent)

	Previous period (2001–05)	Current period actual (2006–08)	Forecasts (2009–15)
CitiPower	1.0	3.6	2.2
Powercor	3.2	7.1	1.6
Jemena	–0.1	8.0	1.4
SP AusNet	0.4	2.8	2.9
United Energy[a]	1.6	7.4	3.3
DNSPs	1.4	5.7	2.3
VENCorp	1.5	6.0	0.3

(a) United Energy's forecast is 10 per cent PoE, the other Victorian DNSPs' forecasts are 50 per cent PoE.

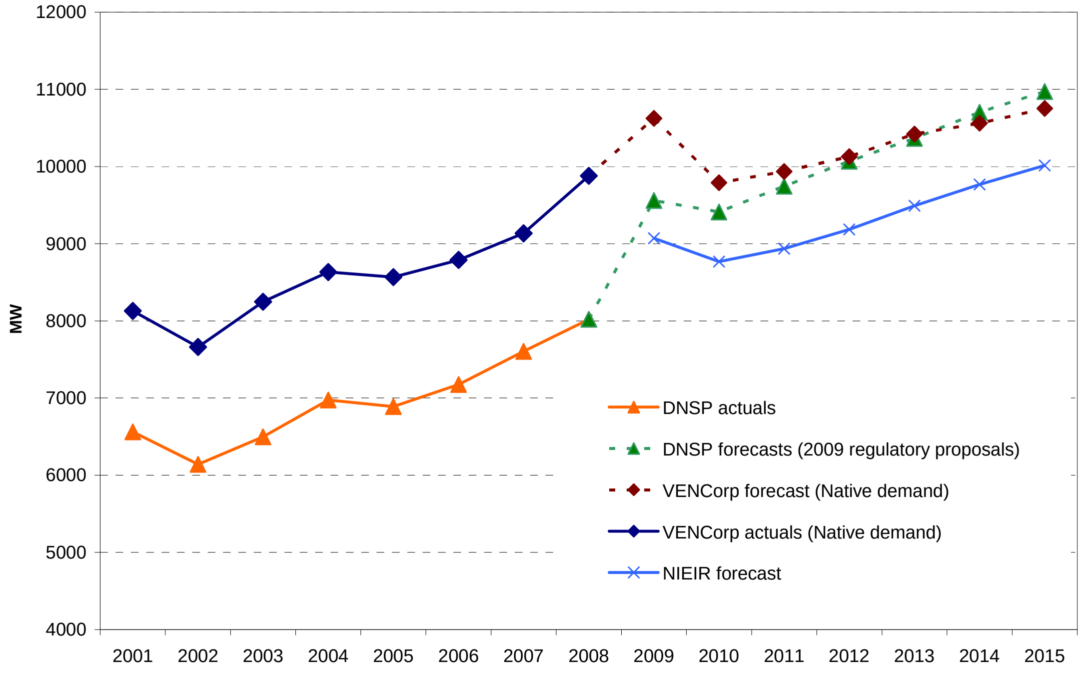
Source: Historical data for the DNSPs are unadjusted system level maximum demand growth taken from their submitted regulatory information notice spreadsheets (DNSPs' RINs). Forecasts are the sum of the DNSPs' non-coincident terminal

[10] The AER notes that SP AusNet's written regulatory proposal included a network level maximum demand forecast, which is reproduced in table 5.4 above. However, SP AusNet's RIN spreadsheets did not include a network level forecast, and the AER was unable to reconcile SP AusNet's written regulatory proposal network level forecast to its ZSS and terminal station level forecasts in the RIN spreadsheets. Accordingly, the AER has disregarded SP AusNet's network level maximum demand forecast for the purposes of its assessment.

station forecasts, within RIN template 6.3, table 10. VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009, tables E1–2 and table 3–1.[11]

Table 5.6 shows that the Victorian DNSPs' forecasts of maximum demand for the forthcoming regulatory control period anticipate a return to more long term maximum demand growth trends from recent high growth years. However, it also shows that the Victorian DNSPs' are forecasting much higher maximum demand growth than VENCorp. Figure 5.1 demonstrates that the difference in growth rates results in the Victorian DNSPs' forecast maximum demand exceeding VENCorp's 2009 Annual Planning Report's (APR) forecast (which includes the transmission network).

Figure 5.1 Actual and forecast maximum demand—DNSPs and VENCorp



Source: Historical data for the DNSPs are unadjusted system level maximum demand growth taken from their submitted regulatory information notice spreadsheets (DNSPs' RINs). Forecasts are the sum of the DNSPs' non-coincident terminal station forecasts, within RIN template 6.3, table 10; ESCV, *Electricity Distribution Price Review 2006–10, Volume 1*, October 2006, p. 132; VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009, tables 3–1 and E1–2.

Data for the current regulatory control period show the impact of recent hot summers in 2008 and 2009. The Victorian DNSPs' forecasts reflect an assumption that air conditioning sales will continue to increase but at a slower rate over the forthcoming regulatory control period as compared to previous periods.

Table 5.7 compares the Victorian DNSPs' forecasts submitted to the Essential Services Commission of Victoria (ESCV) in 2006 with actual demand over 2006 to 2008.

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11 While VENCorp's data is presented on a financial year basis, it is comparable to the Victorian DNSPs' calendar year forecasts, as maximum demand occurs in second half of financial year (for example, 2010–11 is the same as the Victorian DNSPs' 2011 forecasts).

Table 5.7 **Average variance between forecasts to actuals over 2006–08 from Victorian DNSPs 2006 proposal (per cent)**

	Average difference between forecasts and actual MD
CitiPower	19
Powercor	13
Jemena	18
SP AusNet	17
United Energy	27

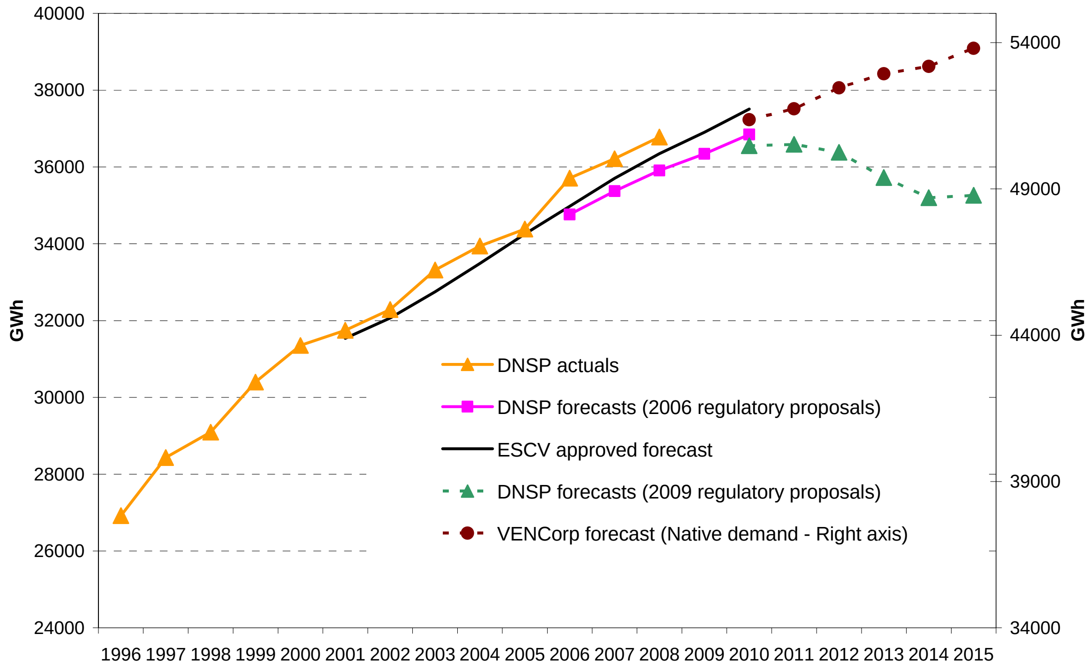
Source: DNSPs' RINs; ESCV, *EDPR 2006–10 (amended), vol. 1*, October 2006, p. 133.

The differences calculated in table 5.7 reflect that, despite recent hot summers, the Victorian DNSPs significantly over forecast maximum demand in their 2006 regulatory proposals to the ESCV. However actual demand may have also been affected by the onset of the global financial crisis (GFC) and related economic slowdown. On average, the Victorian DNSPs over forecasted maximum demand by 24 per cent.

Energy consumption

The Victorian DNSPs’ proposed energy forecasts for the 2011–15 regulatory control period depict a significant reduction from the long term trend, whereby the impact of high electricity prices, energy efficiency policies and low economic growth are predicted to result in energy sales falling by on average 0.8 per cent per annum over the period. Figure 5.2 shows this trend, as well as the divergence between forecast and actual energy sales in previous regulatory control periods.

Figure 5.2 Actual and forecast energy consumption—DNSPs VENCorp and ESCV



Source: DNSPs' RINs template 6.3 table 5; *EDPR 2006–10 (amended), vol. 1*, October 2006, p. 132; VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009, tables 3–3 and E1–1.

The Victorian DNSPs' forecasts are significantly different from those published in VENCorp's 2009 APR, released in April 2009.[12] VENCorp forecasts an average growth in Victorian energy consumption of 0.9 per cent per year over 2011–15 (medium growth, 50 per cent PoE scenario). The Victorian DNSPs' forecasts predict an average decline in energy sales of –0.7 per cent per annum over the same period.

Annual energy consumption increased for each of the Victorian DNSPs over the period 2001–08, in line with energy consumption rates for Victoria. However, while VENCorp forecast a substantial drop in Victorian energy consumption for 2008–09, largely as a result of the economic downturn, VENCorp's energy consumption forecasts are for positive growth over 2010–15. In contrast, the Victorian DNSPs' consumption forecasts exhibit negative growth over the forthcoming regulatory control period.

Table 5.8 provides a comparison of the Victorian DNSPs' and VENCorp's forecast annual growth rates for the forthcoming regulatory control period.

Table 5.8 Forecast annual growth in energy consumption 2011–15 (per cent)

DNSP	2011	2012	2013	2014	2015	Average
CitiPower	0.6	0.3	–1.7	–2.0	0.1	–0.5
Powercor	0.5	–0.5	–1.7	–1.5	–0.2	–0.7
Jemena	–2.2	–1.1	–2.3	–2.0	–0.3	–1.6
SP AusNet	0.1	–0.8	–1.8	–1.5	0.1	–0.8
United Energy	0.5	–0.8	–1.7	–0.8	1.0	–0.4
DNSPs	0.1	–0.5	–1.8	–1.5	0.2	–0.7
VENCorp	0.7	1.4	0.9	0.5	1.2	0.9

Source: DNSPs' RINs, template 6.3 table 5; VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009.

The Victorian DNSPs' forecast of declines in energy consumption for the forthcoming regulatory control period is largely driven by assumptions about the impact of various Government policies, particularly AMI (time of use tariffs), CPRS and energy efficiency standards for lighting and other appliances. However, the AER notes VENCorp's 2009 APR forecasts:

- contain the same list of policy adjustments used by NIEIR

12 VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009, p. 69.

- were conducted at the height of the GFC and therefore are based on a different set of economic growth assumptions (as discussed in section 5.6.4).

Table 5.9 presents the Victorian DNSPs' forecasts as compared to different periods of recent history. The second column of table 5.9 also reflects the estimates of consumption used by the Victorian DNSPs for 2009 which is the first year in the time series to exhibit a decline from previous years.

Table 5.9 Consumption per residential customer—average annual growth (per cent)

	2005–08	2005–09	2010–15
CitiPower	0.34	0.22	–3.04
Powercor	0.83	0.66	–5.05
Jemena	1.35	0.64	–3.09
SP AusNet	1.43	0.41	–3.59
United Energy	1.70	0.75	–3.08

Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 70, 85, 97, 110, 124 (data from NIEIR Electricity sales and customer numbers report table 7.1 and 7.2, November 2009).

Customer numbers

Table 5.10 sets out the Victorian DNSPs' actual and forecast customer numbers. Overall the Victorian DNSPs' forecasts appear to be growing in line with recent historical trends. CitiPower and Powercor are forecasting faster customer growth for 2011–12, slowing in the latter years of the period. United Energy's customer number growth is the lowest out of the Victorian DNSPs', reflecting the established nature of dwellings and businesses in United Energy's region.

Table 5.10 AER analysis of customer numbers—average annual growth (per cent)

DNSP	Previous period (2001–05)	Current period (2006–08)	Forecasts (2009–15)
CitiPower	1.1	1.7	1.5
Powercor	2.4	1.8	1.6
Jemena	2.5	0.8	1.4
SP AusNet	1.1	0.8	1.6
United Energy	2.1	1.6	0.7

Source: DNSPs' RINs, template 6.3 table 1.

The AER notes that while actual customer numbers have steadily increased since 2001, with the exception of CitiPower's network, annual average growth rates for customer numbers have decreased marginally during the current regulatory control period. The projected growth rates in customer numbers for the forthcoming regulatory control period are relatively unchanged from the current regulatory control period to date. The exception is Jemena which has forecast that annual growth in customer numbers will average 1.4 per cent, up from 0.8 per cent for the current regulatory control period to date.

Table 5.11 AER analysis of 2006 forecasts—variance from actuals 2006–08 (per cent)

	Variance from actual
CitiPower	–3.2
Powercor	–3.5
Jemena	–2.0
SP AusNet	0.3
United Energy	0.9

Source: DNSPs' RINs; DNSPs 2006–10 regulatory proposals, 20 October 2004, p. 125.

Table 5.11 illustrates that there is no systematic variance between the Victorian DNSPs' forecasts of customer numbers proposed to the ESCV in 2006 and actual outcomes for the years 2006 to 2008.

AER considerations

In the context of concerns expressed by stakeholders, the AER notes that actual maximum demands have turned out to be much lower than the forecasts proposed by the Victorian DNSPs to the ESCV at the time of the last review, even though demands in recent years have reflected particularly hot summers. However, the AER notes that the Victorian DNSPs' forecasts for the forthcoming regulatory control period appear to be generally consistent with historic trends, but higher than VENCorp's most recent forecasts for Victoria. The forecasts of customer numbers also appear to be in line with historic trends.

The data presented in figure 5.2 above is consistent with the perverse incentives of weighted average price cap form of control where the DNSPs are able to achieve significant windfall gains by under forecasting energy consumption at the time of each price review. The data underlying figure 5.2 shows that over 2001–08 (that is, where actual energy sales and approved forecasts are available) the Victorian DNSPs have distributed 3,246 GWh more than the forecasts ultimately relied upon by the ESCV. The AER estimates that these additional sales have resulted in a $144 million or 1.2 per cent increase in revenues for the Victorian DNSPs over these nine years.[13] The AER expects the incentive to understate energy sales forecasts to have affected the Victorian DNSPs' proposals in the same way as those presented to the ESCV at the last review.

[13] This reflects the Victorian DNSPs' combined revenues (excluding S factor payments) per GWh distributed over 2001–08, multiplied by the incremental GWh above the forecasts determined by the ESCV for those years.

While the AER acknowledges that growth in energy consumption has slowed in recent years, figure 5.2 and table 5.10 demonstrate that the Victorian DNSPs now predict a massive change in customer behaviour from 2009 (the first year of estimate/ forecast data) such that total energy consumption would actually decline, in spite of continued growth in maximum demand and customer numbers. The AER expects that this is due to the Victorian DNSPs overstating the impact of certain policy changes. This is supported by the fact that VENCorp has forecast energy consumption to increase in the presence of the same policies, but also on the basis of economic growth forecasts that reflected pessimism at the time of the 2009 APR. The AER considers that VENCorp and AEMO's forecasts are a valid cross check on the reasonableness of the Victorian DNSPs' forecasts. This was also reflected in stakeholders' submissions as noted above.

5.6.2 Best practice methodology assessment

This section outlines the AER's assessment of the methodologies employed by the Victorian DNSPs and NIEIR in terms of key features deemed to be best practice by the AER and its consultant. The presence of such methodological features (as explained for each below) is an important factor in determining whether the Victorian DNSPs have, pursuant to clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER, produced forecasts that reasonably reflect a realistic expectation of the demand forecast and cost inputs to achieve the operating expenditure objectives and capital expenditure objectives, respectively.

ACIL Tasman considered the following features necessary to produce best practice maximum demand, energy and customer number forecasts:

- Accuracy and unbiasedness—careful management of data (removal of outliers, data normalisation) and forecasting model construction (choosing a parsimonious model based on sound theoretical grounds that closely fits the sample data). [14]

- Transparency and repeatability—as evidenced by good documentation, including documentation of the use of judgment, which ensures consistency and minimises subjectivity in forecasts.

- Incorporation of key drivers—including economic growth, population growth, growth in the number of households, temperature and weather related data (where appropriate), and growth in the numbers of air conditioning and heating systems.

- Model validation and testing—including assessment of statistical significance of explanatory variables, goodness of fit, in-sample forecasting performance of the model against actual data, diagnostic checking of the old models, out of sample forecast performance. [15]

ACIL Tasman also considered the following elements to be relevant to maximum demand forecasting:

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[14] A model with fewer rather than a larger number of variables.

[15] ACIL Tasman, *Review of maximum demand forecasts*, pp. 2–11; ACIL Tasman, *Review of electricity sales and customer number forecasts*, pp. 2–4.

- Spatial (bottom up) forecasts validated by independent system level (top down) forecasts—best practice forecasting requires these forecasts to be prepared independently of each other. The impact of macroeconomic, demographic and weather trends are better able to be identified and forecast in system level data, whereas spatial forecasts are needed to capture underlying characteristics of areas on the network. Generally, ACIL Tasman considered spatial forecasts should be constrained to system level forecasts.[16]

- Weather normalisation—correcting historical loads for abnormal weather conditions is an important aspect of demand forecasting. Long time-series weather and demand data are required to establish a relationship between the two and conduct weather correction. Weather correction is relevant to both system and spatial level forecasts, and ACIL Tasman considered that system level weather correction processes are more sophisticated and robust.[17]

- Adjusting for temporary transfers—spatial data must be adjusted for historical spot loads arising from peak load sharing and maintenance, before historical trends are determined.[18]

- Adjusting for discrete block loads—large new developments (for example, shopping centres, housing developments) should be incorporated into the forecasts, taking account of the probability that each development might not proceed. Only block loads exceeding a certain size threshold should be included in the forecasts, to avoid potential double counting, as historical demands incorporate block loads.[19]

- Incorporation of maturity profile of service area in spatial time series—recognising the phase of growth of each zone substation, taking account of the typical lifecycle of a zone substation, depending on its age, helps to inform likely future growth rates.[20]

With respect to energy forecasting, ACIL Tasman also considered it important to incorporate anticipated impacts of public policies which are introduced during the regulatory control period. Policy impacts can be either estimated on the basis of results from similar current policies, policies in other jurisdictions or by considering the outcomes of trials. However, ACIL Tasman points out that all methods of accounting for policy impacts require assumptions about customer behaviour or jurisdictional/situational similarities and differences.[21]

In addition to the features identified by ACIL Tasman, the AER considers that accuracy and consistency of forecasts at different levels of aggregation also affects the overall reasonableness of the forecasts, as accuracy at the total level may mask errors at lower levels (for example, at each zone substation or tariff class) that cancel each

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16 ACIL Tasman, *Review of maximum demand forecasts*, pp. 2–3.
17 ibid., p. 4–7.
18 ibid., p. 7.
19 ibid., pp. 7–8.
20 ibid., pp. 8–9.
21 ACIL Tasman, *Review of electricity sales and customer number forecasts*, pp. 2–3.

other out. The AER also considers that the use of the most recent input information is necessary in developing reasonable expectations of future conditions.

Summary of comparisons

The AER has reviewed the Victorian DNSPs' maximum demand forecasting methodologies in light of each of the elements of good methodological practice outlined above, including as identified by ACIL Tasman in its reports. Table 5.12 summarises the AER's observations about the methodologies used by NIEIR and the Victorian DNSPs to forecast maximum demand for the forthcoming regulatory control period. Observations regarding energy and customer numbers are also listed, however the AER's full assessment of NIEIR's forecasts is outlined in the next section.

Table 5.12 Victorian DNSPs' and NIEIR's forecasting methodologies compared with elements of good methodological practice

Element of good methodological practice	NIEIR[a]	CitiPower	Jemena	Powercor	SP AusNet	United Energy
Validation of spatial and global forecasts (MD)	N/A	No validation or reconciliation undertaken.	Reconciles to NIEIR growth rates only.	Comparison undertaken, with adjustments performed if deemed necessary.	Reconciles to NIEIR's starting point, forecasts revised to bring closer to NIEIR's.	Reconciles to NIEIR's growth rates, however data indicates forecasts are decoupling
Weather normalisation (MD)	PeakSim accounts for half hourly load and temperature data for the previous 13 years.	Ratio based approach, taking account of the average daily ambient temperature, using relationship between temperature and MD derived from long run temperature data determined by VENCorp.	Uses polynomial curve of best fit to determine relationship between MD and daily average temperature for most recent year, and generates an adjusted starting point for the forecast.	No explicit process is applied. Assumes the last five years of data sufficiently reflects a 50 PoE and associated MD.	No explicit process is applied. However, in some zone substations, SP AusNet has revised last MD down arbitrarily to account for 2009 extreme weather.	Weighted average approach, linear relationship is derived from daily maximum and minimum temperatures (80/20 weighting).
Adjusting for load transfers (MD)	N/A—this is not important at the system level	Carried out after weather normalisation for feeder transfers between zone substations.	Future known load transfers between feeders are incorporated into the forecast. Historical load transfers are not removed from actuals.	Judgement based approach, no adjustments for load transfers demonstrated.	No adjustments for expected load transfers in forecasts or historicals, although planner 'bore it in mind' in determining growth rates.	Adjustment made for loads transferred between zone substations occurring since most recent MD observed.
Incorporation of spot loads (MD)	Incorporated above a threshold level for some DNSPs, not as important at the system level.	Anticipated spot load connections >100kVA incorporated, with a probability weighting of 0.5. Based on	Known loads >100kVA added to forecast separately, assume residential and commercial loads taken	Judgement based approach, no adjustments for spot loads demonstrated.	No formal adjustment for known spot loads.	Known new loads >0.5MW are incorporated, based on United Energy's understanding of the

		information from connection inquiries and local government	up over time.			area.
Consideration of maturity profile of zone substation (MD)	N/A	Future growth expectations for local area incorporated into annual growth on each zone substation.	Organic growth rates assumed based on local knowledge, judgment and historical trends	Judgement based approach incorporates growth expectations based on knowledge of zone substation age profile.	Regional planners use judgment to determine the growth rates, based on local knowledge.	Expectations of future growth and knowledge of recent growth in each area are accounted for in the zone substation growth rates.
Accuracy and unbiasedness	Historical performance is reasonable, however is dependent on input assumptions and post model adjustments	MD: Level of judgment applied creates potential for bias. The lack of reconciliation to independent system forecasts creates potential bias. Energy/customer numbers: see NIEIR.	MD: Better documented process results in lower potential for bias than other DNSPs. Energy/customer numbers: see NIEIR.	MD: Level of judgment applied creates potential for bias. Energy/customer numbers: see NIEIR.	MD: High level of judgment applied leaves process open to bias and error. Energy: Assumptions based on judgment and selected group of studies leaves outcome open to bias. Customer numbers: see NIEIR.	MD: Forecasts are adjusted differently for each zone substation such that system growth rates are consistent—bias towards growth in zone substations on the cusp of capex is likely. Energy/customer numbers: see NIEIR.
Transparency and repeatability	Not transparent. ‘Base model’ not well described and not provided on basis of propriety information. Model description obtained from external sources (VENCorp). Assumptions and	MD: Heavy reliance on the judgment of planners and forecasters. No documentation of forecasting process, therefore not repeatable. Energy/customer numbers: see NIEIR.	MD: Load forecasting manual provided—process is well documented and likely to be repeatable Energy/customer numbers: see NIEIR.	MD: Heavy reliance on the judgment of planners and forecasters. No documentation of forecasting process, therefore not repeatable. Energy/customer numbers: see NIEIR.	MD: Documentation of spatial forecasting process only provided late in the AER's review process. Reliance on regional planner judgment challenges repeatability and transparency. Energy: reasonable documentation and	MD: No documentation of United Energy's spatial processes was provided. Use of judgment at the network planner level is not transparent. Energy/customer numbers: see NIEIR.

	model adjustments generally transparent, but subject to some inconsistencies and transcription errors in documentation.				information provided, likely to be repeatable. Customer numbers: see NIEIR.	
Incorporation of key drivers	MD: Accounts for population growth, economic growth, air conditioning sales (MD), hot water trends (energy) and government policies.	MD: NIEIR's forecast accounts for key drivers —see comment on reconciliation process Energy/customer numbers: see NIEIR.	MD: NIEIR's forecast accounts for key drivers —see comment on reconciliation process Energy/customer numbers: see NIEIR.	MD: NIEIR's forecast accounts for key drivers —see comment on reconciliation process Energy/customer numbers: see NIEIR.	MD: NIEIR's forecast accounts for key drivers —see comment on reconciliation process Energy/customer numbers: see NIEIR.	MD: NIEIR's forecast accounts for key drivers —see comment on reconciliation process Energy/customer numbers: see NIEIR.
Model validation and testing	NIEIR carries out a range of tests and model validation exercises	MD: No information provided on data testing. Energy/customer numbers: see NIEIR.	MD: Performs econometric testing of its polynomial approach to weather normalisation. Energy/customer numbers: see NIEIR.	MD: No information provided on data testing. Energy/customer numbers: see NIEIR.	MD: No information provided on data testing. Energy/ customer numbers: see NIEIR.	MD: No information provided on data testing. Energy/customer numbers: see NIEIR.
Level of disaggregation	Forecasts are considered by customer groupings: residential, commercial and industrial.	MD: Approach does not disaggregate the forecasts between customer types or temperature sensitive/insensitive loads. Energy/customer	MD: Feeder level forecasts not disaggregated into load by customer type, however some customer specific load change information is incorporated, use of judgment to determine	MD: Feeder level forecasts enable consideration of feeder classifications, however no evidence of assumptions relating to customer types was provided.	MD: Regional planners consider customer profile in determining growth rates, however process is not formal and is unclear. Energy: Tariff class assumptions allow	MD: Simplistic reconciliation to NIEIR's forecasts masks all disaggregation applied by NIEIR. Energy/customer numbers: see NIEIR.

		numbers: see NIEIR.	outcome for MD. Energy/customer numbers: see NIEIR.	Energy/customer numbers: see NIEIR.	appropriate disaggregation. Customer numbers: see NIEIR.	
Use of recent input information	Incorporates economic growth forecasts from November 2009, however some government policy changes have subsequently occurred.	MD: Spatial forecasts prepared in 2009 for regulatory proposal. Other input information relies on reconciliation with NIEIR's forecasts. Energy/customer numbers: see NIEIR.	MD: Spatial forecasts prepared in 2009 for regulatory proposal. Other input information relies on reconciliation with NIEIR's forecasts. Energy/customer numbers: see NIEIR.	MD: Spatial forecasts prepared in 2009 for regulatory proposal. Other input information relies on reconciliation with NIEIR's forecasts. Energy/customer numbers: see NIEIR.	MD: Spatial forecasts prepared in 2009 for regulatory proposal. Other input information relies on reconciliation with NIEIR's forecasts. Energy: Reflects policy expectations at the time of proposal. Customer numbers: see NIEIR.	MD: Spatial forecasts prepared in 2009 for regulatory proposal. Other input information relies on reconciliation with NIEIR's forecasts. Energy/customer numbers: see NIEIR.

(a) NIEIR's methodology develops system level forecasts which are then disaggregated down to terminal station forecasts, while the Victorian DNSPs' methodologies produce spatial forecasts at the feeder or zone substation which are then aggregated to either terminal station or system level for comparison with NIEIR's forecasts.

The AER's and ACIL Tasman's analysis has found that each of the Victorian DNSPs incorporate some elements of best practice forecasting into their spatial maximum demand forecasts (and SP AusNet into its approach to energy forecast adjustments), however there are serious flaws and gaps in each DNSP's approach. As noted in section 5.6.5 below, the main flaw identified in the Victorian DNSPs' methods is the lack of appropriate reconciliation to NIEIR's top down forecasts. This undermines the reasonableness of the forecasts underlying their capex proposals as NIEIR's forecasts are independently prepared and incorporate drivers such as economic growth and temperature sensitivity not adequately taken into account at the spatial level.

Moreover, while NIEIR's forecasting methodologies appear to contain the elements of good forecasting set out above, its forecasting model is insufficiently transparent. The Victorian DNSPs were unable to provide the AER with NIEIR's modelling calculations on the basis that this information is proprietary.[22] In addition, the information provided to the AER by the Victorian DNSPs was insufficient to form a judgment on whether NIEIR's methods are reasonable or not, and the AER and its consultant were referred to a description of NIEIR's model contained in a report released by VENCorp.[23] As the Victorian DNSPs were unable to provide the AER information on NIEIR's methodologies it is apparent they do not understand NIEIR's forecasts, and have engaged NIEIR on the basis of its past performance and the fact that it provides advice to 'most transmission and distribution service providers in the NEM including VENCorp and AEMO'.[24]

In other respects, the AER notes that certain input and policy assumptions, while current at the time forecasts were developed, have now become outdated. This is discussed in detail in section 5.6.4 below.

5.6.3 NIEIR forecasting methodologies

The following sections summarise the AER's findings with respect to NIEIR's approach to developing top down demand forecasts for the Victorian DNSPs, as well as its energy and customer number forecasts which formed part of the Victorian DNSPs' proposals.

Maximum demand

NIEIR's approach to forecasting system level maximum demand involves dividing demand into that which is temperature insensitive (driven by factors such as economic conditions, relevant policies and appliance take up) and temperature sensitive demand (which is principally driven by weather and related effects). NIEIR then sums both temperature insensitive and sensitive demands, before adjusting for other policy impacts.[25]

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22 For example, see SP AusNet, *SPA Response to additional information request 21122009*, p. 3.

23 VENCorp, *2009 Electricity Forecast Report 2009,* available at http://www.aemo.com.au/planning/v400–0016.pdf

24 CitiPower, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 32.

25 ACIL Tasman, *Review of maximum demand forecasts*, p. 13.

NIEIR uses a model known as 'PeakSim' to produce maximum demand forecasts for the Victorian DNSPs, as well as producing forecasts for VENCorp (now AEMO).[26] PeakSim establishes total demand as a function of:

- temperature insensitive demand
- temperature
- calendar effects, outliers and holidays.[27]

PeakSim takes into account historical temperature insensitive demand, half hourly interval ambient temperatures, and day types, to produce a model of the intra-day relationship between temperature and electricity demand. Simulations of temperature and demand are then produced, which maintain the relationship while accounting for urban and global warming effects on recent and future temperature trends.[28]

The synthetic distributions of demand and temperature are produced using 'boot-strapping' methods that preserve the relationship between temperature and demand while allowing for the effects of urban and global warming on both recent and future temperature trends.

PeakSim's temperature function takes account of the ambient temperature in each half hourly interval, as well as the daily maximum and minimum temperatures. Together, these are used to estimate the temperature sensitivity of demand in the region in question, and this coefficient is then projected forward at the same growth rates as temperature sensitive energy consumption, thus taking account of changes in the take up of weather sensitive appliances, in particular air conditioners. Estimated coefficients associated with the calendar effects, outliers and holidays are similarly increased in line with growth in temperature insensitive energy consumption.[29]

Air conditioning sales are a key driver of PeakSim's forecasts, which are monitored by NIEIR and input into the model.[30] Air conditioning sales drive the temperature sensitive proportion of maximum demand. NIEIR's assumptions about economic growth, government energy policies and forecast energy prices are also input into PeakSim. The AER's consideration of NIEIR's input assumptions is provided in section 5.6.4 of this chapter.

Consultant review

ACIL Tasman noted NIEIR's weather sampling is limited to 13 years of data, and it expected a longer time series of demand and temperatures would improve the forecasts of weather, in particular given the most recent high number of hot summers and weather conditions. That said, ACIL Tasman acknowledged the difficulty in acquiring such longer time series of weather and demand data.[31]

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26 For example, see NIEIR, *Maximum demand forecasts for SP AusNet*, p. 34.
27 ACIL Tasman, *Review of maximum demand forecasts*, p. 15.
28 ibid., pp. 15–16.
29 ibid., pp. 16–17.
30 For example see NIEIR, *Maximum demand forecasts for SP AusNet*, p. 34.
31 ACIL Tasman, *Review of maximum demand forecasts*, p. 17.

ACIL Tasman noted NIEIR's PeakSim model was introduced in response to findings that its previous approach tended to over forecast summer maximum demand in Victoria. AEMO's backcasting analysis of PeakSim demonstrates the methodology is substantially more accurate than its predecessor model.[32] ACIL Tasman noted that the model validation and testing processes NIEIR applied to its Victorian forecast model (as noted by AEMO) are appropriate, however ACIL Tasman also considered that the same level of testing and validation should be applied to the models used to generate each DNSP's maximum demand forecast.[33]

ACIL Tasman considered NIEIR's use of a bootstrapping technique to generate synthetic demand and weather data is appropriate, and noted that applying weight to the latter years of data to account for recent climate trends (including general warming and urban infill) would tend to increase forecasts however is not unreasonable.

ACIL Tasman stated that while a lack of detailed information made it difficult to draw concrete conclusions on NIEIR's maximum demand forecasting methodology, it has a number of features that are a necessary and desirable part of any demand forecasting process. ACIL Tasman stated that it considers NIEIR's general approach to be sound.[34]

AER considerations

NIEIR's approach to forecasting maximum demand for the Victorian DNSPs is consistent with its approach to forecasting for VENCorp for the 2009 Statement of Opportunities. As noted by ACIL Tasman, VENCorp's backcasting analysis of PeakSim indicates that the model is reasonably accurate, showing a good degree of correlation between simulated and actual maximum demands, and producing a root mean squared error of 1.69 per cent. VENCorp notes that the model is reviewed and improved each year, which the AER considers reflects good forecasting practice.[35]

On 17 February 2010, SP AusNet provided the AER a report from NEMMCO to the AEMC's Reliability Panel, summarising VENCorp's backcasting analysis for the 2008 SOO forecasts where a root mean squared error of 2.59 per cent was measured.[36]

On 28 April 2010, CitiPower and Powercor submitted further analysis of NIEIR's energy forecasting methodology prepared by Frontier Economics.[37] This information was received too late for it to be considered as part of this draft decision, however it will be considered by the AER in making its final decision in October 2010.

As noted above, NIEIR's approach to generating the simulated temperatures and demand within PeakSim places more weight on recent years of temperature data, which include some effects described as global warming. NIEIR considered this was more relevant to the maximum demand forecast.[38] ACIL Tasman considered that any evidence of a global warming trend is likely to be related to either climatic conditions

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32 ibid., p. 18.
33 ibid., pp. 12–19.
34 ibid., p. 19.
35 AEMO, *2009 Electricity Statement of opportunities*, Appendix C, p. C18.
36 NEMMCO, *Report to the Reliability Panel on Demand Forecasts*, 30 October 2008, p. 13.
37 CitiPower and Powercor, email to AER staff, 28 April 2010.
38 ACIL Tasman, *Review of maximum demand forecasts*, p. 15.

(anthropogenic and non-anthropogenic) or due to a heat island effect, both of which are reasonably long term and slow moving. ACIL Tasman considered that global warming trends would not be expected to have a statistically significant impact over the 13 years of temperature data used within NIEIR's model, let alone a material impact on the forecast outputs, and recommended that the AER seek further information from NIEIR on the temperature trend coefficients and calculated MW impact.[39] The AER notes that the impact of NIEIR's assumed global warming trend on the Victorian DNSPs' maximum demand forecasts is likely to be immaterial when compared to the impacts of air conditioning, economic growth and government policies. The AER considers that, while the incorporation of warming temperature trends into a model of such short time frames is questionable, as highlighted by ACIL Tasman, the overall accuracy of NIEIR's base forecasting model, as discussed above, indicates that the impact of this effect is likely to be immaterial in considering the maximum demand forecasts. The AER's broader consideration of the impact of climate change on the Victorian DNSPs' operations is provided in appendix L, including a discussion on the AECOM reports submitted by the Victorian DNSPs as part of their regulatory proposals.

In relation to the weather series data used in NIEIR's forecasting model, the AER agrees with ACIL Tasman's view that a longer time series of data may produce a more robust forecast. However, the AER also acknowledges that longer historic time series are not available for all Victorian DNSPs. The AER expects that over time, improved data collection by the Victorian DNSPs will improve the forecasts.

Section 5.6.2 above sets out NIEIR's maximum demand forecasting approach with regard to elements of best practice forecasting. As stated above, the AER was unable to review NIEIR's forecasting model. Accordingly, the AER's understanding of this model is limited to descriptions that were provided with the Victorian DNSPs' proposals and to the subsequent discussions it had with NIEIR.

On the basis of the limited information available regarding NIEIR's overall methodology, and on the advice of ACIL Tasman, the AER considers that, on balance, NIEIR's general method appears to be reasonable. This consideration has been taken into account by the AER when assessing whether the Victorian DNSPs' forecasts are a realistic expectation of demand under clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER.

Energy

In generating the Victorian DNSPs' energy forecasts, NIEIR applied a methodology similar to its approach to forecasting Victorian energy consumption for VENCorp for the 2009 APR.[40]

NIEIR's methodology for forecasting energy consumption can be broken down into a number of steps:

- Disaggregate total historical sales into residential and business customer sales, using the tariff class data provided by each DNSP.

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39 ibid., pp. 16–17.

40 VENCorp, *Victorian Annual Planning Report 2009*, 16 July 2009,

- Forecast residential and business sales separately:

  - For business sales, NIEIR maps the economy of each DNSP's region by firstly taking its Victorian gross state product (GSP) forecast (based on industry output, major investment projects, dwelling stock and population growth) and disaggregating it into statistical subdivisions and local government areas across Victoria by industry type. For every large customer (>160MWh/annum) NIEIR determines an Australian Securities and Investments Commission (ASIC) industry coding, to which it applies its growth assumptions, which are informed by energy demand data taken from the Australian Bureau of Agricultural and Resource Economics (ABARE). Medium business customers' energy consumption is based on sample data of Powercor's region (determining an average make-up of medium businesses in Victoria), projected using NIEIR's assumptions.

  - For residential sales, NIEIR disaggregates the forecast into hot water, general sales to new customers and existing customers. For existing customers, NIEIR's model projects energy consumption as a function of real income per capita, real and relative energy prices (expected to remain as status quo except for the CPRS–5 assumption) and weather. For new customers, NIEIR's base model assumes no change in the average residential energy use; it simply forecasts the number of new dwellings expected and applies the current average residential usage. For hot water consumption, NIEIR forecasts a reduction in sales each year to account for government policies to phase out electric resistance hot water systems, based on assumptions about the failure rates of existing hot water systems in Victoria.

- Public lighting sales are forecast based on NIEIR's infrastructure construction forecasts and information provided by the Victorian DNSPs on the implementation of energy efficiency light globes.

- Apply assumptions about government policies and adjust initial forecasts, before aggregating all sales classes for each DNSP. [41]

NIEIR applies a weather normalisation methodology to remove the effect of abnormal weather years and enable energy consumption to be compared across years and forecast based on historical data.[42] Energy consumption forecasts are driven by the number of heating and cooling degree days expected to occur in each year, which are based on the historical relationship between heating, cooling and average daily temperature.[43] NIEIR uses 50 years of historical records of total heating and cooling degree days for each month, and assumes a linear trend in heating and cooling days in any given month. NIEIR stated that the linear trend is used due to rising temperatures over the data period, which it attributes to localised and global warming.[44]

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41 ACIL Tasman, *Review of electricity sales and customer number forecasts*, pp. 5–9.
42 For example, see NIEIR, *Maximum demand forecasts for SP AusNet*, p. 38.
43 ACIL Tasman, *Review of electricity sales and customer number forecasts*, p. 19–20; For example see NIEIR, *Electricity sales and customer number forecasts for SP AusNet*, p. 38.
44 ibid.

NIEIR's input assumptions are discussed separately in section 5.6.4.

Consultant review

ACIL Tasman noted the general lack of transparency in the information made available by NIEIR and the Victorian DNSPs on the models used in energy forecasting.[45]

ACIL Tasman noted that in forecasting business customer sales, when determining the average energy intensity of each industry group, NIEIR's model did not always produce logical or statistically significant outcomes. ACIL Tasman noted that in those cases, NIEIR replaced its forecasts for these industry groupings with forecasts prepared by ABARE, however it did not disclose which industry group forecasts were substituted in this process.[46] ACIL Tasman noted that NIEIR's industry group modelling was performed on a small subset of information, and extrapolated across all the Victorian DNSPs, assuming that the small and medium size business industry group structure of each DNSP would mirror that of Powercor (where NIEIR's sample testing was undertaken). ACIL Tasman noted further sampling of industry groups may produce a more accurate forecast, and that the information provided to it did not enable it to reach a conclusion on the appropriateness of NIEIR's disaggregated approach.[47]

In reviewing NIEIR's forecast of average energy consumption by residential customers for CitiPower, ACIL Tasman noted that NIEIR's forecasts exhibit no clear trend in the energy intensity of dwellings, as NIEIR assumed that new dwellings would have the same energy intensity of existing dwellings. This is despite the fact that recent data demonstrates declines in the average energy intensity of dwellings in CitiPower's region over 2003–06.[48] ACIL Tasman noted that the decline in average energy use of dwellings by vintage was not evident in the historical data for the other DNSPs. While ACIL Tasman considered this effect was likely to mean NIEIR's energy forecasts for CitiPower were biased upwards by a small factor, it noted that NIEIR faced some data issues which prevented it from taking this factor into account in CitiPower's forecasts.

NIEIR's reports provided a summary of post model adjustments for hot water sales forecasts (based on Government policies) which ACIL Tasman reviewed and found to be inconsistent with NIEIR's description of its policy assumptions.[49] However, upon further questioning, NIEIR revealed that as the hot water sales forecast is actually developed as part of its base energy forecast model (and therefore not a post-model adjustment), the numbers provided for hot water in the reports should be disregarded. ACIL Tasman considered that NIEIR's approach to forecasting hot water sales appeared reasonable and in line with recent historical trends (based on the information

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45 ACIL Tasman, *Review of electricity sales and customer number forecasts*, p. 5–6.
46 ibid., p. 7.
47 ibid., pp. 7–8.
48 ibid., pp.65–66.
49 For example, see NIEIR, *Electricity sales and customer number forecasts for SP AusNet*, p. 49, tables 6.2, 6.3.

provided), however was unable to assess the assumed impact of government hot water policies.[50]

AER considerations

The AER notes ACIL Tasman's comments about NIEIR's industry group forecasts being based on a small subset of information, and that in certain cases the model failed to produce rational outcomes for certain industry groups. However, as noted by NIEIR, its reasons for adopting an industry based approach to forecasting energy are that it enables a more rigorous analysis, capturing the implications for energy sales of declining industries such as motor vehicle production, and growing industries such as entertainment.[51] The AER considers that this approach is likely to produce forecasts that are as accurate, if not more accurate, than forecasts simply based on total state or regional economic growth, and enables sophisticated mapping of Victorian business sales.

The AER agrees that further industry sampling in each DNSP's region would improve forecasting accuracy, however it considers that the costs of this additional sampling may outweigh the value it provides to the forecast overall. The AER notes that the approach to aggregating the results of industry sampling in Powercor's region to the other DNSPs' regions affects only the energy consumption forecasts of small business customers consuming less that 160 MWh per annum. As such, the AER considers that this approach is unlikely to give rise to material inaccuracies.

The AER also considers NIEIR's approach to disaggregating energy forecasts into business, residential and hot water sales forecasts is reasonable, and is likely to produce a good reflection of the energy consumption profile of Victorian customers. The AER considers NIEIR's approach to forecasting hot water sales, as it was described, is appropriate. However, the AER has not been able to review the assumed impact of hot water policies on the sales forecast as these were not explicitly quantified. The AER's consideration of NIEIR's policy assumptions is outlined in section 5.6.5 below.

The AER considers that NIEIR's assumption that the average energy intensity of dwellings does not vary with dwelling age (that is, new houses use the same amount of energy as existing houses) may result in a slight bias upwards in the energy forecast for CitiPower. However, the AER considers that the impact of this effect is likely to be minimal, and is in any case dwarfed by the effect of policy assumptions, which are discussed in section 5.6.4.

The AER's assessment of NIEIR's approach to forecasting energy, considering the elements of good methodological practice summarised in table 5.12, found that NIEIR's approach generally exhibits elements of good forecasting.

However, the AER echoes ACIL Tasman's comments about a lack of transparency in the information provided by NIEIR on its energy forecasting methodology. Based on the information provided and on ACIL Tasman's advice, the AER considers that NIEIR's underlying methodology for forecasting energy consumption appears to be

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50 ACIL Tasman, *Review of electricity sales and customer number forecasts*, pp. 38–40.

51 For example see NIEIR, *Electricity sales and customer number forecasts for SP AusNet*, p. 34.

reasonable, which has informed the AER's consideration on whether the Victorian DNSPs' forecasts are a realistic expectation of demand under clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER. The AER's consideration of NIEIR's input assumptions is provided in section 5.6.4.

Customer numbers

NIEIR provided only a limited summary of its approach to forecasting customer numbers.

Residential customer forecasts are driven by NIEIR's dwelling stock projections, which are an output of its construction industry models. Different types of construction (residential, non residential, and engineering) are considered separately. For residential construction, NIEIR's model accounts for building approvals, commencements and completions by dwelling type. NIEIR takes its Victorian forecasts of dwelling stocks and disaggregates them into statistical subdivision and local government area forecasts, to be then aggregated by DNSP. NIEIR stated that population growth is a key driver of residential customer numbers.[52]

For non residential customers, as well as the construction industry forecast, customer numbers are derived from the historical energy consumption data for each customer class, and therefore average usage per customer, as well as historical customer growth data.[53]

Consultant review

Due to the limited information provided on NIEIR's customer number forecasting methodology, ACIL Tasman did not make any assessments of the methodology applied. Rather, ACIL Tasman focused on comparing the customer number forecasts to recent historical data for each DNSP. ACIL Tasman found that all of the Victorian DNSPs' customer number forecasts are largely consistent with historical trends over 2005–09.

For CitiPower, ACIL Tasman noted NIEIR's annual population growth forecast was approximately half its forecast of annual growth in dwelling stock. CitiPower commented on this assumption, and indicated that it was likely to be a typographical error in NIEIR's report.[54] However, CitiPower stated the dwelling forecast is correct.

AER considerations

As noted by ACIL Tasman, a very limited summary of NIEIR's approach to forecasting customer numbers was provided by the Victorian DNSPs and NIEIR. However, the AER notes that the forecasts are predicting a continuation of recent historical trends, which the AER considers is reasonable.

The AER notes that the factors affecting GSP and population growth forecasts are also likely to affect NIEIR's customer number forecasts and therefore expects these will all be updated for the Victorian DNSPs' revised proposals. This is discussed further in section 5.6.4.

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52 ibid., p. 37.
53 ibid..
54 CitiPower, email to AER staff, 22 March 2010.

5.6.4 NIEIR input assumptions

NIEIR’s forecasts of demand, energy and customer numbers are based on a number of input assumptions for each DNSP's region, mainly:

- economic growth or GSP
- air conditioning sales
- population.

The AER's assessment of these assumptions, their application and their impact on the reasonableness of the Victorian DNSPs' proposed forecasts are assessed in turn below.

Economic growth

NIEIR's Victorian GSP forecasts take into account government and private consumption and investment, population, private dwelling investment, state final demand and employment. These forecasts are used as an input into NIEIR's demand forecasting models (energy consumption and temperature insensitive maximum demand) for households to forecast changes in income. Forecasts by industry are also used as an input for commercial and industrial demand growth.

NIEIR's forecast of Victoria's GSP is disaggregated into gross regional product (GRP) forecasts for each DNSP's region, which are an input for its system level forecasts.[55] NIEIR’s regional model estimates GRP by industry across Victorian statistical divisions and local government areas. The key indicators at the regional level were population, dwelling stock and GRP by industry.[56]

Submissions

In its submissions on Powercor's, SP AusNet's and United Energy's regulatory proposals, TRUenergy noted the Victorian DNSPs' pessimistic economic growth forecasts as compared to those within AEMO's 2009 SOO. TRUenergy noted that AEMO's forecasts were prepared at the height of the GFC, and therefore considered that its high growth scenario is likely to reflect a more accurate economic growth forecast than the medium scenario.[57]

Consultant review

ACIL Tasman compared Victorian GSP growth from 2005 to 2009 with NIEIR’s forecasts and that of the Victorian Treasury over the period 2010–15.

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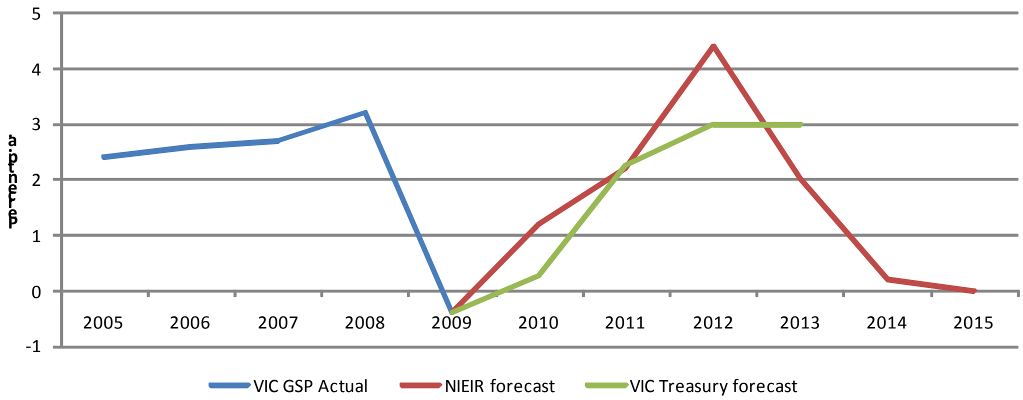
55 For example see NIEIR, *Maximum demand forecasts for SP AusNet*, pp. 27–30.

56 ibid.

57 TRUenergy, *Powercor Australia—Electricity Distribution Price Review 2011–15—Regulatory proposal*, February 2010; pp.2–3; TRUenergy, *SPI Electricity Pty Ltd—Electricity Distribution Price Review 2011–15—Regulatory proposal, February 2010*, pp.2–3; TRUenergy, *United Energy Distribution—Electricity Distribution Price Review 2011–15—Regulatory proposal*, February 2010, pp.2–3.

Figure 5.3 NIEIR and Victorian Treasury GSP growth forecasts 2010 to 2015

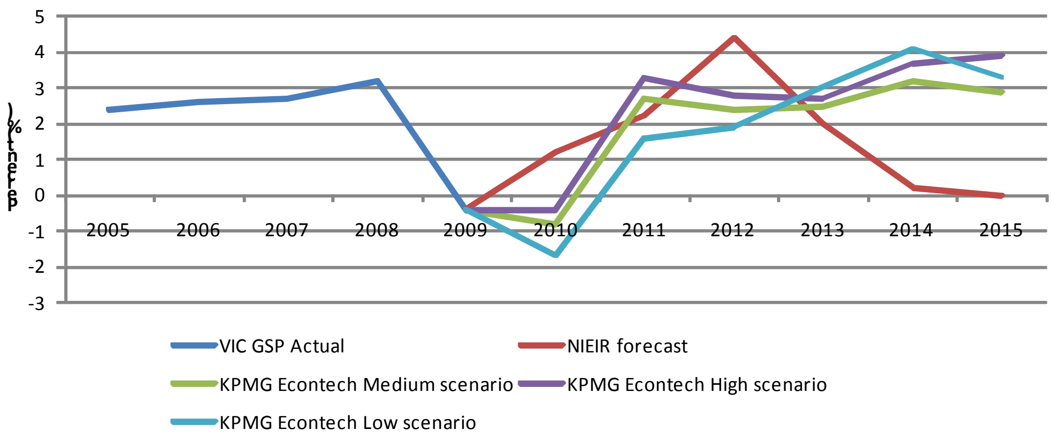


Source: ACIL Tasman, *Review of electricity sales and customer number forecasts*, p. 16.

ACIL Tasman noted NIEIR's economic growth forecast is more optimistic than forecasts prepared by Victorian Treasury for the first half of the forthcoming regulatory control period (2.5 per cent compared to 2.1 per cent for 2009–13), while for the second half of the regulatory control period, NIEIR's forecasts are more pessimistic, predicting GSP growth of close to zero.[58]

ACIL Tasman also compared NIEIR's GSP forecasts with those prepared by KPMG Econtech for VENCorp's 2009 APR. ACIL Tasman found that NIEIR's forecasts are for significantly lower in the medium term (0.2 per cent in 2014–15 compared to 3.2 to 2.9 per cent for the same period forecast by KPMG Econtech).

Figure 5.4 NIEIR economic growth forecasts versus KMPG Econtech



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 17.

Overall, ACIL Tasman considered that if NIEIR's economic growth forecasts were prepared in early 2010, rather than November 2009, they may be higher. In this regard, ACIL Tasman noted recent comments by the Reserve Bank of Australia

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58 ACIL Tasman, *Review of maximum demand forecasts*, p. 24.

regarding recent improvements in Australia's economic performance.[59] ACIL Tasman recommended to the AER that it consider requesting that the Victorian DNSPs use updated economic growth forecasts.[60]

AER considerations

The AER considers NIEIR's November 2009 analysis of the economic and demographic outlook for the Victorian DNSPs, in terms of state growth in Victoria and regional demand growth for the respective DNSPs, is consistent with forecasts conducted by the Department of Treasury and Finance and KPMG Econtech in April 2009. The AER considers that under normal economic conditions, it may have been appropriate to compare forecasts conducted in April with those conducted in November of the same year. However, the AER does not consider 2009 as a year reflective of normal economic conditions as forecasts conducted in April 2009 were significantly tempered by the global financial crisis. This is evident by examining the sentiments which accompanied the April 2009 forecasts. For example, in May 2009 the Victorian Government stated:

> In the face of the Global Financial Crisis, the economic outlook for Victoria has been revised down. Victoria's gross state product is expected to grow by 0.5 per cent in 2008–09 and 0.25 per cent in 2009–10, followed by a gradual recovery to trend rates of growth by the end of the estimates period.[61]

This is in contrast to the Victorian Government's November 2009 budget update, which stated:

> The Australian and Victorian economies have not been immune to the global recession but have been more resilient than many other advanced economies. This is in part due to a healthier banking system, strong population growth, access to faster growing export markets in Asia, and greater monetary and fiscal policy flexibility...
>
> **Projections for Victorian growth have been revised upwards. Gross state product (GSP) is forecast to grow by 1.5 per cent in 2009–10 and by 2.5 per cent in 2010–11.** The domestic economy has been supported by a mix of policy stimulus and sound fundamentals. As the stimulus ends, private demand will need to gain momentum to sustain the recovery. [Emphasis added] [62]

The AER notes more recent information in the Victorian state budget for 2010–11, which forecasts GSP to grow by 3.25 per cent in 2010–11 and 3 per cent per annum over 2011–13 (financial years).[63]

While the AER appreciates that NIEIR's forecasts were based on information available at the time they were prepared, it considers they are now outdated. Accordingly, for the purposes of this draft decision, the AER considers that the

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59 ibid., p. 25.

60 ibid., p. 26.

61 Victorian Department of Treasury and Finance, *2009–10 Budget Paper No. 2—Strategy and Outlook*, Victorian Budget 2009–10, May 2009, p. 19.

62 Victorian Department of Treasury and Finance, *2009–10 Budget Update*, 26 November 2009, pp. 1 and 13.

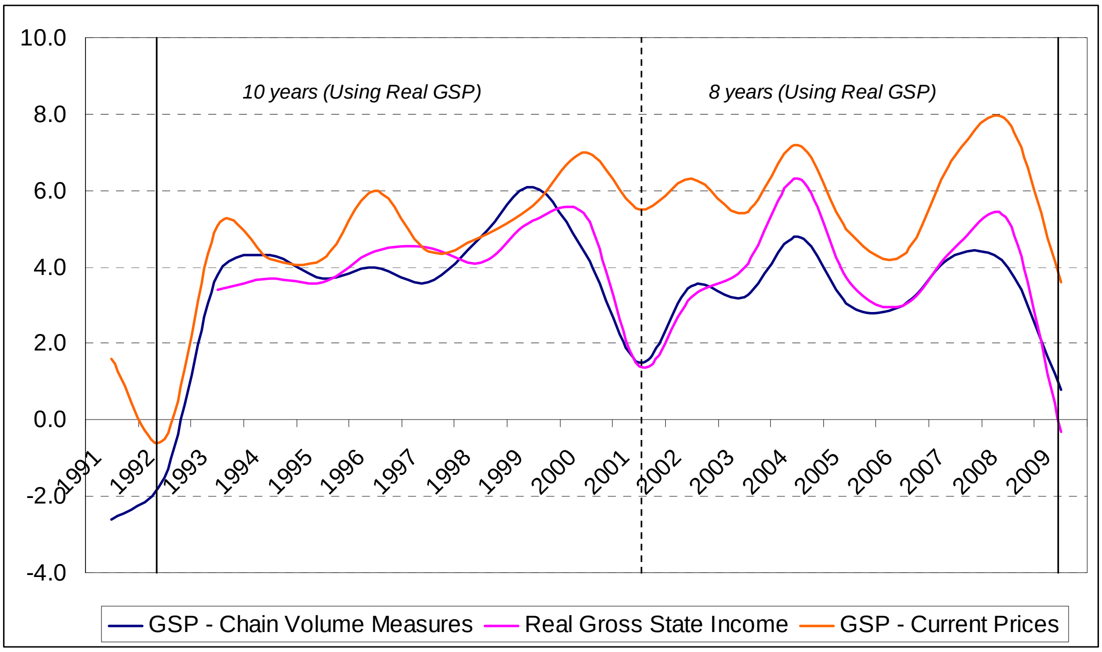
63 Victorian Department of Treasury and Finance, *2010–11 Budget Paper No. 2—Strategy and Outlook*, p. 17–19.

Victorian DNSPs' forecasts are unreasonable for the principal reason that they reflect outdated economic growth assumptions and expects more optimistic forecasts to be incorporated into the Victorian DNSPs' revised proposals.

Regardless of the overall level of forecast GSP growth, the AER also considers NIEIR's assumption of a five year business cycle (from trough to peak to trough) is unusual compared to what has been observed historically in Australia and Victoria. Figures 5.5 and 5.6 illustrate GSP over the past 19 years and GDP over the past 40 years respectively.

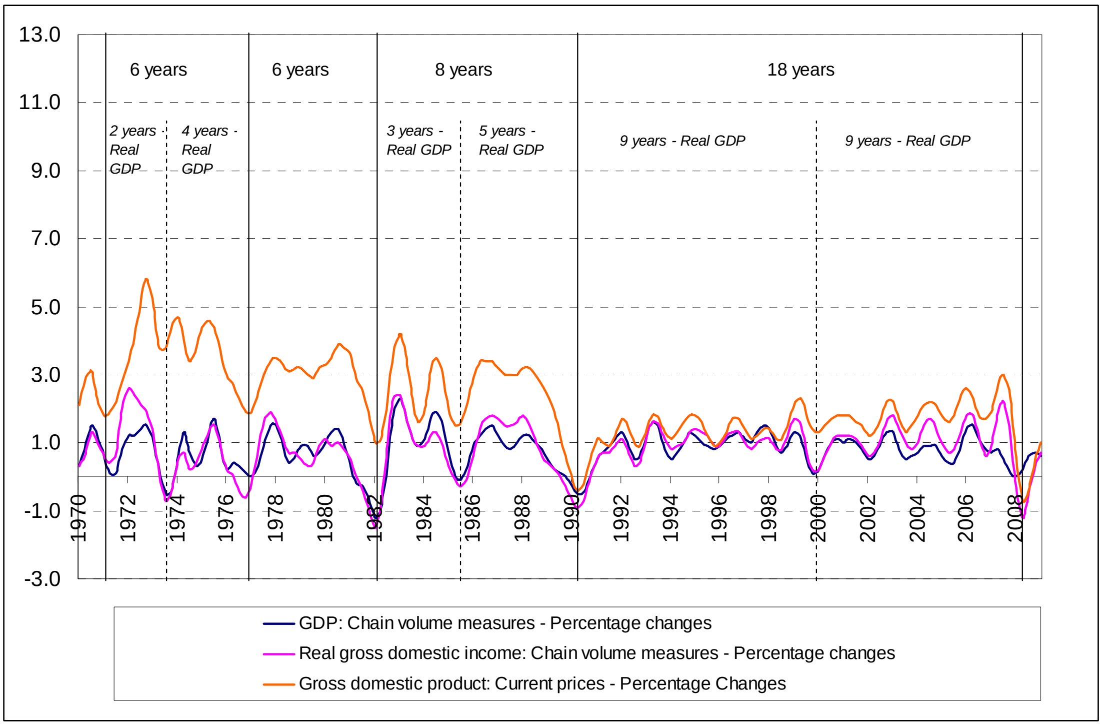
The AER considers it is more appropriate to examine business cycles using current prices (nominal measures). This is because a period of expansion can also lead to higher levels of (demand pull) inflation, which reduces real GDP but does not necessarily mean there has been a decline in the business cycle. That said, for completeness, the AER has examined potential business cycles by also examining real GDP.

Figure 5.5 Victorian gross state product (GSP)



Source: ABS, *Time series workbook 5220.0 – Australian National accounts: State accounts – table 1. GSP*; AER analysis.

Figure 5.6 Australian gross domestic product (GDP)



Source: ABS, *Time series workbook 5206.0 – Australian national accounts: National income – table 1. Key national accounts aggregate*, AER analysis.

The AER notes the GSP figures are only available for the 19 years, a period over which there has been a high level of stability. This stability can be observed by the long business cycles (18 years for GDP, and 8 to 10 years for real GSP). This examination of GDP is relevant because GSP is expected to strongly correlate to GDP. The AER notes that the business cycles between 1970 and 1990 appear to range from six to eight years. This is in contrast to NIEIR's forecast business cycle of five years. The AER considers a business cycle of five years is conservative in the absence of information other than anecdotal evidence and considers a longer business cycle would reflect a more reasonable expectation.[64]

Growth in air conditioning sales

The use of air conditioners has a significant impact on electricity demand in Victoria on high temperature days. The percentage of households with air conditioner units ('penetration') has increased steadily over time as show in figure 5.7.

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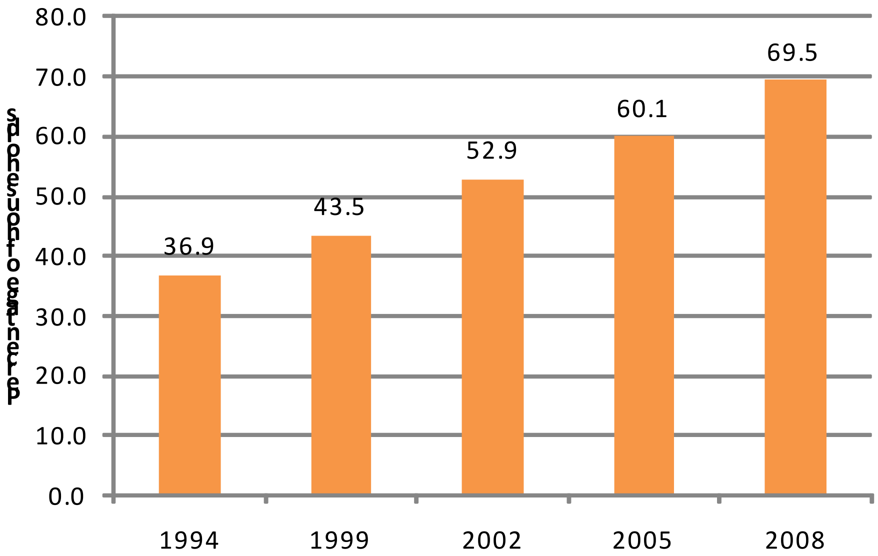
64 For example, NIEIR attempts to draw parallels between the Argentinean economy in 2001 in respect of private debt levels. However, it did not conduct a thorough comparative analysis between Argentina in 2001 and present day Australia. It would be expected that contrasting regulatory environments in the banking sectors (2001 in Argentina and the present in Australia) and monetary policy stances (for example, pegging currencies to the USD) could lead to quite different outcomes than experienced in Argentina in 2001.

Figure 5.7 Victorian penetration of air conditioners 1994 to 2008



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 26.

NIEIR forecasted a slowdown in air conditioner sales although these are expected to remain strong for the forthcoming regulatory control period.[65] NIEIR's forecast growth rate for air conditioners is 4.0 per cent per annum over the forthcoming regulatory control period, compared to the observed actual growth of 7.2 per cent over 2004–09.[66]

Consultant review

ACIL Tasman noted forecasts from the Australian Bureau of Statistics (ABS) and the Department of Environment, Water, Heritage and the Arts (DEWHA) which predicted strong, continued growth in air conditioner sales for a number of years before market saturation is reached.[67] Based upon this data, ACIL Tasman disagreed with NIEIR's forecast slowing air conditioning penetration rate. However, ACIL Tasman did not consider that NIEIR's air conditioner penetration rate was unreasonable.

ACIL Tasman noted the trends in South Australia and the Northern Territory, as shown in figure 5.13, which indicate that slowing air conditioner penetration (or saturation) occurs at higher penetrations (80 per cent) than Victoria's current rate of around 70 per cent.[68]

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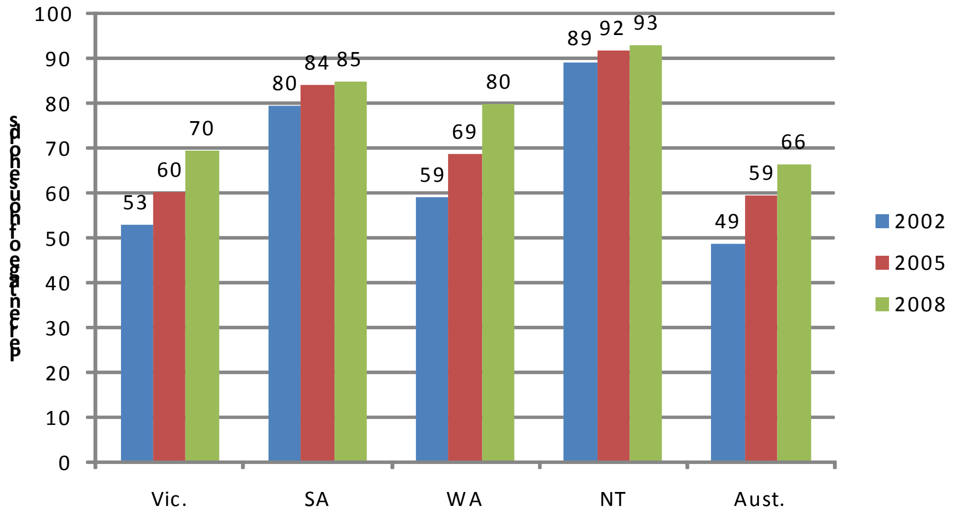
65 For example, see NIEIR, *Maximum demand forecasts for SP AusNet*, pp. 35–36.
66 For example, see NIEIR, *Electricity sales and customer number forecasts for SP AusNet*, p. 75.
67 ACIL Tasman, *Review of maximum demand forecasts*, p. 27.
68 ibid.

Table 5.13 Market penetration of air conditioners—Victoria and other jurisdictions



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 27.

Further to this, ACIL Tasman also noted this data projects growth to slow moderately compared to the previous five years. This is reasonably consistent with NIEIR's forecast scenario which has air conditioner sales also growing strongly but at a slower rate relative to the current regulatory control period.[69]

AER considerations

The AER acknowledges the information from the ABS and DEWHA which suggests that growth in air conditioner sales in Victoria should remain strong for the next few years before reaching market peak. The AER agrees with ACIL Tasman's view that growth in air conditioner sales should continue to be strong for a number of years before market saturation is approached. That said, consistent with ACIL Tasman's position, the AER considers that NIEIR's forecast of a forthcoming slowdown in air conditioner sales appears to be reasonable. The AER also considers that surveys of load type and customer appliance usage would add valuable information to NIEIR's maximum demand forecasts for each of the Victorian DNSPs.

Population growth

Population growth is also used as a key input for forecasting energy consumption. Population growth can be a driver for household formation (for example, immigration and emigration) and hence it is also linked to residential customer numbers for the DNSP.

DNSPs regulatory proposals

NIEIR has projected a slowdown in Victorian population growth for the forthcoming regulatory control period.[70] In the six years to June 2015, NIEIR projects an annual average rate of population growth rate of 1.25 per cent.

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69 ibid., p. 27.

70 For example, see NIEIR, *Maximum demand forecasts for SP AusNet*, pp. 27–30.

Submissions

In its submission to the AER, the Victorian Council of Social Services (VCOSS) noted:

> …both Jemena's and CitiPower's forecasts of population growth were lower than the official average projected population growth for the State.[71]

VCOSS also observed that the population projections from the Department of Planning and Community Development (DPCD) have identified the distribution areas of Jemena and CitiPower as high growth areas within metropolitan Melbourne.[72]

Consultant review

ACIL Tasman noted NIEIR's population growth forecast is among the lowest of the recent forecasts of the ABS and the Victorian Treasury. This is shown in table 5.14.

Table 5.14 NIEIR population growth projections versus Treasury and ABS forecasts, 2009–10 to 2014–15 (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	Average
NIEIR	1.5	1.3	1.2	1.1	1.2	1.2	1.2
Treasury	1.6	1.5	1.4	1.4	–	–	1.5
ABS Series A	1.5	1.5	1.5	1.5	1.5	1.5	1.5
ABS Series B	1.4	1.4	1.4	1.4	1.4	1.3	1.4
ABS Series C	1.4	1.3	1.3	1.3	1.2	1.2	1.3

Source: ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, p. 13.

In observing that NIEIR's population growth forecast is equivalent to the most pessimistic ABS forecast, ACIL Tasman considers it to be unreasonably pessimistic, particularly in light of recent growth.[73] ACIL Tasman also considered it unlikely that birth rates will change significantly over such a short time frame and hence the NIEIR forecasts would imply significantly lower migration rates over the period. As unemployment appears to have peaked below 6 per cent in the current cycle, it is unlikely that migration rates would slow.[74]

AER considerations

The AER considers that NIEIR's population forecasts are unreasonably low when compared to historical growth rates and the projected growth forecasts from Treasury and the ABS. The forecasts developed independently by the ABS and Treasury are consistent and in this sense corroborate one another. While NIEIR has pointed out the population growth of the last five years has been due to natural increase, overseas

71 VCOSS, *Submission to the AER*, p. 2.
72 ibid.
73 ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, p. 13.
74 ibid.

migration and relatively few interstate migration losses, NIEIR does not provide any evidence to suggest that this will change in the forthcoming regulatory control period.

While the VCOSS submission observed that DPCD population projections identified the distribution areas of Jemena and CitiPower as high growth areas within metropolitan Melbourne, the AER notes that this is not reflected in the relevant forecasts in the proposals of these DNSPs.[75] The AER considers that this is consistent with its view that NIEIR's population forecasts appear to be overly conservative.

Accordingly, the AER rejects NIEIR’s population growth forecasts used as an input into NIEIR's energy forecasting models. The AER considers that the Victorian DNSPs' forecasts should be based on a population growth assumption that at least matches the ABS series B forecasts (as provided in table 5.14) as this represents a moderate rate of population growth.

By applying this input assumption, the AER has made adjustments to the Victorian DNSPs' energy forecasts in accordance with table 5.15. These adjustments were calculated by ACIL Tasman using an average energy consumption per head of population, and applying this to the ABS population forecasts, which was then apportioned to each DNSP in relation to its population share.

Table 5.15 Change in energy consumption forecasts from applying ABS population inputs (MWh)

	Population share (per cent)	2010	2011	2012	2013	2014	2015
CitiPower	12	61	119	209	353	485	549
Powercor	29	148	293	512	865	1189	1344
Jemena	12	60	117	205	347	477	540
SP AusNet	24	124	245	429	724	995	1126
United Energy	23	120	237	414	700	963	1088
Total	**100**	**513**	**1011**	**1769**	**2990**	**4109**	**4647**

Source: ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, p. 14.

The AER notes that applying the MWh increases set out in table 5.15 to the Victorian DNSPs' forecasts may be an imperfect approach to incorporating a revised population growth assumption. The AER also notes that while ACIL Tasman calculated these approximate impacts, it did not recommend the AER apply them as they were subject to several shortcomings, for example they ignore the presence of other factors affecting consumption such as weather and economic growth.[76] However, the AER considers this approach is the best available to it and reasonable given the limited information it has about the calculations underlying NIEIR's energy forecasting

[75] VCOSS, *Submission to the AER*, p. 2.
[76] ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, pp. 14–15.

model. The AER notes that the Victorian DNSPs' revised regulatory proposals provide them the opportunity to propose an alternative approach to incorporating these population growth inputs.

5.6.5 'Post model' policy adjustments and the CPRS

This section examines NIEIR's forecasts for the Victorian DNSPs with respect to assumed impacts of various policies either in the preparation of 'base' forecasts or as post model adjustments. Most of the policies considered in this section do not have any historical precedents and therefore there is a high level of uncertainty in respect of their likely impact. The following policies are examined here:

- Mandatory Energy Performance Standards (MEPs) for lighting and air conditioning
- CPRS
- other initiatives and schemes.

The AER notes that AMI is considered separately in the next section.

Summary of policy adjustments

Tables 5.16 and 5.17 summarise the forecast policy adjustments made by NIEIR with respect to its ‘base’ forecasts of maximum demand and energy consumption.

Table 5.16 NIEIR forecast cumulative policy adjustments, maximum demand (MW)

Policy (MW)	2011	2012	2013	2014	2015
Standby power	–3	–10	–16	–23	–29
Insulation	–21	–25	–25	–25	–25
Photovoltaics	–16	–19	–22	–24	–25
MEPs air conditioners	–11	–20	–30	–39	–47
6 star building standards	0	–1	–2	–4	–5
Total policy impacts	**–51**	**–74**	**–95**	**–114**	**–131**

Source: NIEIR maximum demand reports tables 6.3 and 6.6, AER analysis.

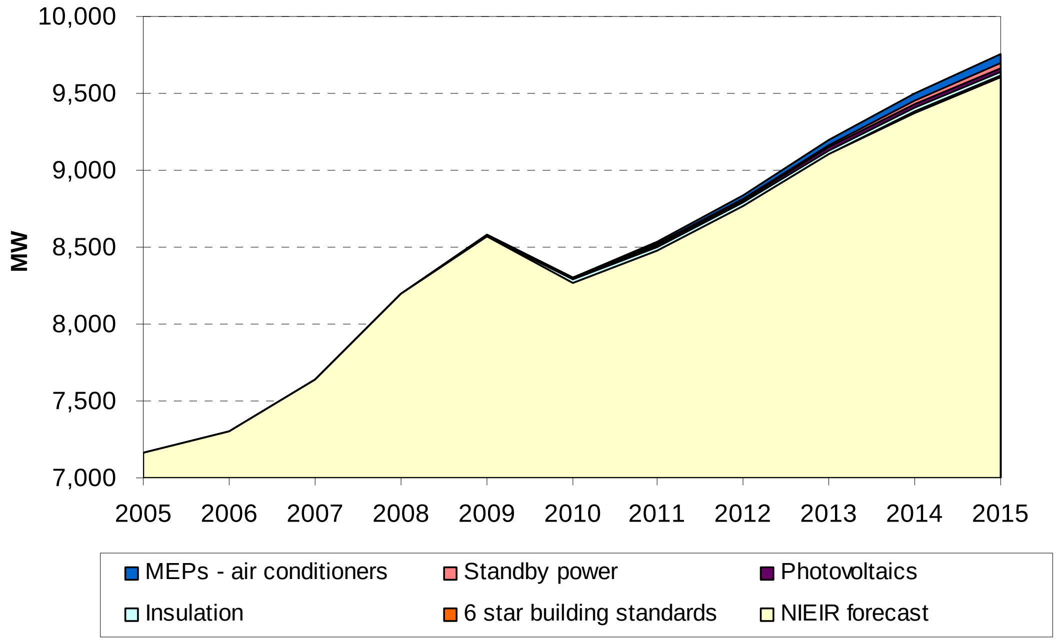
Table 5.17 NIEIR forecast cumulative policy adjustments, energy consumption (GWh)

Policy (GWh distributed)	2011	2012	2013	2014	2015
MEPs lighting	–468	–624	–717	–748	–780
Standby power	–27	–82	–137	–173	–190
Insulation	–111	–134	–134	–134	–134
Photovoltaics	–22	–26	–29	–32	–34
VEET	–50	–68	–86	–108	–122
Hot water	–51	–84	–115	–146	–174
MEPs air conditioners	–9	–15	–23	–29	–35
6 star building standards	0	–1	–4	–7	–9
Electric cars (off peak)	17	24	31	37	44
Total policy impacts	**–720**	**–1009**	**–1214**	**–1339**	**–1434**

Source: AER analysis, and NIEIR energy consumption reports tables 6.2 and 6.5.

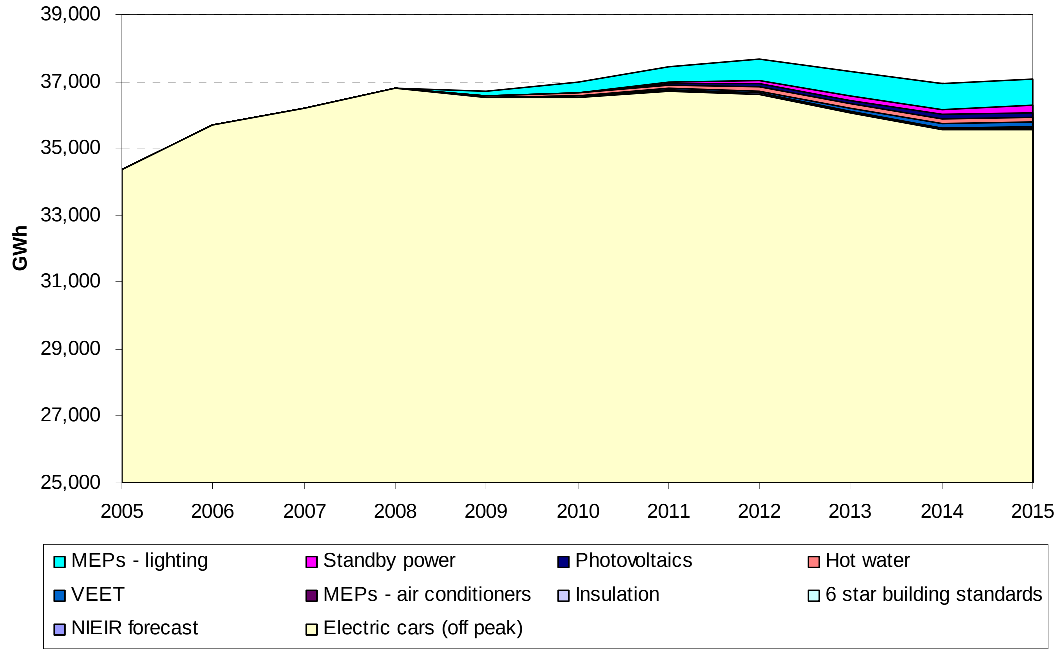
Figures 5.8 and 5.9 illustrate the impact of the policy adjustments on the overall forecasts.

Figure 5.8 NIEIR's forecast cumulative policy adjustments (maximum demand)



Source: AER analysis, DNSP regulatory proposals and NIEIR maximum demand reports tables 6.3, 6.6, 10.4 and 10.6.

Figure 5.9 NIEIR's forecast cumulative policy adjustments (energy consumption)



Source: AER analysis, DNSP regulatory proposals and NIEIR energy consumption reports tables 6.2 and 6.5.

Mandatory Energy Performance Standards (MEPs) for lighting and air conditioning

MEPs for lighting involves the removal of most incandescent light globes and some low voltage halogen lights from sale, with the MEPs requirements set at a minimum of 15 lumens per watt.[77] In 2010 MEPs for air conditioning have been increased, requiring units under 4 kW must meet a minimum of 3.33 Energy Efficiency Rating/Coefficient of Performance (EER/COP), as compared to the current value of 3.09 EER/COP.[78]

Victorian DNSPs proposals

NIEIR assumed the MEPs for lighting will have no impact on summer maximum demand, as demand usually peaks whilst the sun is up and, therefore, residential lighting contribution will be very small.[79]

NIEIR estimated the MEPs for lighting impact on energy consumption by assuming:

- an average number of lights per household, a usage rate and an average watt input for residential customers
- an average number of light bulbs per square meter, a usage rate, a penetration rate, and average watt input

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77 For example see NIEIR, *Maximum demand forecasts for SP AusNet*, p. 59.
78 ibid., p. 60.
79 ibid., pp. 55 and 57.

- the number of light bulbs changing from incandescent to compact florescent lights (CFLs) for residential and commercial customers increasing over the forthcoming regulatory control period.[80]

NIEIR relied on a study which found most air conditioners available under 4 kW already meet or exceed the 2010 MEPs. It noted discussions with air conditioner manufacturers about the way the MEPs requirements are met and how improvements in EER/COP translate into lower peak performance improvements. Overall, NIEIR considered the MEPs air conditioning would have a negligible impact on maximum demand and energy consumption.[81]

Consultant review

Based on meetings with NIEIR and the Victorian DNSPs, ACIL Tasman reported its understanding of the assumptions used, which are:

- 95 per cent of dwellings in Victoria would be occupied at any given time
- each dwelling will have, by the beginning of the forthcoming regulatory control period, six 'eligible' lamps remaining
- the average 'eligible' lamp is a 75W incandescent globe
- the average replacement globe will draw 15W
- all eligible globes will be replaced during the forthcoming regulatory control period.[82]

ACIL Tasman accepted NIEIR's position that the impact for MEPs for lighting is likely to have a trivial impact on maximum demand over the forthcoming regulatory control period and is likely to be small enough to fall well within forecast error.[83]

ACIL Tasman compared NIEIR's forecast reduction in energy consumption due to MEPs for lighting with the Australian Government's Final Regulatory Impact Statement (RIS) on MEPs for lighting. This latter document was published in May 2009.[84] ACIL Tasman made the following observations:

- At the time the Australian Government's modelling for the RIS was conducted, tungsten filament lamps were widely available for sale and MEPs had not been announced—the task at the time was to estimate the total impact of MEPs.
- The Australian Government's modelling is published on only an aggregated basis, with residential, commercial and industrial impacts rolled together—a direct comparison is not possible without reconstructing the RIS estimates:

80 For example see NIEIR, *Electricity sales and customer number forecasts for SP AusNet*, pp. 53–54.
81 For example see NIEIR, *Maximum demand forecasts for SP AusNet*, p. 60.
82 ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, p. 24.
83 ACIL Tasman, *Review of maximum demand forecasts*, p. 30.
84 ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, p. 25.

- In 2005, the average Australian home used 684 kWh of electricity for lighting (annually), if MEPs compliant lights were introduced overnight, energy sales would reduce by 32.5 per cent—the average Australian home would use 222 kWh less electricity for lighting than they would otherwise have used.

- NIEIR's task was not the same task as the Australian Government—NIEIR's task was to estimate the residual impact of MEPs for lighting

- It is expected NIEIR's estimates of the impact should be less than that contained in the RIS.

- NIEIR assumed all incandescent lights were replaced by CFLs while the Australian Government allowed for the possibility of tungsten halogen globes (with smaller efficiency gains as a result).[85]

Based on the above observations, ACIL compared the impact modelled by NIEIR to the Australian Government's RIS.

Table 5.18 ACIL Tasman comparison of lighting MEPs impact on residential electricity sales

	2011	**2012**	**2013**	**2014**	**2015**
Projected number of households in Victoria ('000 households)	2122	2155	2190	2225	2261
Lighting energy use if no MEPs (GWh)	1451	1474	1498	1522	1546
Lighting use with MEPS (GWh)	980	995	1011	1027	1044
Reduction due to MEPs compliance (GWh)	472	479	487	495	503
NIEIR's forecast (aggregated GWh)	333	443	509	531	554
Difference (GWh)	**–139**	**–36**	**23**	**37**	**51**

Source: ACIL Tasman, *Review of electricity sales and customer numbers forecasts,* table 6, p. 27.

ACIL Tasman observed NIEIR's estimates (in aggregate) are more than 10 per cent higher than the estimates used in the RIS.[86] ACIL Tasman considered the Australian Government's modelling was conducted at a detailed level. Therefore, ACIL Tasman recommended, as a minimum, the impact of lighting MEPs be constrained to the impact estimated by the Australian Government (noting that this remains likely to overstate the impact as the modelling did not take into account the tendency to 'move ahead' of the policy).[87]

ACIL Tasman noted NIEIR's MEPs for air conditioning forecasts is similar in the early years to the forecasts that VENCorp used in its 2009 APR, but did not grow as

85 ibid., pp. 24–28.
86 ibid., p. 26.
87 ibid., p. 26.

quickly.[88] ACIL Tasman noted that insufficient information was provided as to how the estimates on the impact of MEPs for air conditioning was calculated, and that it was therefore unable to reach a conclusion on the policy impact for either the Victorian DNSPs' energy or maximum demand forecasts.[89] However, for the energy forecast, ACIL Tasman noted that the impact of the policy was not sufficiently large to warrant a closer review.[90]

AER considerations

The AER considers the estimates provided by NIEIR with respect to the impact of MEPs for lighting for maximum demand are reasonable, as:

- the Victorian DNSPs' networks are summer peaking networks (usually around 3-4pm, depending on the location) and it is unlikely that many lamps will be switched on at this time in residential households
- a large number of industrial and commercial customers use florescent lights and therefore MEPs is likely to have a minimal impact on these customers
- ACIL Tasman concluded that the impact for MEPs for lighting is likely to have a negligible impact on maximum demand over the forthcoming regulatory control period and is likely to be small enough to fall well within the forecast error.[91]

The AER does not consider the estimated impact of MEPs for lighting is reasonable for all years in the forthcoming regulatory control period. The AER notes ACIL Tasman's analysis, which demonstrates that NIEIR's estimates for Victoria as a whole exceed the Australian Government's estimates for 2013–15.[92] The AER agrees with ACIL Tasman that:

- the modelling in the RIS is likely to be a conservative estimate as it examines the whole impact of MEPs for lighting and did not assume that households may 'move ahead' of policy
- NIEIR assumed that all incandescent lights would be replaced by CFLs, which may not necessarily be the case.

The AER agrees with the advice it received from ACIL Tasman, and considers the Victorian DNSPs' forecast impact should be constrained to the Australian Government's modelled impacts in the RIS. The AER considers NIEIR's estimated impacts for lighting MEPs be reduced by approximately:

- 4.5 per cent (23 GWh divided by 509 GWh) in 2013
- 7.0 per cent (37 GWh divided by 531 GWh) in 2014

88 ACIL Tasman, *Review of maximum demand forecasts*, pp. 37–38.
89 ibid., p. 38; ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, p. 29.
90 ACIL Tasman, *Review of electricity sales and customer numbers forecasts*, pp. 28–29.
91 ACIL Tasman, *Review of maximum demand forecasts*, p. 30.
92 ACIL Tasman, *Review of electricity sales and customer numbers*, pp. 25–26.

- 9.2 per cent (51 GWh divided by 554 GWh) in 2015.

The AER considers the estimates provided by NIEIR with respect to the impact of MEPs for air conditioning for maximum demand and energy consumption are reasonable, as:

- the estimated impacts on maximum demand are broadly consistent with the impact VENCorp reported in its 2009 APR

- the estimated impact on energy consumption is consistent with air conditioners having a long life cycle and Australian residents being a technology importer—and therefore it is assumed that most air conditioners installed in recent years already meet with MEPs for air conditioning standards.

CPRS

On 15 December 2008, the Commonwealth government released the White Paper on the CPRS. At the time, the White Paper confirmed an emissions trading scheme would be introduced by 2010–11. The Commonwealth government announced in May 2009 that the introduction of the CPRS has now been delayed to July 2011 and that permits would be capped at $10 per tonne in 2011–12, with the full market expected to commence in July 2012.

The AER expects that once the CPRS is implemented electricity prices will increase. The reasons for this are two-fold. First, a key feature of an emissions trading scheme is the placing of caps on greenhouse gas emissions. Any emissions above these caps will require the purchase of permits. Such costs are likely to be of significance in the electricity industry as a bulk of Australia's electricity generation involves coal fired generation. The second reason for the likely increase in electricity prices is the probable effect that a CPRS scheme would have in inducing a shift towards generation technologies that emit less greenhouse gasses. In general, these generation technologies are more costly. Overall, these additional costs are likely to result in increased generation costs flowing onto customers. Consequently, demand forecast models need to account for any price increases.

DNSPs proposals

NIEIR assumed for its base scenario the CPRS would commence on 1 July 2011 and would follow Treasury's CPRS–5 model out to 2015.[93] As outlined in section 5.6.3, NIEIR uses electricity price assumptions in its models that reflect the adoption of CPRS–5. Therefore, NIEIR did not provide alternative forecasts which excluded the impact of the CPRS.

Consultant review

ACIL Tasman considered at the time the Victorian DNSPs submitted their regulatory proposals in November 2009, it was reasonable to expect that the CPRS would commence on 1 July 2011 and follow something approximating the CPRS 5 path modelled by the Treasury.[94]

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93 For example see NIEIR, *Electricity sales and customer number forecasts for SP AusNet*, p. 40.
94 ACIL Tasman, *Review of maximum demand forecasts*, pp. 44–46.

ACIL Tasman noted the CPRS legislation has not passed Parliament at the time of writing its reports that and its future is uncertain. It considered there is at least some chance the CPRS will:

- be delayed beyond a mid 2011 start date
- be introduced in a modified form
- not be introduced at all.[95]

ACIL Tasman contended that the prospect of the CPRS commencing on 1 July 2011 in its existing form is remote. That said, ACIL Tasman also considered it unlikely, given the current environment, that a greenhouse emissions reduction policy would not be put in place in Australia during the forthcoming regulatory control period.[96] As ACIL Tasman was unable to provide a more accurate assumption about the implementation of the CPRS it accepted NIEIR's assumption.[97]

With respect to maximum demand, if the CPRS is delayed by another year (that is, 1 July 2012), then it would be reasonable to expect that electricity prices will be lower at any given time than those used in producing the forecasts. However, as the CPRS will have an impact on maximum demand via a price elasticity, ACIL Tasman did not expect the impact of a one year delay to have a material impact.[98] ACIL Tasman did note, on the other hand, that electricity consumption forecasts are likely to be biased downwards if the CPRS is delayed by a year.[99]

AER considerations

The AER notes two key issues that need to be considered when modelling for the impact of the CPRS:

- interaction with other policies (for example, MEPs and subsidy schemes) which may affect the customers' response to potential price increases[100]
- the implementation lags from a policy being passed in Parliament to its actual implementation.

The AER acknowledges that at the time NIEIR conducted its demand forecasts there was an expectation that the CPRS would be passed in late 2009 with a scheduled implementation for 1 July 2011. However, in April 2010 the Commonwealth Government announced that it ‘will not introduce the CPRS until after the end of the current commitment period of the Kyoto Protocol (which ends in 2012) and only

95 ibid.
96 ibid.
97 ibid.
98 ibid.
99 ACIL Tasman, *Review of electricity sales and customer numbers*, pp. 23–24.
100 For example in New South Wales, the State Government has recently announced that it will be offering rebates for families affected by recent increases in electricity prices. NSW Government, *Help for families to pay their energy bills*, Media release, 7 April 2010.

when there is greater clarity on the actions of other major economies including the US, China and India.'[101]

Therefore, the AER considers that the Victorian DNSPs' forecasts reflect an outdated assumption regarding the CPRS. While the AER has not made any adjustments to reflect this delay, it expects that the Victorian DNSPs will in their revised regulatory proposals update their forecasts to account for this issue.

Other initiatives and schemes

Apart from MEPs and CPRS, there are a number of other initiatives and schemes that have been implemented by the Victorian and Commonwealth governments, such as:

- Insulation rebate schemes—the Australian Government had an objective to see insulation installed in up to 1.9 million existing homes by 2011 by offering a $1200 rebate, which was claimed by the insulation installers.

- Photovoltaics (PV)—a number of Victorian and Australian initiatives support small scale solar electricity generators, including feed in tariffs and Renewable Energy Certificates (RECs) under the Mandated Renewable Electricity Target (MRET), solar panel rebates, etc.

- Victorian Energy Efficiency Target (VEET)—an initiative which commenced in January 2009, placing requirements on energy retailers to create and acquit certificates equal to a target that, in aggregate, amounts to 2.7 million tonnes of carbon dioxide emissions abated per year. A number of different activities can lead to the creation of certificates, including upgrading water heaters, space heaters, lights, shower heads or fridges.

- Hot water initiatives— numerous initiatives to reduce the load of hot water heating will be introduced or increased over the forthcoming regulatory control period.

- Residential building standards (five and six star ratings requirements) — Commonwealth and State governments have agreed to move from a five star minimum requirement for new homes, to a six star minimum requirement by 2012.

- The trial and introduction of electric vehicles—the Victorian Department of Transport is currently conducting a study on electric vehicles, and Mitsubishi is currently conducting a nation-wide feasibility test.[102]

Another initiative which has also been discussed in energy reports is standby power requirements, with a one watt target for standby power. The appliances that have been considered are:

- televisions

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101 Australian Government, *Carbon Pollution Reduction Scheme*, Media release, http://www.climatechange.gov.au/en/media/whats-new/cprs-delayed.aspx, accessed 5 May 2010.

102 Mitsubishi Motors, *Mitsubishi's i MiEV hits the road*, Media release, 23 March 2009.

- video and DVD players
- microwaves
- stereo and surround sound systems
- desktop and laptop/notebook computers
- printers/scanners/faxes
- games consoles
- washing machines.

Victorian DNSPs proposals

With respect to each of the schemes and initiatives, NIEIR proposed:

- Insulation rebate schemes—based on ABS data, NIEIR determined about three quarters of houses either did not have, or did not know, whether their household had insulation. NIEIR noted that if installed properly, insulation would reduce electricity usage by 35 per cent. However, to account for non compliant installation and any rebound effects, NIEIR discounted the impact by approximately by 30 per cent.

- The impact of PV—NIEIR assumed the number of annual PV installations peaks in 2009–10 and reduces throughout the forthcoming regulatory control period. It was also assumed that most households would typically install a 1 kW system which would operate on average for 8–10 hours per day and produce about 1.2 MWh per year.

- The VEET scheme— NIEIR assumed the impacts of the VEET scheme would have no impact on maximum demand and minimal impact on energy consumption over the forthcoming regulatory control period, as the scheme overlapped with a number of Victorian and Commonwealth government initiatives.

- NIEIR assumed hot water initiatives would have no impact on maximum demand, as water heating occurs in off peak periods. NIEIR used its own water heating model and made assumptions relating to customers switching from electric water to other forms of water heating (for example, solar, gas, etc).

- Residential building standards (increasing from a five star rating to a six star rating requirement in 2012)—NIEIR noted the electricity savings of up to 19 GWh from the standard switch. However, the impact on demand forecasts was assumed to be small due to overlaps with other policies and initiatives.

- Electric vehicles—NIEIR assumed these vehicles would be charged in off peak times and therefore would only impact on energy consumption. NIEIR used information from the Mitsubishi MiEV trial to make assumptions about the number of electrical vehicles and consumption.

- Standby power—based on ABS data, NIEIR noted standby power accounted for 11 per cent of electricity use in Australian households and commercial sectors (televisions and computers only), and assumed that the current standby power is about 4 watts on average. It was assumed this initiative would commence in 2012 and would result in reductions to maximum demand and energy consumption.[103]

Consultant review

Overall, ACIL Tasman concluded that NIEIR's assumed policy impacts on maximum demand were likely to be conservative and at the lower end of what may be expected to occur.[104] ACIL Tasman also had a number of concerns about several of the individual adjustments that were made for energy forecasts. ACIL Tasman's views on each policy impact are as follows:

- Insulation rebate schemes—ACIL Tasman noted at the time of writing its report the Commonwealth Government had discontinued the insulation scheme and had announced its intention to repackage the scheme as a new household renewable energy bonus scheme with an insulation component that would come into operation by 1 June 2010. ACIL Tasman considered that due to the uncertainty surrounding the scheme, it should be excluded from the forecasts until it is sufficiently clear whether the rebate will be continued and that it would not be changed in form.

- PV—ACIL Tasman compared the number of solar panels assumed by NIEIR to be installed with data held by DEWHA. ACIL Tasman noted that NIEIR had slightly underestimated the number of solar panels installed in Victoria for 2009 and that the forward estimates beyond 2010 were significantly above data for years prior to 2008–09. That said, ACIL Tasman did not regard NIEIR's estimated number of solar panels, or their impact on demand forecasts, as unreasonable.

- VEET—ACIL Tasman considered that NIEIR's assumptions would most certainly understate the effect of the VEET on maximum demand, however noted that it is not unreasonable to assume that the impact would be very small, especially in the first few years of the forthcoming regulatory control period. ACIL Tasman noted that VENCorp's 2009 APR assumed that VEET would have a negligible impact on maximum demand. ACIL Tasman also noted NIEIR's forecasts of the impact of VEET have been weighted down substantially to a modest level.

- Hot water initiative—ACIL Tasman summarised the impact of the initiatives as resulting in electric resistance water heaters disappearing from the range of available new hot water system options over the forthcoming regulatory control period. ACIL Tasman considered that electric resistance water heaters would usually be used at off peak times, and considered it reasonable to assume a negligible impact on maximum demand. ACIL Tasman contrasted NIEIR's estimates of consumption relating to water heated by electricity for residential customers (330 GWh per annum) with DEWHA's 2009 estimates (1750 GWh—approximately 3 MWh per household assumed to have electric water heating).

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[103] For example see NIEIR, *Maximum demand forecasts for SP AusNet*, pp. 55, 62–63, 65–66, 68, 70 and 75.

[104] ACIL Tasman, *Review of maximum demand forecasts*, pp. 29–46.

Further discussions with the Victorian DNSPs revealed the hot water reductions reported in NIEIR's tables are not relevant and should be disregarded. Rather, NIEIR makes assumptions about hot water initiatives in its demand forecast models.

- Residential building standards (five and six star ratings requirements)—ACIL Tasman considered the general trend in larger homes for increasing maximum demand would offset the effect of the six star standards on maximum demand in newly constructed homes. ACIL Tasman further considered that the portion of overall demand forecasts that would be affected by the policy would be modest.

- Electric Vehicles (ELVs)—ACIL Tasman did not regard the scenario assumed by NIEIR to be a reasonable prediction of the likely demands on the Victorian DNSPs. However, given that the estimates were so small, ACIL Tasman did not consider the forecasts for electric cars to be unreasonable.

- Standby Power—ACIL Tasman noted that it was not aware of a single, comprehensive committed policy of either the Commonwealth or the Victorian government, to introduce a mandatory requirement of this type. ACIL Tasman recommended the demand forecast reductions attributed to the one watt target should be disregarded. This is strengthened by the fact that a number of MEPs with one watt standby components are already in place and are thus influencing the data that feeds NIEIR's electricity sales model.[105]

AER considerations

The AER agrees with the advice it has received from ACIL Tasman and considers the policy adjustments made by NIEIR are acceptable, except for the hot water initiatives, the insulation rebate and one watt targets. In particular, the AER considers:

- The numbers reported in table 6.2 of NIEIR's energy sales and customer number reports for hot water have no bearing on the demand forecasts provided to the AER as reductions from customers switching from electric heating to other forms are accounted for within the demand forecast models and not through 'post model' adjustments.[106]

- NIEIR (on behalf of the Victorian DNSPs) has not demonstrated evidence of a government policy to implement a one watt target, further, it is likely the impact of one watt standby appliances has been accounted for under NIEIR's use of average household consumption in it electricity consumption model.

- Adjustments relating to the insulation target scheme should be removed—the AER notes the Australian Government announced that the insulation rebate

[105] ACIL Tasman, *Review of maximum demand forecasts*, p. 46; ACIL Tasman, *Review of electricity sales and customer numbers*, pp. 21–59.

[106] For example, see NIEIR, *Electricity sales and customer number forecasts for SP AusNet*, p. 49.

scheme is to be discontinued with the remaining funds in the scheme to fund safety switches for houses with foil insulation and inspections.[107]

Tables 5.19 and 5.20 summarise the AER's adjustments to the Victorian DNSPs' forecasts arising from its considerations of policy impacts.

Table 5.19 AER forecast cumulative policy adjustments, maximum demand (MW)

	2011	2012	2013	2014	2015
Total policy impacts—DNSPs	–51	–74	–95	–114	–131
AER adjustment—standby power	3	10	16	23	29
AER adjustment—insulation	21	25	25	25	25
Total policy impacts—draft decision	–27	–39	–54	–66	–77

Source: AER analysis; NIEIR maximum demand reports tables 6.3 and 6.6.

Table 5.20 AER forecast cumulative policy adjustments, energy consumption (GWh)

	2011	2012	2013	2014	2015
Total policy impacts—DNSPs	–720	–1009	–1214	–1339	–1434
AER adjustment—MEPs lighting	0	0	23	37	51
AER adjustment—standby power	27	82	137	173	190
AER adjustment—insulation	111	134	134	134	134
Total policy impacts—draft decision	–582	–793	–920	–995	–1059

Source: AER analysis; NIEIR energy consumption reports tables 6.2 and 6.5.

5.6.6 Review of DNSP spatial demand forecasts

This section examines each DNSP's 'bottom up' maximum demand forecasts for each zone substation (ZSS). The demand forecasts at this 'spatial' level of the network are a major driver of the capex requirements of each DNSP.

The spatial forecasts prepared by each DNSP involve the following general steps:

- individual forecasts for each ZSS are prepared, in some cases taking into account historic growth rates, weather, expected future growth, impacts of large new developments and load transfers
- these forecasts are aggregated together, taking account of diversity, to the terminal station level

[107] Minister Assisting the Minister for Climate Change and Energy Efficiency, *Insulation component of the renewable energy bonus scheme will not proceed*, Media release, 22 April 2010.

- in most cases these are then compared to the terminal station forecasts prepared by NIEIR, with some adjustments made to ZSS forecasts as a result.

Overall, and as highlighted by ACIL Tasman, the Victorian DNSPs, to varying degrees, utilise judgment in setting growth rates at the ZSS level. While this is not necessarily inappropriate, how this judgment is applied is, in most cases, not transparent and therefore not replicable. As noted by the AER above this is a weakness in the forecasting approaches used by each DNSP.

Furthermore, while the Victorian DNSPs have engaged NIEIR to develop a top down system wide forecast which incorporates weather, government policy and other macro variables, none of the Victorian DNSPs fully reconcile to this forecast. ACIL Tasman has advised the AER that it considers the Victorian DNSPs' ZSS forecasting methodologies (to varying degrees) do not adequately account for a number of factors relevant to forecasting maximum demand, including economic conditions in the forecast period and the impact of government policies. The fact that the ZSS forecasts are not overly transparent and subject to judgment further underlines the importance of validating these through an independently developed top down forecast.

The AER considers that a full reconciliation between the Victorian DNSPs' bottom up forecasts to NIEIR's top down forecasts is an essential element in producing reasonable forecasts at the ZSS level on which the Victorian DNSPs' capex forecasts are based. The AER considers that such reconciliation would produce reasonable forecasts and result in a reduction to the sum of the ZSS forecasts produced by the Victorian DNSPs.

ACIL Tasman has advised the AER that such reconciliation should take into account the specific characteristics of each ZSS where possible.[108] The AER has done this based on the information provided by the Victorian DNSPs for the purposes of this draft decision, however expects this reconciliation could be refined (if necessary) with the provision of better information to the AER in advance of its final determination. Specifically, for this draft decision, the AER has followed ACIL Tasman's recommendation to maintain the percentage difference between the sum of the DNSPs' ZSS non-coincident maximum demands and NIEIR's system maximum demands in historic observations and in forecasts.

Further details for each DNSP are outlined in the next sections, followed by the AER's overall conclusions with respect to the Victorian DNSPs' spatial forecasts.

CitiPower

CitiPower prepares maximum demand forecasts for each ZSS through the following steps:

- the most recent actual summer and winter maximum demand is weather corrected to reflect 50 PoE conditions, based on analysis of the relationship between temperature and demand

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108 ACIL Tasman, *Review of maximum demand forecasts*, pp. 2–3.

- growth rates are applied to this adjusted demand, reflecting new known loads (taking into account probability and diversity factors) and general expected growth specific to each ZSS area

- adjustments for load transfers between distribution feeders or ZSS. [109]

CitiPower indicated it did not compare its ZSS forecasts with the terminal station forecasts prepared by NIEIR.[110]

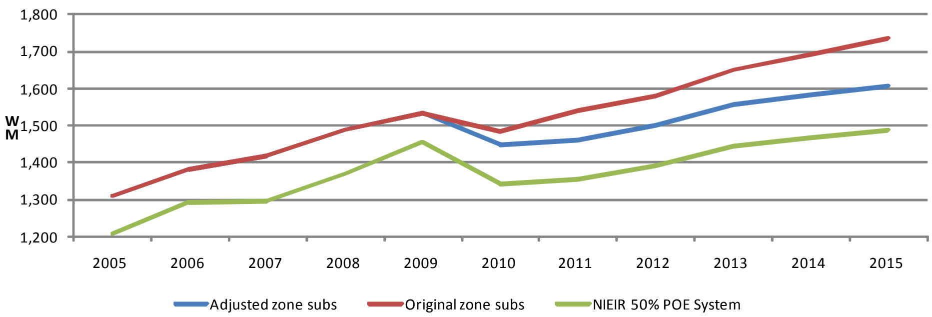
As illustrated by ACIL Tasman (see figure 5.10), CitiPower's bottom up and NIEIR's top down forecasts diverge over time. While noting that CitiPower's and NIEIR's actual historic data series were not identical, it considered there are two main reasons why the two sets of forecasts show an increasing divergence: [111]

- insufficient temperature correction in first year of the forecast period

- not sufficiently accounting for NIEIR's slower economic and population growth outlook compared to that observed historically.[112]

ACIL considered NIEIR's forecasts are more statistically robust in taking into account weather impacts and recommended that the difference between the two series should be reduced to the historical average observed between 2005 and 2008, which was 7.8 per cent. ACIL Tasman noted that from applying this level of diversity into the forecast period, it obtained the following forecasts as provided in figure 5.10.

Figure 5.10 Adjusted CitiPower 50 PoE non-coincident zone substation forecasts versus NIEIR 50 PoE system forecasts



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 63.

The AER highlights the inconsistencies between CitiPower's regulatory proposal which states that it engaged NIEIR to ‘verify internally generated maximum demand forecasts’[113] and has further commentary in support of NIEIR's expertise, and its subsequent comment that it ‘does not use NIEIR as a comparison with their

[109] CitiPower, *Regulatory proposal*, p. 33.
[110] CitiPower, *response to questions on non–coincident demand*, 19 February, p. 6.
[111] For example, because NIEIR includes forecasts for terminal stations not recognised by CitiPower.
[112] ACIL Tasman, *Review of maximum demand forecasts*, pp. 57–58.
[113] CitiPower, *Regulatory proposal*, p. 32.

forecasts'.[114] The AER questions why CitiPower would engage NIEIR to perform an independent top down forecast and then effectively ignore this work.

In this context, the AER is concerned at the significant divergence between CitiPower's ZSS forecasts and NIEIR's top down forecasts. Given CitiPower's view that 'the forecasts prepared by NIEIR are reliable and robust'[115] the AER would expect that CitiPower would have adjusted its ZSS forecasts or provided some explanation in its proposal why it considered adjustments were not required.

In the absence of any such justification, and in light of the AER's view that NIEIR's forecasts (subject to some qualifications) are generally robust, the AER considers that a reasonable set of spatial forecasts for CitiPower would be those that reconcile to NIEIR's forecasts in accordance with ACIL Tasman's recommended approach.

Powercor

Powercor prepares maximum demand forecasts for each ZSS through the following steps:

- the most recent actual summer and winter maximum demand at the feeder level is projected forward using an 'underlying' growth rate, which is based on a linear regression of the most recent five years of historic maximum demand, as well as other factors considered by its network planning group, including abnormal weather patterns, local government development plans/zonings and appliance development (for example, air conditioner impact)[116]

- forecasts are then adjusted for expected load increases and decreases in the year they are planned to occur

- adjustments for load transfers caused by network reconfiguration

- feeder forecasts are aggregated, applying diversity factors, to derive ZSS forecasts.[117]

Powercor noted that it seeks to understand and reconcile any significant differences between its internally prepared forecasts and those prepared by NIEIR and VENCorp.[118] Powercor advised that for the purposes of the current review, it made no changes to its forecasts as it considered them to be within a reasonable range of those prepared by NIEIR.[119]

ACIL Tasman noted while Powercor's approach was similar to that used by other DNSPs, its forecasts are particularly reliant on the judgment of its staff.

It also pointed out that Powercor does not explicitly apply weather correction, although this may be assumed in its use of regression in determining underlying

114 CitiPower, *response to questions on non–coincident demand*, 19 February, p. 6.
115 CitiPower, *Regulatory proposal*, p. 32.
116 Powercor, *demand and energy forecast correspondence*, 22 December 2009.
117 Powercor, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 32.
118 ibid., p. 35.
119 Powercor, *Maximum Demand forecasting – Questions for Powercor*, 17 February 2009.

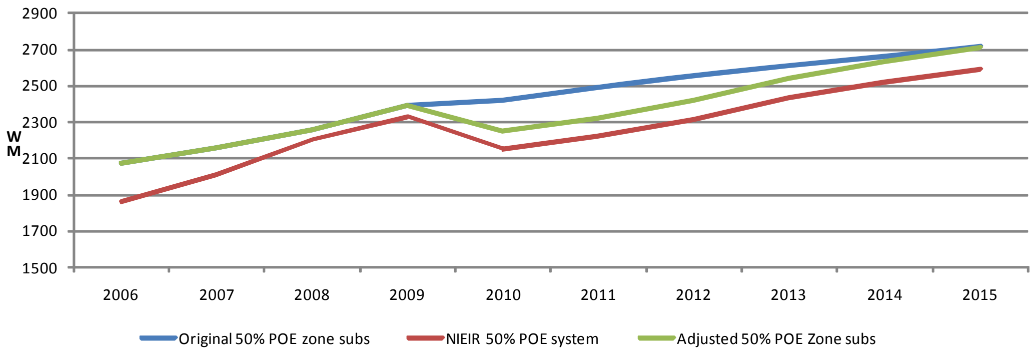
growth rates.[120] ACIL Tasman considered for the more rural areas of Powercor's network, it would be quite plausible that maximum demand is driven by water pumping load rather than temperature sensitive load. However, this assumption was not supported by the materials provided by Powercor in its proposal. Further, the data suggested that Powercor's region experienced a significant increase in maximum demand in 2008 and 2009, and both included hot summer temperatures—this is not consistent with Powercor's view that its load is not temperature sensitive.[121]

ACIL Tasman noted that there is no formal reconciliation procedure between NIEIR's top down forecasts and Powercor's bottom up forecasts, resulting in no account being taken of forecast economic conditions or of the policy interventions expected to influence the growth in maximum demand over the forthcoming regulatory control period.[122]

ACIL Tasman noted that, when compared to NIEIR's forecasts, Powercor's maximum demand forecasts do not appear to adjust sufficiently in 2010 and then proceed to increase more slowly than NIEIR's overall system level forecasts. ACIL Tasman considered this large divergence in 2010 and 2011 as unreasonable, and most likely due to the lack of temperature correction by Powercor in its spatial forecasts.[123] As such, ACIL Tasman concluded Powercor's ZSS forecasts should move in step with NIEIR's system level forecasts. This should reflect NIEIR's macroeconomic and demographic assumptions into the forecast period, and ensure that appropriate temperature correction is incorporated.

ACIL Tasman recommended that Powercor's ZSS forecasts should be reconciled to NIEIR's system level forecasts through the application of a 4.5 per cent diversity factor, as applied by NIEIR.[124] ACIL provided the following chart to illustrate this adjustment.

Figure 5.11 Adjusted Powercor 50 PoE non-coincident zone substation forecasts versus NIEIR 50 PoE system forecasts



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 78.

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120 ACIL Tasman, *Review of maximum demand forecasts*, pp. 68–69.
121 ibid., p. 72.
122 ibid., p. 69.
123 ibid., pp. 71–75.
124 ibid., pp. 77–78.

The AER is concerned that Powercor has implicitly considered the significant divergence between its ZSS forecasts and NIEIR's system forecasts (recognising inherent differences as reflected in historic data) to still be within a reasonable range and not sought to rectify or explain this difference. This is particularly the case for forecasts earlier in the period which clearly indicate issues with weather correction as identified by ACIL Tasman. It should be evident to Powercor's planning staff that 2008 and 2009 were years with unusually high temperature events, hence basing forecast rates of growth from unadjusted demand data from these years would very likely result in unreasonable forecasts at a 50 PoE level. Proper account of such events has evidently been taken into account by NIEIR, where forecasts for 2010 revert to what appear to be 'normal' levels of demand and continue at trend rates of growth. The AER accordingly endorses ACIL Tasman's recommended approach to reconciling the system and ZSS forecasts.

Jemena

Jemena's forecasting methodology involves the following elements:

- The previous year's recorded maximum demand is adjusted for abnormal events and weather normalised to a 50 PoE level. Jemena's weather normalisation process involves fitting a polynomial curve of best fit to a plot of the highest average daily temperature observations that correspond to a range of demand values. These daily observations are also from the most recent year for which data are available.

- The adjusted demand values are projected forward by accounting for expected new large loads and organic growth rates. Growth rates are determined on the basis of judgment by Jemena's planning staff.

- Jemena aggregates its forecasts and compares these with top down forecasts developed by NIEIR at the terminal station level. Jemena adjusts its growth rates to align with that of NIEIR's at the terminal station level.[125]

Jemena noted that while it reconciles its growth rates to those of NIEIR, it chose a different starting point for its forecasts given that NIEIR did not recognise a large number of outages that occurred at the time of the most recent maximum demand (January 2009).[126] Jemena advised that its starting point is subsequently 2.7 per cent higher than NIEIR's starting point.

ACIL Tasman stated while Jemena's spatial forecasting methodology addresses each of the relevant issues and appears to be a reasonable bottom up methodology, there are a number of areas that could potentially be improved.[127] In particular, the approach that is taken to incorporating block and spot loads still leaves room for double counting between these and the organic growth rate. A related issue is that the choice of the initial organic growth rates is subject to the individual judgment of

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[125] Jemena, *Load Demand Forecast Methodology*, 4 February 2010.
[126] Jemena, *Regulatory proposal 2011–15*, 30 November 2009 p. 83.
[127] ACIL Tasman, *Review of maximum demand forecasts*, p. 83.

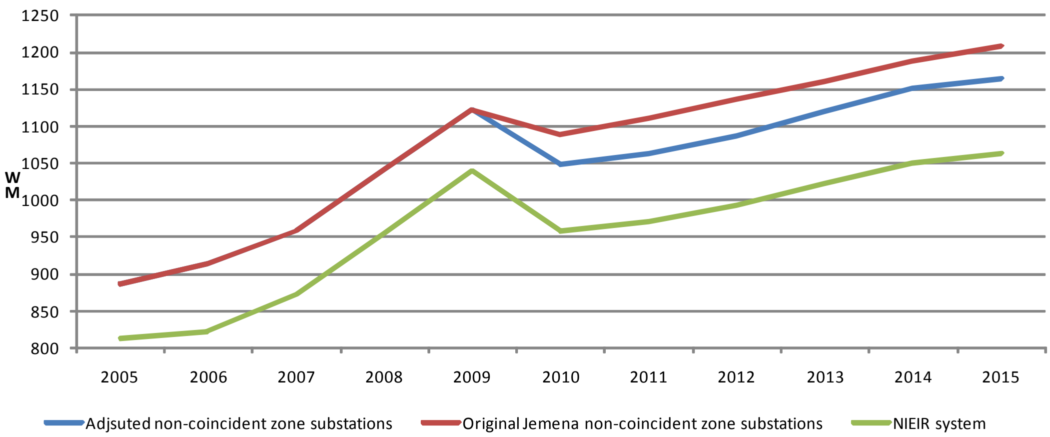
Jemena's system planners which reduces the transparency and repeatability of the process.[128]

ACIL Tasman disagreed with Jemena's decision to adopt its own estimate of a 2009 50 PoE starting point demand in preference to NIEIR's. While it acknowledged that the true maximum demand at the time of this peak would have been higher than that actually supplied, this does not warrant disregarding NIEIR's estimates. ACIL Tasman considered that NIEIR's approach to estimating 50 per cent PoE demand is superior to that of Jemena since NIEIR's approach incorporates a sample of weather and demand observations over many years. ACIL Tasman also noted that from an econometric perspective, relationships observed in data from January 2009 would only be reflective of extreme and infrequent weather events.[129]

ACIL Tasman also expressed some concern about Jemena's choice of assuming a relationship between temperature and demand that follows a polynomial curve, pointing out that this implies that demand would decrease once temperatures rose beyond a certain point.[130]

ACIL Tasman analysed the differences between Jemena's bottom up forecasts and NIEIR's top down forecasts, in each case noting the impact of Jemena's starting point adjustment and its reconciliation of growth rates. Overall it recommended that Jemena's forecasts should be no greater than those prepared by NIEIR, with adjustments made reflecting a constant diversity factor between historic and forecast demand, as illustrated in figure 5.12.

Figure 5.12 Adjusted Jemena non-coincident zone substation forecasts, 50 PoE



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 95.

The AER considers that the information provided by Jemena regarding its forecasting methodology and processes to be far superior to the other DNSPs, including documentation outlining its methodology and also a procedural manual outlining how forecasts are prepared. It also sought independent verification regarding the use of its demand forecasts as a basis for its expenditure proposals.

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128 ibid.
129 ibid., pp. 83–86.
130 ibid., p. 84.

However the AER shares ACIL Tasman's concerns regarding Jemena's decision to use its own adjusted starting point maximum demands over NIEIR's as its methodology is overly reliant on a limited number of observations at the time of the 2009 system peak. VENCorp determined that the January 2009 heatwave in Victoria was equivalent to a 6 per cent PoE, being weather conditions expected to occur one year in every seventeen years.[131] By simply adding the customers involuntarily off supply at the time of the 6 per cent PoE event to the starting point of its 50 per cent PoE maximum demand forecast, Jemena is significantly overstating the impact of the heatwave on its maximum demand projection. Jemena's adjustment contributes to a clear divergence from NIEIR's independently derived forecasts, which are based on a much more stable relationship between temperature and demand, derived from a diverse data set spanning several years. For these reasons, the AER considers that a reasonable set of demand forecasts for Jemena would be reflective of the adjustments recommended by ACIL Tasman.

SP AusNet

SP AusNet provided limited information regarding its spatial forecasting methodology in its regulatory proposal. Its proposal states that it used NIEIR's top down forecasts and then considered the diversity of load at substation level to derive a non-coincident load growth at substation level.[132]

Through discussions with SP AusNet, the AER has ascertained that its forecasting methodology contains the following major elements:

- For each ZSS, the starting point maximum demand is guided by the NIEIR system wide forecast, however judgment is ultimately used, sometimes accounting for the unusually hot 2009 summer affecting these data.

- Historic data on which trends and growth rates are based are not weather corrected, however the potential impact of weather is taken into account when growth rates are determined by planners for each of its three network regions. Similarly, no adjustments are made to historic data for known load transfers given the complexities of doing so.

- Growth rates for each ZSS are determined through the use of judgment, which appears to be mostly based on examining historic annual data (up to 10 years), which may identify long term and shorter term trends through visual inspection. This may also indicate structural breaks, typically based on known load transfers.

- In developing forecasts, regional planners talk to customer service officers linked to each ZSS. These customer service officers obtain information from the local councils and developers within their respective areas.

The aggregated forecasts were compared against NIEIR’s system forecasts, indicating they were a ‘reasonably close’ approximation of the forecast net increase in demand by the end of the forecasting horizon (that is, 2016). This process involves making several adjustments to ensure forecasts are on a comparable basis, for example,

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131 AEMO, *2009 Electricity Statement of Opportunities*, Appendix C, p. C19.
132 SP AusNet, *Electricity Distribution Price Review, Regulatory proposal*, November 2009, p. 85.

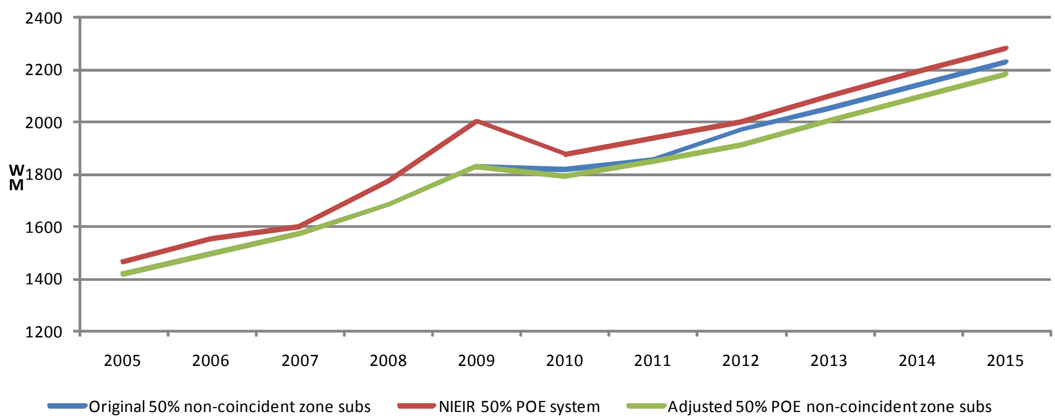
reducing NIEIR's forecasts to reflect forecast load for high voltage customers, and increasing it to account for SP AusNet's assumption that embedded generation would not operate at times of peak demand.

ACIL Tasman did not regard SP AusNet's forecasting methodology as sound, expressing concern that it is not transparent and is unduly reliant on the knowledge and judgment of three regional planners.[133] It noted that there is no systematic adjustment for the influence of temperature on demand, and there is only a general relationship between other objective data and the forecasts.

ACIL Tasman highlighted that no formal reconciliation of the spatial forecasts with an independently derived system level forecast was undertaken. It pointed out that while SP AusNet attempted to roughly match NIEIR’s forecasts by the end of the horizon, there appeared to be significant variations throughout which would be more relevant for the forthcoming regulatory control period.[134]

In examining the differences between SP AusNet's and NIEIR's forecasts, ACIL Tasman noted the average deviation between 2005 and 2009 was 4.4 per cent. On the basis that historical differences should remain constant over time, ACIL Tasman recommended adjusting SP AusNet's ZSS forecasts to maintain this differential into the forecast period. This results in a small reduction to the sum of SP AusNet's ZSS forecasts as illustrated in figure 5.13.

Figure 5.13 Adjusted SP AusNet 50 PoE non-coincident zone substation forecast versus NIEIR 50 PoE system forecasts



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 125.

The AER shares ACIL Tasman's concern that SP AusNet's forecasting methodology is not transparent and overly reliant on judgment. By comparison to the other DNSPs, its process is simplistic and likely to be subject to inconsistencies in how growth rates are developed across its ZSSs. The AER notes that during the review, SP AusNet submitted a document examining its weather correction and spatial demand forecasts.[135] The AER considers that this report does not constitute a formal

133 ACIL Tasman, *Review of maximum demand forecasts*, p. 116.
134 ibid., pp. 116–117.
135 SP AusNet, email to AER staff, 2 March 2010, containing document *SP AusNet Zone Substation demand forecasts*.

documentation of SP AusNet's spatial forecasting methodology as it was only prepared in response to the AER's and ACIL Tasman's questioning of its processes, nor does it substantiate the method's repeatability or transparency.

The AER agrees with ACIL Tasman's recommended adjustments as a means to ensure that the summation of SP AusNet's ZSS forecasts are consistent with NIEIR's more robust and less subjective methods of taking into account weather, economic and other policy impacts on maximum demand.

The AER is also concerned at the approach taken to reconcile its ZSS forecasts to NIEIR's terminal station forecasts, noting the significant divergence during the forthcoming regulatory control period, as illustrated in table 5.21. The AER notes that this data reflects adjustments made by SP AusNet to ensure NIEIR's forecasts are expressed on a comparable basis, as noted above.

Table 5.21 Comparison of sum of SP AusNet zone substation and of NIEIR terminal station forecasts (summer 50 PoE, MW)

	NIEIR	SP AusNet	Difference (MW)	Difference (per cent)
2008–09	1757.4	1757.4	0.0	0.0
2009–10	1744.8	1718.1	–26.7	–1.5
2010–11	1764.8	1800.7	35.9	2.0
2011–12	1827.1	1887.4	60.3	3.3
2012–13	1921.3	1969.3	48.0	2.5
2013–14	2014.1	2054.8	40.7	2.0
2014–15	2105.7	2144.2	38.5	1.8
2015–16	2200.2	2237.3	37.1	1.7

Source: SP AusNet, *Reconciliation of NIEIR and SPA TS Forecasts 27 01 2010*, p. 2; AER analysis.

In noting the resulting differences, SP AusNet pointed out that growth at the terminal station level will be a little lower than the forecast growth at ZSSs due to diversity.[136] This statement is valid with respect to the absolute level of demand, but not with respect to growth rates which should be consistent over time. This fact is implicitly recognised by Jemena and United Energy who reconcile their bottom up growth rates with NIEIR's top down rates. SP AusNet's forecasts presume a higher rate of growth in its ZSS forecasts earlier in the regulatory control period, having the potential effect of triggering investments ahead of the time otherwise implied by NIEIR's forecasts. ACIL Tasman's recommendations seek to maintain the historic diversity observed between SP AusNet's and NIEIR's actual demand data through to their forecasts, which the AER considers is necessary in producing reasonable forecasts.

136 SP AusNet, *Reconciliation of NIEIR and SPA TS Forecasts* 27 01 2010, p. 2.

United Energy

United Energy's regulatory proposal (for example see chapter 13) did not clearly describe its methodology for preparing maximum demand forecasts for its ZSSs. Through discussions with United Energy subsequent to lodging its proposal, the AER understands United Energy's ZSS forecasts are developed as follows:

- the most recent summer maximum demand is weather corrected to a 10 PoE using weighted average daily temperature data (a higher weighting is applied to daily maximum temperatures) and also adjusted for 'network abnormalities'
- these demands are then projected forward, reflecting large known projects expected to arise and 'organic' growth which reflects experience and judgment for the particular area
- each ZSS demand is multiplied by a diversity factor then aggregated to create a system level forecast
- the growth rate (year on year change) of this aggregated forecast is compared to NIEIR's system forecast. Any differences in growth rates are removed from United Energy's ZSS forecasts in proportion to each ZSS's contribution to system maximum demand
- each ZSS forecast is reviewed again based on judgment, with further adjustments potentially applied (while still maintaining consistency between United Energy's and NIEIR's growth rates).

ACIL Tasman pointed out that United Energy's use of weighted average temperatures in its weather correction methodology is consistent with its view that daily maximum temperatures have a greater influence on maximum demand. It also noted that United Energy's practice of reconciling the growth rates of its aggregated ZSS forecasts to NIEIR's system forecast is preferable to no reconciliation at all.[137]

However, ACIL Tasman noted that United Energy's forecasts are taken from a different starting point than NIEIR's, and accordingly the ZSS forecasts appear to be disconnected from the system level forecasts.[138]

ACIL Tasman presented analysis which indicates United Energy's terminal station forecasts grow at a slightly faster rate than NIEIR's system forecasts. Similarly, the difference between NIEIR's system forecasts and the sum of United Energy's ZSS forecasts (that is, ZSS diversity factors) also tend to increase over the forecast period.[139] ACIL Tasman considered that there was no valid reason for this to occur, and recommended adjustments to maintain consistency between United Energy's ZSS forecasts and its system level forecasts.[140] Such adjustments are relatively minor, and are listed in table 5.26.

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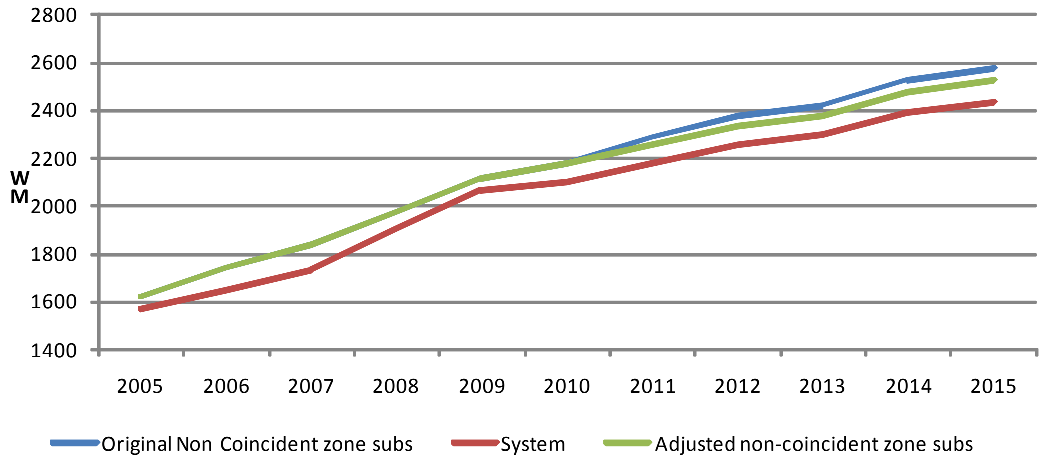
[137] ibid., pp. 100–101.
[138] ibid., p. 101.
[139] ibid., pp. 104–105.
[140] ibid., p. 106.

Figure 5.14 Adjusted United Energy non-coincident zone substation forecasts, 10 PoE



Source: ACIL Tasman, *Review of maximum demand forecasts*, p. 110.

The data provided by United Energy has not allowed the AER to verify the validity of its claim that the sum of its diversified (that is, coincident) ZSS forecasts grows at the same rate as NIEIR's system wide forecasts. The examination of diversity factors by ACIL Tasman indicates that this may actually not be the case. The differences in starting points used by NIEIR and United Energy also indicate that United Energy may not be giving appropriate consideration to the abnormal temperature conditions underlying the most recent (2009) observed maximum demand when preparing its forecasts.

Overall, while the divergence between United Energy's and NIEIR's forecasts is small in comparison to the other DNSPs, the AER regards NIEIR's forecasts as generally reasonable and thus endorses ACIL Tasman's recommended adjustment approach.

AER conclusion—spatial forecasts

In agreeing to ACIL Tasman's recommended adjustments, the AER has sought to reconcile the Victorian DNSPs' ZSS forecasts to NIEIR's top down forecasts, noting the average historical diversity between the two. The AER considers that the increasing diversity reflected in the Victorian DNSPs' forecasts reflects their overstating demand at particular ZSSs for the forthcoming regulatory control period. In the absence of an alternative method, the AER has translated the required reductions to the aggregated ZSS forecasts by targeting specific ZSS which exhibit a significant divergence from the average forecast rate of growth for all ZSSs combined, or where the forecast rate of growth diverges from the historic rate at that ZSS.[141] The AER has also been mindful of taking into account of the life cycle of specific ZSS, as recommended by ACIL Tasman, whereby certain network regions may legitimately be growing faster than average as they are only recently established. For this reason the AER has only selected ZSSs which also have been operational from at least 2001. The AER allocated the total required reduction to each ZSS in proportion to their maximum demand.

[141] A threshold of 1.5 per cent above the average of all ZSS combined was selected, and 1.0 per cent with respect to the ZSS's own historic average.

By applying this approach, the AER has made adjustments for the DNSPs' ZSS as listed in tables 5.22 to 5.26. The AER notes that these ZSS forecasts have not been mechanistically taken into account in its or its consultant's assessment of the Victorian DNSPs' reinforcement capex programs.

The AER acknowledges that the method of arriving at these adjustments may not accurately reflect the specific shortcomings in the Victorian DNSPs' forecasting methods which have given rise to discrepancies with NIEIR's forecasts. However, the AER considers this to be a reasonable approach in the absence of better alternatives to ensure the Victorian DNSPs' spatial forecasts reconcile to NIEIR's system forecasts. For these reasons, the AER considers the adjusted ZSS forecasts are reflective of a reasonable expectation of demand growth over the forthcoming regulatory control period. The Victorian DNSPs will have an opportunity in their revised proposals to propose an alternative method of ensuring an appropriate reconciliation with NIEIR's top down forecasts, which the AER considers to be fundamental in producing reasonable spatial demand forecasts.

Table 5.22 AER conclusion—reductions to non-coincident zone substation forecasts—CitiPower (MW)

	2009	2010	2011	2012	2013	2014	2015
Sum of ZSS forecast	1534.1	1482.7	1539.2	1580.9	1649.3	1691.0	1734.1
ACIL reduction	–	35.9	74.2	71.9	76.3	88	107.1
Difference (per cent)	–	2.4	4.8	4.5	4.6	5.2	6.2
Targeted ZSSs							
BSBQ	31.8	34.4	39.1	40.3	42.5	43.7	44.9
DA	30.0	31.1	33.2	35.3	37.4	39.5	41.7
E	13.9	8.0	8.1	8.2	8.4	8.5	8.6
FR	53.9	56.0	57.1	58.3	62.3	63.4	64.6
JA	94.4	97.7	104.8	111.3	127.7	134.3	140.9
LS	18.4	18.7	19.2	19.7	20.3	20.8	21.3
MP	109.8	116.3	119.0	121.4	129.1	131.5	133.9
PM	14.7	14.9	15.9	17.0	18.0	19.0	20.1
RP	11.4	10.6	11.0	11.1	11.2	11.2	11.3
TP	6.4	10.0	10.1	10.2	10.3	10.4	10.4
AER adjusted forecasts							
BSBQ	31.8	31.3	32.2	33.6	35.6	35.7	35.2
DA	30.0	28.3	27.3	29.4	31.3	32.3	32.7
E	13.9	7.2	6.7	6.9	7.0	6.9	6.8
FR	53.9	50.9	47.0	48.6	52.1	51.9	50.7
JA	94.4	88.9	86.2	92.8	106.8	109.8	110.6
LS	18.4	17.0	15.8	16.5	17.0	17.0	16.7
MP	109.8	105.8	97.8	101.2	108.0	107.5	105.1
PM	14.7	13.6	13.1	14.1	15.1	15.6	15.8
RP	11.4	9.6	9.0	9.2	9.3	9.2	8.9

TP	6.4	9.1	8.3	8.5	8.6	8.5	8.2

Source: All DNSPs, RIN template 6.3/ response to questions non-coincident MD; AER analysis.

Table 5.23 AER conclusion—AER reductions to coincident zone substation forecasts—Powercor (MW)

	2009	2010	2011	2012	2013	2014	2015
Sum of ZSS forecast	2391.0	2418.6	2488.4	2557.0	2609.8	2658.8	2716.4
ACIL reduction	–	171.0	161.4	120.0	40.8	–10.2	–30.6
Difference (per cent)	–	7.1	6.5	4.7	1.6	–0.4	–1.1
Targeted ZSSs							
AC	6.9	7.2	7.5	10.0	10.3	10.6	11.0
AL	20.6	21.1	21.4	21.8	22.1	22.5	22.9
BAS	67.8	67.3	74.6	84.6	86.2	87.7	89.4
BCC	11.5	13.5	15.0	15.0	15.0	15.0	15.0
BBD	11.8	15.2	16.9	18.1	19.0	19.4	19.4
BGL	1.7	2.0	2.0	2.0	2.0	2.0	2.0
CLC	41.1	43.1	45.9	47.4	48.3	49.3	50.2
CPL	11.5	11.5	11.5	12.5	12.5	12.5	12.5
CRO	28.5	30.8	31.1	31.4	31.8	32.1	32.4
DDL	50.9	52.5	54.7	58.3	60.4	64.2	66.0
DLF	7.6	20.1	23.6	24.7	25.0	25.1	25.2
ECA	38.1	37.6	38.1	38.6	39.1	39.6	40.2
FDN	12.0	12.0	12.0	12.0	12.0	12.0	12.0
GB	19.5	19.6	20.1	21.2	22.6	23.5	27.2
GCY	37.3	41.7	42.3	42.7	43.1	43.5	45.7
HCP	5.1	5.1	5.1	5.1	5.1	5.1	5.1
KRT 1 & 2	21.8	22.2	22.6	23.0	23.4	23.9	24.3
KYM	31.0	30.6	30.8	31.1	31.3	31.6	31.9
LVN	62.2	71.6	73.7	75.8	78.0	80.3	82.6
SCI/A	28.2	28.2	30.0	30.0	33.0	33.0	33.0
WIN	6.5	6.6	6.6	6.7	6.8	6.8	6.9
WMN	11.4	13.8	16.1	18.0	19.6	21.0	22.0

WND	55.9	57.9	60.1	62.2	64.5	66.8	69.3
WPD	67.3	71.3	76.5	81.9	86.9	89.0	91.8
AER adjusted forecasts							
AC	6.9	5.4	5.8	8.4	9.8	10.8	11.4
AL	20.6	16.0	16.7	18.4	21.0	22.8	23.7
BAS	67.8	50.9	58.3	71.5	81.8	88.8	92.6
BCC	11.5	10.2	11.7	12.7	14.2	15.2	15.5
BBD	11.8	11.5	13.2	15.3	18.1	19.6	20.1
BGL	1.7	1.5	1.6	1.7	1.9	2.0	2.1
CLC	41.1	32.6	35.9	40.1	45.9	49.9	52.1
CPL	11.5	8.7	9.0	10.6	11.9	12.7	13.0
CRO	28.5	23.3	24.3	26.6	30.1	32.5	33.6
DDL	50.9	39.7	42.7	49.2	57.3	65.0	68.4
DLF	7.6	15.2	18.5	20.9	23.7	25.4	26.1
ECA	38.1	28.4	29.8	32.6	37.1	40.1	41.6
FDN	12.0	9.1	9.4	10.1	11.4	12.1	12.4
GB	19.5	14.9	15.7	17.9	21.4	23.8	28.2
GCY	37.3	31.5	33.1	36.1	40.9	44.0	47.3
HCP	5.1	3.9	4.0	4.3	4.8	5.2	5.3
KRT 1 & 2	21.8	16.8	17.6	19.4	22.2	24.1	25.2
KYM	31.0	23.1	24.1	26.3	29.7	32.0	33.0
LVN	62.2	54.2	57.6	64.1	74.0	81.3	85.7
SCI/A	28.2	21.3	23.4	25.3	31.3	33.4	34.2
WIN	6.5	5.0	5.2	5.7	6.4	6.9	7.1
WMN	11.4	10.5	12.6	15.2	18.6	21.3	22.8
WND	55.9	43.8	46.9	52.5	61.2	67.7	71.8
WPD	67.3	53.9	59.8	69.2	82.5	90.1	95.1

Source: All DNSPs, RIN template 6.3/ response to questions non-coincident MD; AER analysis.

Table 5.24 **AER conclusions—AER reductions to non-coincident zone substation forecasts—Jemena (MW)**

	2009	2010	2011	2012	2013	2014	2015
Base ZSS forecast	1122.2	1088.2	1110.9	1135.9	1161.0	1188.1	1208.6
ACIL reduction	–	39.3	43.9	39.9	27.0	20.1	24.6
Difference (per cent)	–	3.6	4.0	3.5	2.3	1.7	2.0
Targeted ZSSs							
APF	10.4	10.4	10.4	10.4	10.4	10.4	10.4
BY	38.4	35.9	50.1	51.7	52.7	53.7	54.4
CN	65.2	68.3	70.3	71.8	73.6	75.3	76.2
CS	39.3	39.6	41.0	42.3	45.2	47.5	48.7
EP A	19.0	19.4	19.6	19.9	20.1	20.4	20.6
EP B	13.3	13.3	13.5	13.7	13.8	14.0	14.2
FE	29.9	29.0	27.8	28.5	34.7	35.4	35.9
MB	2.6	2.6	2.7	2.7	2.7	2.7	2.8
NT	38.6	32.7	46.7	48.0	48.7	49.3	49.9
SA	5.0	5.1	5.1	5.2	5.3	5.4	5.4
ST	71.8	74.8	80.2	85.0	89.0	92.9	95.3
WT	1.7	1.9	2.2	2.7	2.9	3.1	3.1
AER adjusted forecasts							
APF	10.4	9.2	9.1	9.3	9.7	9.9	9.8
BY	38.4	31.6	44.2	46.3	49.2	51.0	51.2
CN	65.2	60.2	61.9	64.3	68.6	71.6	71.8
CS	39.3	34.9	36.2	37.9	42.1	45.2	45.9
EP A	19.0	17.1	17.3	17.8	18.8	19.4	19.4
EP B	13.3	11.7	11.9	12.2	12.9	13.3	13.4
FE	29.9	25.6	24.5	25.5	32.3	33.7	33.8

MB	2.6	2.3	2.3	2.4	2.5	2.6	2.6
NT	38.6	28.8	41.1	43.0	45.4	46.9	47.0
SA	5.0	4.5	4.5	4.7	4.9	5.1	5.1
ST	71.8	65.9	70.7	76.1	83.0	88.3	89.7
WT	1.7	1.7	2.0	2.4	2.7	2.9	2.9
MB	2.6	2.3	2.3	2.4	2.5	2.6	2.6
NT	38.6	28.8	41.1	43.0	45.4	46.9	47.0
SA	5.0	4.5	4.5	4.7	4.9	5.1	5.1
ST	71.8	65.9	70.7	76.1	83.0	88.3	89.7
WT	1.7	1.7	2.0	2.4	2.7	2.9	2.9

Source: All DNSPs, RIN template 6.3/ response to questions non-coincident MD; AER analysis.

Table 5.25 AER conclusion—AER reductions to non-coincident zone substation forecasts—SP AusNet (MW)

	2009	2010	2011	2012	2013	2014	2015
Base ZSS forecast	1828.7	1820.5	1856.4	1967.5	2051.8	2139.7	2231.3
ACIL reduction	–	28.2	–1.6	39.5	19.8	14.7	19.3
Difference (per cent)	–	1.5	–0.1	2.0	1.0	0.7	0.9
Targeted ZSSs							
Lilydale	81.4	81.3	86.2	91.3	96.8	102.6	108.8
Mt Beauty	9.0	9.0	9.4	9.7	10.0	10.3	10.6
Murrindindi	0.2	0.2	0.2	0.2	0.2	0.3	0.3
Mansfield	18.5	18.5	18.9	19.3	19.7	20.1	20.5
Pakenham	48.0	49.9	39.9	43.5	47.0	50.7	54.8
Warragul	55.2	54.3	58.6	62.8	67.1	71.4	75.7
Wonthaggi	54.0	54.0	54.0	54.0	54.0	54.0	54.0
AER adjusted forecasts							
Lilydale	81.4	72.7	86.7	78.5	90.3	97.7	102.3
Mt Beauty	9.0	8.1	9.5	8.3	9.3	9.8	10.0
Murrindindi	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Mansfield	18.5	16.5	19.0	16.6	18.4	19.1	19.2
Pakenham	48.0	44.7	40.1	37.4	43.8	48.3	51.5
Warragul	55.2	48.5	58.9	54.0	62.6	68.0	71.2
Wonthaggi	54.0	48.3	54.3	46.4	50.4	51.4	50.8

Source: All DNSPs, RIN template 6.3/ response to questions non-coincident MD; AER analysis.

Table 5.26 AER conclusion—AER reductions to zone substation forecasts—United Energy (MW)

	2009	2010	2011	2012	2013	2014	2015
Base ZSS forecast	2117.3	2175.8	2285.1	2374.2	2422.4	2528.1	2552.8
ACIL reduction	–	–2.0	19.0	22.0	16.0	19.0	19.0
Difference (per cent)	–	–0.1	0.8	0.9	0.7	0.8	0.7
Targeted ZSSs							
CM	28.5	29.5	30.9	32.2	32.9	34.6	35.4
CRM	60.0	73.6	75.3	76.8	77.6	79.6	80.5
DSH	63.4	66.3	70.2	73.3	74.9	78.3	80.0
DVY	67.4	70.3	76.5	81.8	85.1	92.5	95.4
EW	19.0	22.4	23.2	24.0	24.4	25.4	25.9
GW	73.4	74.4	76.7	78.9	80.2	83.0	84.3
HT	52.3	56.5	58.4	60.1	61.1	63.3	64.3
LD	45.4	48.3	52.1	53.8	54.7	56.9	57.9
M	34.9	36.7	40.3	41.0	41.3	42.1	42.4
NO	44.4	49.5	52.0	54.3	55.7	58.9	60.4
OE	13.2	14.0	14.4	14.7	14.9	15.3	15.5
RBD	36.4	39.0	40.8	42.5	43.5	45.7	46.7
SS	45.0	46.8	48.4	49.8	50.6	52.5	53.3
STO	26.1	32.4	35.6	36.7	37.3	38.7	39.4
SV	50.7	51.7	60.9	65.9	66.9	68.9	69.8
AER adjusted forecasts							
CM	28.5	29.6	30.1	31.3	32.3	33.8	34.6
CRM	60.0	73.8	73.4	74.6	76.1	77.8	78.7
DSH	63.4	66.5	68.4	71.3	73.4	76.6	78.2
DVY	67.4	70.5	74.6	79.6	83.4	90.4	93.2

EW	19.0	22.5	22.7	23.3	23.9	24.8	25.3
GW	73.4	74.6	74.8	76.7	78.6	81.1	82.4
HT	52.3	56.7	56.9	58.4	59.9	61.9	62.9
LD	45.4	48.4	50.8	52.3	53.6	55.6	56.6
M	34.9	36.8	39.3	39.8	40.5	41.1	41.5
NO	44.4	49.6	50.7	52.8	54.6	57.5	59.0
OE	13.2	14.1	14.0	14.3	14.6	14.9	15.1
RBD	36.4	39.1	39.8	41.3	42.6	44.7	45.7
SS	45.0	47.0	47.2	48.4	49.6	51.3	52.1
STO	26.1	32.5	34.7	35.6	36.5	37.8	38.5
SV	50.7	51.8	59.4	64.1	65.5	67.3	68.3

Source: All DNSPs, RIN template 6.3/ response to questions non-coincident MD; AER analysis.

5.6.7 TOU tariff impacts

This section examines the impact of advanced metering infrastructure (AMI) or ‘smart meters’ as a policy accounted for by NIEIR and the Victorian DNSPs in developing their forecasts. This policy reflects the Victorian Government's 2006 decision to install AMI for all customers consuming less than 160 MWh per year by 31 December 2013.

AMI allows DNSPs and retailers to monitor a customer's energy usage at half hourly intervals and provides for the implementation of TOU tariffs. TOU tariffs are intended to provide clearer pricing signals to users about the cost of network usage at peak and off peak times, resulting in potential changes in consumption patterns and deferral of network investments. The Victorian AMI specifications are compatible with other technologies (for example, in home displays, controllable thermostats, etc.) to further assist customers reduce their consumption at the time of network peaks.

Much of the impact of AMI and TOU tariffs revolves around assumptions with respect to price elasticity. The demand for electricity is a derived demand as it is an input in the consumption of electrical appliances. In general, the demand for electricity is relatively inelastic in the short run as customers can only modify their usage through behavioural changes rather than changing their appliances and housing characteristics. In the long run customers are able to purchase more efficient appliances or reduce their reliance on space heating/ cooling through products such as home insulation.

Substitution elasticity is also a relevant consideration under TOU tariffs.[142] The substitution elasticity measures the relationship between a change in the relative price of two substitutes (for example, peak and off peak electricity) and the change in relative quantities demanded. Therefore, if the price of one good becomes relatively higher to the substitute, the customer will change the way in which they consume the goods/service (for example, if peak prices increase relative to off peak prices, the customer will shift its consumption from peak periods to off peak periods).

Victorian DNSP regulatory proposals

The Victorian DNSPs have relied on NIEIR to forecast impacts due to implementation of AMI and TOU for maximum demand and energy consumption, except for SP AusNet in the case of energy consumption where it estimated its own impacts.

NIEIR noted the elasticity of demand as a ‘key indicator’ for projections of usage.[143] NIEIR listed the number of smart meters being rolled out across Victoria and summarised a number of pilot studies conducted in different countries and decades.[144] In discussions with the AER, NIEIR has indicated that no assumption on own-price and substitution elasticities has been applied on the impacts of maximum demand. Rather, it assumed that maximum demand will be reduced by a fixed percentage for those customers switching to a smart meter.

SP AusNet modelled the impact of AMI on energy consumption using:

- the Net System Load Profile (NSLP) to determine the split between peak, shoulder and off peak energy consumption
- the NSLP to model the specific impact that the price is expected to have based upon the old and new indicative price structures for small customers (based upon the tariff components within each tariff classes)
- energy consumption data from NIEIR, which excludes the AMI policy impact is used to calculate the average consumption per customer for that customer class[145]
- forecast numbers of customers switching to AMI, as per the Victorian Government's rollout schedule
- assumed values for the own-price and cross-price elasticity of demand.[146]

These factors were combined to adjust the average consumption per forecast customer switched on to AMI (by a percentage estimated by applying prices and elasticities to

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142 This is to be distinguished from a cross–price elasticity which measures the relationship between the relative price of a substitute or complementary good and the relative change in demand for the other good.

143 For example see NIEIR, *Maximum demand forecasts for SP AusNet*, p. 72.

144 ibid., pp. 72–74.

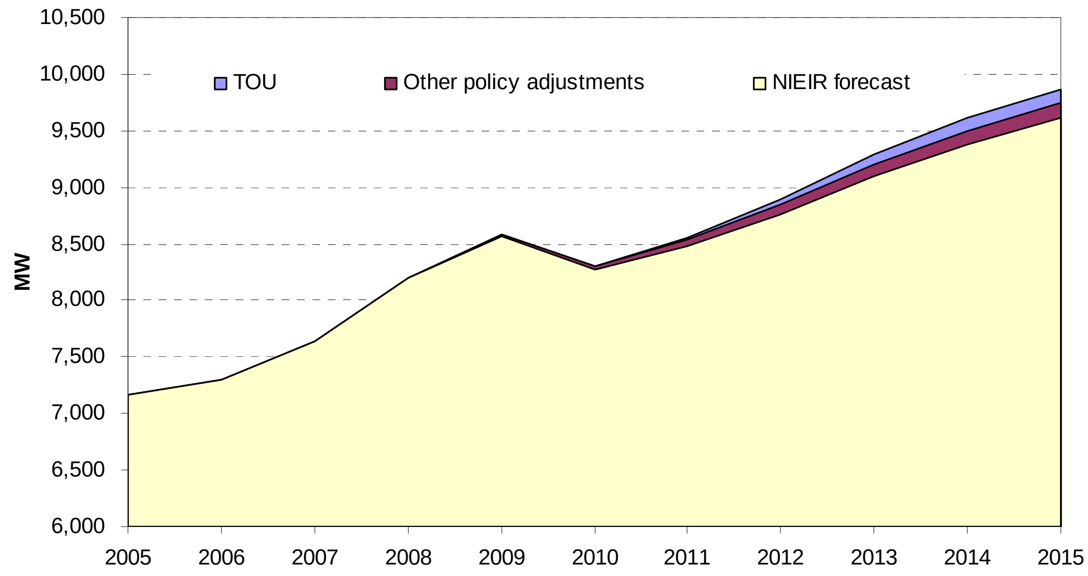
145 Discussions between staff from the AER and SP AusNet revealed that SP AusNet used NIEIR adjusted numbers in the regulatory proposals. This resulted in a double counting of the reduction arising from AMI which the AER has taken into account in making its decision.

146 SP AusNet, *Regulatory proposal*, pp. 91–93.

the NSLP), which was then multiplied by the number of customers on AMI to provide a forecast of the impact of AMI on SP AusNet's energy consumption forecasts.

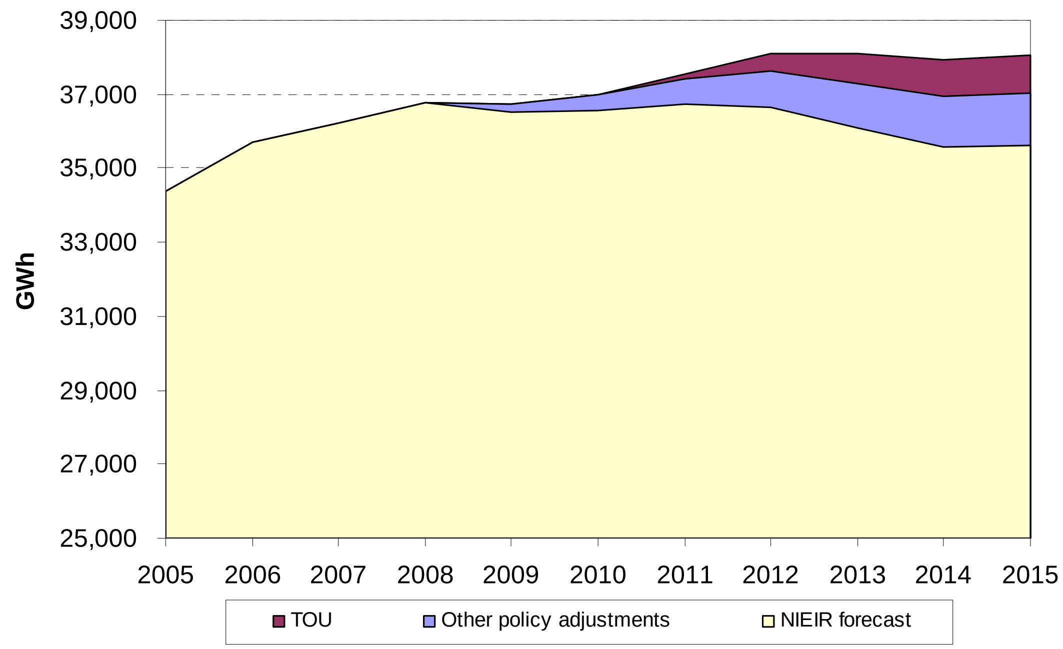
Figures 5.20 and 5.21 illustrate the impact of the TOU adjustments on the combined forecasts for all Victorian DNSPs. Other policy adjustments are listed for comparative purposes.

Figure 5.15 NIEIR's forecast cumulative policy adjustments (maximum demand)



Source: AER analysis, DNSP regulatory proposals and NIEIR maximum demand reports tables 6.3, 6.6, 10.4 and 10.6.

Figure 5.16 NIEIR's forecast cumulative policy adjustments (energy consumption)



Source: AER analysis, DNSP regulatory proposals and NIEIR energy consumption reports tables 6.2 and 6.5.
Note: Only NIEIR TOU impacts used (SP AusNet's further adjustments excluded to avoid double counting).

Submissions

Many submissions on the Victorian DNSPs' proposals commented on the issue of AMI and TOU tariffs.[147] Specifically, the submissions focussed on the:

- lesser impact on maximum demand forecasts and greater impact on energy consumption forecasts
- impediments to customer response to the introduction of TOU
- price elasticity assumptions used in the modelling.[148]

With respect to the assumed customer response to TOU pricing, stakeholders argued that the following three hurdles must be cleared in order for price signals to be effective:

- DNSP must send the price signal (which must not be distorted in communication)
- customer must receive the price signal (in a timely manner), understand it and see it as a message to modify its behaviour
- customer must act on the price signal.[149]

Stakeholders expressed doubts over the presence of these elements to be satisfied to the extent assumed by the Victorian DNSPs over the forthcoming regulatory control period. In particular:

- retailers may package network prices with other costs (for example, energy prices which may peak at different times) in a form such that price signals are diluted
- specific customer groups may be unable to respond to price signals, including low income earners and business customers with budgetary constraints (with respect to obtaining systems capable of responding to TOU)
- other customers may simply not understand the complexities of electricity bills or know how to respond.[150]

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[147] CUAC, *Submission to the AER*, 17 February 2010; EUAA, *Submission to the AER*, 12 February 2010; AIG, *Submission to the AER*, 12 February 2010; VECCI, *Re: AER review of the Victorian distributors' regulatory proposals*, 19 February 2010; Origin Energy, *Submission to the AER*, 11 February 2010.

[148] For example see, Origin Energy, *Submission to the AER*, 11 February 2010, p. 5; and EUAA, *Submission to the AER*, 12 February 2010, p. 10.

[149] VECCI, *Submission to the AER*, 19 February 2010, p. 8.

[150] CUAC, *Submission to the AER*, 17 February 2010, p. 3; EUAA, *Submission to the AER*, 12 February 2010, p. 10; AIG, *Submission to the AER*, 12 February 2010, pp. 2–3; VECCI,

The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria (the Minister) submitted that TOU are designed to reduce demand at peak periods. With the rollout due to finish by the end of 2013, the Victorian Government expects that the Victorian DNSPs' peak demand forecasts will be significantly reduced in the latter years of the regulatory control period.[151]

Origin Energy noted that:

- there is little evidence in the Australian context of reductions in energy consumption resulting from the move to interval meters
- it is uncertain whether the meters will lead to a sustained reduction in consumption and, if so, over what period
- the impact of AMI on demand and energy consumption are strongly correlated
- it would be of concern if the impact on peak demand was assumed to be minimal or doubtful, yet the impact on volumes was fully factored in.[152]

Origin Energy noted the rollout schedule and contended even in the most optimistic scenario (where customers enthusiastically embrace the new technology and seek to modify their behaviour) energy consumption is still likely to be less elastic to price in the short run, as certain drivers of customer energy use cannot be changed immediately. [153]

Consultant review

ACIL Tasman noted the following:

- little work has been conducted on forecasting the impact of AMI and TOU on maximum demand, which is reflected in NIEIR's reports for the Victorian DNSPs and the research conducted to date
- in choosing to pursue the AMI rollout, the Ministerial Council on Energy considered smart meters would lead to a reduction in peak demand and thus a deferral of network augmentation
- the incentive to reduce electricity demand comes not from the meter itself but from the tariff that can be charged once the meter is installed
- NIEIR's forecasts reflect the assumption that maximum demand would be reduced by 2 per cent below the level at which it would otherwise have been.[154]

Submission to the AER, 19 February 2010, pp. 9–13; Origin Energy, *Submission to the AER*, 11 February 2010, p. 5.

151 Minister for Energy and Resources, *Re: Submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–15*, February 10 2010, p. 3.

152 Origin, *Submission to the AER*, 11 February 2010, p. 5.

153 ibid., p. 5.

154 ACIL Tasman, *Review of maximum demand forecasts*, pp. 39–44.

ACIL Tasman noted the Victorian Government has announced a moratorium on TOU and there is very limited detail available on the nature of the rollout of TOU.[155] The moratorium amounts to a delay in the impact on demand forecasts.

ACIL Tasman noted a number of factors which are likely to affect customers' response to TOU, such as:

- the literature on TOU suggests the energy elasticities take effect over time and the forthcoming regulatory control period will be halfway complete before AMI is in place
- the results from the trials may overstate the likely benefits, as trials generally do not involve ‘real customers’ in the ‘real world’
- while efforts will be made to provide information on TOU, there is a much larger group receiving AMI, and there is an increased likelihood the message will not ‘get through’ as strongly as it did in trials
- the ‘rebound effect’, where customers become less responsive to TOU over time due to:
  - energy bills being a relatively small amount of disposable income so not worth as much effort to reduce as other things
  - a principal agent problem in households with multiple occupants
  - the issue known to behavioural economists as ‘relativity’, where new prices gradually become ‘normal’
  - the message will be simply be lost over time.
- critical peak pricing (CPP) tariffs initiate a larger response than TOU, however, CPP are only implemented a few times a year and, therefore, it is expected to have a greater impact on maximum demand than energy consumption.[156]

ACIL Tasman considered it was unlikely the tariffs implemented in Victoria will resemble those used in the studies surveyed by the Victorian DNSPs, due to the Victorian Government's response to customers' concerns.[157] Therefore ACIL Tasman considered the demand forecast adjustments proposed by the Victorian DNSPs is likely to be overstated and in light of the uncertainty raised by the moratorium, and recommends that the AER reject any reduction in demand forecasts due to TOU.[158]

AER considerations

Overall, the AER considers the Victorian DNSPs have not provided sufficient information to demonstrate that the effect on maximum demand arising from AMI

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155 ACIL Tasman, *Review of electricity sales and customer numbers*, p. 56.
156 ACIL Tasman, *Review of maximum demand forecasts*, pp. 39–44; ACIL Tasman, *Review of electricity sales and customer numbers*, pp. 41–57.
157 ACIL Tasman, *Review of electricity sales and customer numbers*, pp. 51–52.
158 ibid., p. 56.

should be significantly different from that on energy forecasts. NIEIR and the Victorian DNSPs appear to have simply presumed that, from the day AMI is installed, affected customers would significantly reduce their energy consumption except for a very limited period of time each year where temperatures reach their highest. While this is a plausible outcome, it has not been demonstrated as being a realistic expectation for all customers over the timeframes suggested and to the extent quantified in the proposals. The analysis underlying the regulatory proposals is also simplistic, and by apparent coincidence it favours the Victorian DNSPs by predicting a very small reduction to maximum demand and a large reduction to energy consumption.

Given the uncertainty surrounding all of the factors that make up AMI and TOU tariff impacts (that is, the Victorian Government's moratorium, the ability to send price signals, potential compensation to customers, the phasing in of TOU and other complexities), the AER considers it reasonable to assume that there will be no material impact on maximum demand and energy consumption over the forthcoming regulatory control period. Moreover, any impact is likely to arise in the latter years of the period where it cannot be predicted with any reasonable degree of accuracy.

This section examines the following issues in further detail:

- consistency in approach between maximum demand and energy consumption
- impediments to the implementation of AMI and TOU
- uncertainty around AMI and the introduction of TOU tariffs
- the examination of price elasticities and other assumptions used.

Consistency in approach between maximum demand and energy consumption

NIEIR has conducted the analysis with respect to the impact of AMI and TOU on maximum demand. Based upon discussions with NIEIR and the Victorian DNSPs it appears a simplistic assumption (2 per cent reduction for users with smart meters) about the impact on maximum demand from AMI and TOU has been made. The AER contrasts NIEIR’s approach in maximum demand with the approach NIEIR and SP AusNet have taken with energy consumption. The AER observes the energy consumption analysis has involved:

- an examination of the literature to develop a range of plausible elasticities (own-price and substitution elasticities)
- a selection of either a set of values over time (or a single value) for the forthcoming regulatory control period
- making assumptions about the TOU that are expected to prevail over the forthcoming regulatory control period
- in SP AusNet’s regulatory proposal, assumptions relating to usage based upon VENCorp’s Net System Load Profile, and the proportion of the retail bill which comprises the network tariff.

The AER has concerns over the lack of a considered approach adopted when examining the impact of AMI on maximum demand. The selection of 2 per cent appears to be arbitrary and no information was provided by NIEIR or the Victorian DNSPs to support the adjustment. The AER considers at the very least an examination of the available literature, consistent with NIEIR's and SP AusNet's approach for energy consumption, would be a reasonable approach to take. For example using a paper which NIEIR quotes in its reports, the Brattle Group noted the Colorado Xcel Energy TOU Pilot experienced an 11 per cent reduction in demand and the Ontario Energy Board's Smart Price Pilot observed a 2 per cent reduction.[159] That said, the AER considers a degree of caution should be taken when considering the outcomes of trials (as discussed below).

Further, although the weight of studies to date have examined the impacts of AMI and TOU on energy consumption, the AER would expect that that some inferences could be drawn from the studies which examined the price elasticity of peak consumption. Also, it is worth noting SP AusNet referred to a study conducted by Monash University which attempts to estimate a demand elasticity for maximum demand in South Australia, yet little or no attempts were made to consider this study (and others which examined peak consumption) in the context of the impacts of AMI and TOU on maximum demand. [160]

Due to the lack of documentation relating to NIEIR's selection of 2 per cent, it is unclear to the AER what PoE temperature conditions were assumed when the 2 per cent adjustment was determined. While the AER is cognisant that maximum demand may be more sensitive to temperature rather than TOU, weather impacts are typically in the context of a 50 PoE temperature (approximately an average of 29 degrees). Contrary to NIEIR's assumption that customers would (largely) ignore prices at such temperatures and activate air conditioning as per normal, a more plausible outcome is that, in the light of education around TOU tariffs, customers would choose to adjust the thermostat on their air conditioners to a higher temperature (for example, 23 degrees instead of 21 degrees Celsius) and this is likely to result in a reduction in maximum demand.

Such behavioural responses are critical in predicting the impact of TOU pricing however are subject to considerable uncertainty. In any case the AER considers it unrealistic for NIEIR and the Victorian DNSPs to expect such disproportionate reductions in overall electricity consumption (of approximately 2.9 per cent in 2015) and maximum demand (1.2 per cent).

Impediments to the implementation of AMI and TOU

The AER notes that it has received a number of submissions from stakeholders and advice from ACIL Tasman, which outline the limitations upon the effectiveness of AMI and TOU tariffs, such as:

- the ability of DNSPs to send price signals to customers

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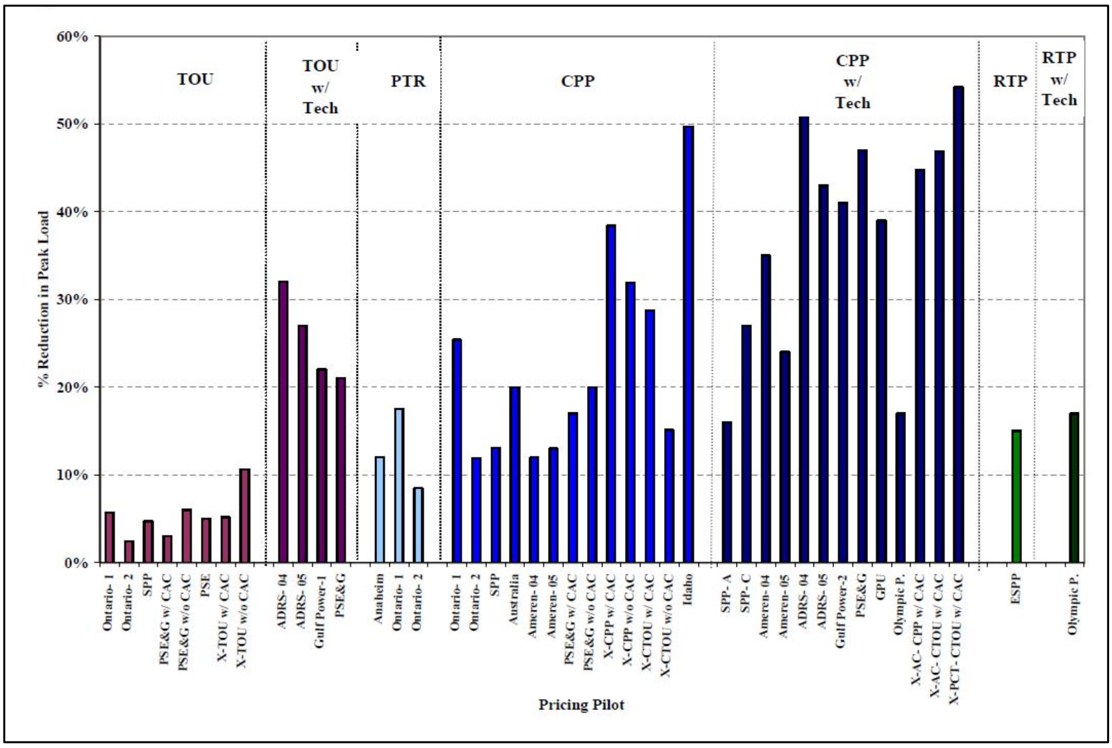
159 Brattle Group, *Household response to dynamic pricing of electricity—A survey of the experimental evidence*, 10 January 2009, pp. 19 and 37.

160 SP AusNet, *Regulatory proposal*, p. 93.

- differences between the structure of network tariffs and retail tariffs
- rebound effects which make demand more inelastic over time
- the ability for customers to respond to the price signal
- policy responses to TOU in Victoria.

The Brattle Group study, which NIEIR refers to in its reports, illustrates customer responses can vary significantly depending on the pricing arrangements and delivery mechanism used. Figure 5.22 illustrates the impact observed in a number of studies.

Figure 5.17 Reduction in peak load—Brattle Group Study summary



Source: Brattle Group, *Household response to dynamic pricing of electricity—A survey of experimental evidence*, 10 January 2009, p. 41.

Figure 5.22 summarises the impact on peak load (where it is expected TOU is likely to have the greatest impact). The AER observes TOU, without the use of enabling technologies or critical peak pricing had the smallest impact. This is consistent with the views expressed in stakeholder submissions. In viewing these results, the AER highlights comments by ACIL Tasman that caution should be taken when examining the results of pilot studies conducted over different decades and jurisdictions. This notwithstanding, figure 5.22 illustrates the importance of providing customers with enabling technologies in order to receive the price signal.

The AER notes it has received a submission from VECCI which raised concerns over the method of sending price signals (for example, SMS) and the individual who will receive the signal (for example, franchisor rather than the franchisee).[161] The AER considers the method by which price signals are transmitted is uncertain and will have short run and long run implications. For example, if an information campaign and fridge magnets are used to make customers aware of TOU tariffs, it may result in a short term response. However, over time existing customers may forget this information and new customers may not be aware of the implications of TOU on electricity bills.

NIEIR and the Victorian DNSPs have not assumed that price signals would be delivered to customers through the use of in home displays (IHD). Other types of enabling technologies such as thermostat and air conditioner controls were also not assumed to take effect over the forthcoming regulatory control period. Hence price signals delivered through retail billing arrangements is the only mechanism by which AMI is assumed to take effect in the short to medium term.

The AER agrees with VECCI's view that although most energy retailers appear to pass through the network charges, there remains scope for the retailer to modify those signals to better reflect the costs of its own business.[162] In other words, the TOU periods used by the retailer may not necessarily align with the same periods used by the DNSP (for example, due to a different peak period for wholesale electricity costs), which would distort the signal to the customer. Furthermore, as retailers sell electricity to customers serviced by different DNSPs, the different network price signals are likely to be diluted when homogenous retail tariffs are applied.

The AER also considers it is reasonable to assume that some customers will be unable to respond to TOU due to their own personal circumstances. Particular examples raised in submissions include low income customers, the disadvantaged and businesses.[163] ACIL Tasman also noted:

> In the short run, consumers are only able to respond to pricing changes with their existing capital stock. In the case of business customers, this means that plant changes are not possible even if, for example, it would be profitable to switch from one fuel to another, this cannot be done. For domestic customers the capital stock in question is generally household appliances such as space heaters and coolers and other equipment that, when replaced, could reduce energy use.[164]

Therefore, the AER considers the ability for customers to respond to customer signals is limited and is likely to occur over a longer period of time than the forthcoming regulatory control period. The AER also notes customer responses in the form of purchasing energy efficient appliances are already accounted for in NIEIR's other policy adjustments (as discussed in section 5.6.5 above).

Even when price signals are clear and customers are able to respond, the AER notes ACIL Tasman's discussion of 'rebound' effects and relativity.[165] Such factors add to

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161 VECCI, *Submission to the AER*, 19 February 2010, pp. 9–13.
162 ibid., p. 11.
163 CUAC, *Submission to the AER*, 17 February 2010, p. 3; AIG, *Submission to the AER*, 12 February 2010, pp. 2–3; VECCI, *Submission to the AER*, 19 February 2010, p. 13.
164 ACIL Tasman, *Review of electricity sales and customer numbers*, p. 54.
165 ACIL Tasman, *Review of maximum demand forecasts*, p. 42.

the uncertainty of TOU impacts and should be considered by the Victorian DNSPs when developing their forecasts.

Examination of price elasticities and other assumptions used

NIEIR and SP AusNet have both relied on a number of studies to inform the elasticities applied to determine the impact of TOU on demand and energy forecasts. However, the studies relied upon have inherent problems when attempting to apply assumptions to demand forecasts in Victoria. This has been noted in ACIL Tasman's report:

> The 'real world' contains a proportion of people who see little or no net benefit in reducing their energy use. Whenever a trial is conducted using volunteers as subjects, it is unlikely that volunteers will include representative from this group of energy users. In trials which are 'opt out', it is more likely that this group will take that option. Trials are unlikely to reflect the impact of an environmental policy on these people.
>
> Hence trials of this kind tend to exaggerate the incentives applying to subjects, because trial participants are more inclined to try to reduce their energy use regardless of the trial and even more likely to do so when given the assistance that comes with the trial itself.[166]

The AER agrees with ACIL Tasman's view and considers that caution should be taken in adopting elasticities recorded from trials. The AER notes 'survivor bias' is another factor that may exaggerate the results from trials. This bias arises where trial participants opt out of schemes for a number of reasons, such as when they move residencies, observe that they have been made worse off or financial circumstances change.[167]

If the reasons for opting out of the trial (or even moving residencies) have not been examined, then the results may overstate the effects of the trial when applied to a 'real world' situation. The AER notes that SP AusNet has implicitly recognised these factors when selecting a long run elasticity at the bottom of the range of point estimates. That said, ACIL Tasman has raised concerns about the studies relied upon by SP AusNet:

- The price changes in SP AusNet's regulatory proposal are substantial when compared to the studies quoted (which assume a constant price elasticity of demand) and a number studies indicate that the elasticity of demand for electricity is non-linear—this is likely to lead to a larger amount of inaccuracy than if smaller price changes were proposed.

- The Monash University study reviewed nine studies, seven of which examined residential elasticity of demand (four of which found the elasticity to be –0.3 and the remaining three less than this amount. The remaining two estimated elasticities

166 ACIL Tasman, *Review of electricity sales and customer numbers*, p. 43.

167 For example in the Oakville Hydro Electricity trial (quoted by SP AusNet), of the 286 participants involved in the apartment building trial, 60 participants (20 per cent of the sample) were removed due to the residents moving out or for other reasons. Navigant Consulting, *Evaluation of individual metering and time–of–use pricing pilot*, 18 March 2008, Report for Oakville Hydro Electricity Distribution Inc, p. 7.

for industrial or commercial customers, which found to be typically lower than the residential estimates. This is in contrast to SP AusNet's critical peak demand analysis.

- The third study referred to by SP AusNet and relied upon when adjusting its energy forecasts examines results conducted by the Salt River Project from an unpublished thesis, which estimates the price elasticity of summer maximum demand—it was unclear what use should be made of this study.[168]

These qualifications (none of which appear to have been recognised or acknowledged by SP AusNet) reinforce the need for caution to be taken when adopting elasticity estimates when there is a dearth of information relating the use of TOU in 'real world' circumstances. The AER also observes that ACIL Tasman conducted a review of the studies referred to by NIEIR and SP AusNet and found:

- demand for electricity is inelastic in the short run
- there is some evidence to support the rebound effect
- demand by business customers is less elastic than demand by residential customers (which is contrary to SP AusNet's critical peak demand modelling used in its energy at risk calculations)
- CPP tariffs initiate a larger response than TOU tariffs.[169]

The AER also notes NIEIR assumed elasticities which started as relatively inelastic and became more elastic. In contrast, SP AusNet has applied own-price and substitution elasticities informed by a range of elasticity estimates.[170] The AER considers that the weight of evidence from pilot studies, NIEIR's approach and ACIL Tasman's advice suggests that SP AusNet's approach of applying what appears to be a long run own-price elasticity of demand for peak electricity is inappropriate.[171] Consistent with the AER's position in previous decisions, the AER considers it is more appropriate to have price elasticities phasing in over time (for example, NIEIR's price elasticity study examined elasticities over a 15 year period).[172] Therefore, the AER considers the approach taken by SP AusNet is likely to overstate the extent to which customers will respond to TOU for the forthcoming regulatory control period.

The AER considers the general approach taken by SP AusNet to model the impact of TOU on residential and small commercial customers appears to be sound. However, the AER has concerns over the inputs and calculations in the model. In particular, it is unclear to the AER whether SP AusNet:

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168 ACIL Tasman, *Review of electricity sales and customer numbers*, pp. 43–49.

169 ibid., p. 48.

170 SP AusNet, *Regulatory proposal*, pp. 93–94. The AER notes SP AusNet has referred to substitution elasticities (relationship between load shifting and relative prices) as cross–price elasticities (relationship between demand and the price of another good). The AER considers that this is an inadvertent error.

171 ACIL Tasman, *Review of electricity sales and customer numbers*, p. 44.

172 For example see, AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, 28 April 2009, pp. 111–112.

- considered the potential impacts of other policies (for example, CPRS, VEET, MEPs, etc) on the inputs in the model—this creates scope for double counting as customers' electricity consumption is likely to be affected by such policies (dampening their response to price signals)[173]

- was correct in assuming a perfectly inelastic own-price demand (0) for off peak electricity consumption (for example, the AER considers there would some response to a price increase to off peak prices, however, it is uncertain what the response would be)

- correctly calculated the transfer of load between peak, shoulder and off peak periods, as it:

  - appeared to confuse cross-price elasticities and substitution elasticities—which are two different concepts (although this may have been an inadvertent error)

  - estimated the amount of load shifting between periods multiplying the substitution elasticity (cross-price elasticity) by the proposed relative price rather than by the change in relative prices (from current to proposed prices)—this has resulted in the amount of electricity transferred from one period to be overestimated to a magnitude of five to nine times (depending on the customer class).

For the above reasons, and notwithstanding the AER's decision to reject all proposed adjustments relating to TOU, the AER considers that SP AusNet's estimated impacts of TOU are overstated and unreasonable.

The delivery of AMI and the introduction of TOU tariffs

The AER considers there are more fundamental issues arising from the combination of the rollout schedule and the Victorian Government's recent decision in response to AMI and TOU. As Origin Energy pointed out, the rollout is scheduled to be completed only by 2013—even in the most optimistic scenario energy consumption is still likely to be less elastic to price in the short run, as certain drivers of customer energy use cannot be changed immediately.[174] Further, the AER notes the Victorian Government has recently announced a moratorium on the use of TOU.[175] The moratorium coincides with a joint assessment between government, industry and consumer groups to:

- ensure the current best practice consumer protection framework for Victorians continued to apply in conjunction with new tariffs

- consider the need for electricity concessions in light of the costs of the rollout and potential equity impacts of new tariff arrangements

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[173] The AER notes NIEIR has made adjustments to policy impacts to account for overlaps (for example 6 star building standards).

[174] Origin, *Submission to the AER*, 11 February 2010, p. 5.

[175] The AER notes the moratorium is on TOU and not the rollout of AMI. Minister for Energy and Resources, *Moratorium to ensure smooth smart meter roll–out*, Media release, http://www.premier.vic.gov.au/newsroom/9853.html>, Accessed on: 1 April 2010.

- examine options for the introduction of TOU, including a pilot pricing trial to assess impacts

- regularly review the impact of TOU tariffs on Victorian families

- investigate the need for an extensive consumer education campaign to provide clear information about smart meters, the new tariffs and what this means for Victorians.[176]

Many of these elements will contribute to a delay in the implementation of TOU tariffs, and create uncertainty about the extent to which price signals will be fully communicated to customers. Notwithstanding the AER's criticisms about the assumptions and approaches used by NIEIR and the Victorian DNSPs, these factors translate into a high degree of uncertainty about the impact of AMI and TOU on the Victorian DNSPs' forecasts for the forthcoming regulatory control period. The degree of uncertainty is such that the AER considers it unreasonable to assume any impact arising from AMI in the forthcoming regulatory control period.

AER conclusion

The AER considers that the Victorian DNSPs' proposed reductions to their underlying forecasts for AMI and TOU pricing impacts are based on unrealistic expectations. The AER considers that the analysis and assumptions used by NIEIR and the Victorian DNSPs are subject to several flaws which are likely to result in the impact on maximum demand being understated and/or overstating the expected reductions in energy consumption. The uncertainties around such expected impacts are considerably high, and are compounded by recent government announcements regarding the delay and ongoing review of TOU tariffs, including potential phased introductions and compensation for some customers. As stated, the degree of uncertainty is now such that the AER considers it unreasonable to assume any impact arising from AMI in the forthcoming regulatory control period.

5.7 AER conclusion

For the reasons outlined in section 5.6, the AER considers that the spatial demand forecasts proposed by the Victorian DNSPs are not 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.

Given the AER's concerns about the Victorian DNSPs' proposed peak demand, energy consumption and customer number forecasts outlined above, it does not consider they are appropriate to form amounts, values or inputs to the AER's determination under clause 6.12.1(10) of the NER.

The AER’s adjustments to the Victorian DNSPs' summation of non-coincident ZSS forecasts, energy consumption and customer number forecasts over the forthcoming regulatory control period are set out in tables 5.27 to 5.31. These adjustments are also

176 The AER notes the moratorium is on TOU and not the rollout of AMI. Minister for Energy and Resources, *Moratorium to ensure smooth smart meter roll–out*, Media release, http://www.premier.vic.gov.au/newsroom/9853.html>, Accessed on: 1 April 2010.

set out in the draft determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

In place of the Victorian DNSPs' proposed forecasts, this draft decision approves the maximum demand forecasts for selected zone substations in each DNSP's network set out in tables 5.22 to 5.26. The AER has also amended the Victorian DNSPs' demand and energy forecasts to remove assumed policy impacts for standby power, insulation subsidy and TOU, as set out in tables 5.27 to 5.31 below. These amendments have been made based on the forecasts presented in the Victorian DNSPs' regulatory proposals, and are the minimum necessary amendments to enable the forecasts to be approved in accordance with the NER, as required by clause 6.12.3(f) of the NER.

The AER has not pursued adjustments arising from several of NIEIR's input assumptions which have now become outdated since the time the Victorian DNSPs submitted their regulatory proposals. The AER expects that such assumptions will be updated when the Victorian DNSPs submit their forecasts in response to this draft decision. The AER will be examine these in its final decision in October 2010. Specifically, the AER expects the following amendments will be made to the Victorian DNSPs' / NIEIR's forecasts:

- update gross state product forecast inputs to reflect more recent economic conditions
- replace population growth forecast inputs with ABS Series B for Victoria, disaggregated by DNSP according to current proposal assumptions about each DNSP's regional contribution to Victorian population growth
- amend the CPRS policy assumption to delay the commencement of the CPRS by 6 months, to 1 January 2012.

Table 5.27 AER conclusion on growth forecasts—CitiPower

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 465	1 509	1 573	1 603	1 627
Energy consumption (GWh)	6 246	6 430	6 544	6 595	6 678
Customer numbers	316 243	321 189	324 686	328 584	334 914

Table 5.28 AER conclusion on growth forecasts—Powercor

	2011	2012	2013	2014	2015
Sum of coincident zone substations (MW)	2 327	2 437	2 569	2 669	2 747
Energy consumption (GWh)	11 163	11 463	11 764	11 994	12 151
Customer numbers	715 541	727 610	739 714	752 719	766 214

Table 5.29 AER conclusion on growth forecasts—Jemena

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 067	1 096	1 134	1 168	1 184
Energy consumption (GWh)	4 439	4 544	4 647	4 725	4 783
Customer numbers	308 296	313 257	317 334	320 907	325 049

Table 5.30 AER conclusion on growth forecasts—SP AusNet

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 858	1 928	2 032	2 125	2 212
Energy consumption (GWh)	8 187	8 345	8 543	8 796	9 039
Customer numbers	634 191	644 900	654 309	663 159	672 912

Table 5.31 AER conclusion on growth forecasts—United Energy

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	2 266	2 352	2 406	2 509	2 558
Energy consumption (GWh)	8 193	8 444	8 710	8 921	9 072
Customer numbers	630 196	634 300	637 565	641 377	646 461

6 Outsourcing and related party transactions

6.1 Introduction

Each of the Victorian distribution network service providers (DNSPs) significantly engage in outsourcing or transactions with parties which are related to them through common ownership. As a result, much of the Victorian DNSPs' operating and capital expenditure forecasts are based on the charges paid to these related party contractors. In some circumstances these charges reflect the actual direct and indirect costs of the related party whereas in other circumstances these charges are set above the related party’s actual costs.

The AER recognises the significant economies of scale and scope of other efficiencies that a DNSP may gain access to through outsourcing. At the same time, the AER also recognises that through outsourcing to related party contractors, a service provider may attempt to maintain their cost base at an ‘artificially inflated’ level in order to influence their future expenditure allowances, increase their regulatory asset base, and retain the benefit of efficiencies for a prolonged or indefinite period of time rather then sharing the benefit of these efficiencies with consumers.

In this chapter the AER considers the appropriate treatment of outsourcing and related party transactions in the context of the Victorian DNSPs' regulatory proposals and the requirements of the NER. The analysis and outcomes from this chapter are then applied to the standard control expenditure forecast analysis in the operating and capital expenditure chapters, and in the assessment of alternative control services.[1]

6.2 Regulatory requirements

The National Electricity Rules (NER) provide that the AER must accept the forecast of required operating expenditure (opex) of a DNSP that is included in a building block proposal if the AER is satisfied that the total of the forecast opex for the regulatory control period reasonably reflects:

- the efficient costs of achieving the operating expenditure objectives
- the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[2]

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1 References to the NER in this chapter generally refer to the requirements relating to the assessment of opex and capex forecasts associated with standard control services, and consequently the approach set out in this chapter is generally geared towards the assessment of standard control service expenditure forecasts. That said, the AER has essentially applied the same approach to the assessment of the DNSPs' proposed alternative control service prices, in respect of the treatment of outsourcing and related party transactions. The approach to alternative control services is discussed further in section 1.5.9 and chapter 20.

2 National Electricity Rules, cl. 6.5.6 (c).

The same criteria apply in relation to the assessment of capital expenditure (capex) forecasts.[3]

If the AER is not satisfied that the forecast opex or forecast capex meet the above criteria the AER must not accept the forecast. In deciding whether or not to accept the forecast the AER must have regard to a number of factors. These factors include:

- the actual and expected opex or capex of the DNSP during any preceding regulatory control periods
- the extent the forecast of required opex or capex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms.[4]

6.3 Summary of Victorian DNSP proposals

6.3.1 CitiPower and Powercor

CitiPower and Powercor consider that the Essential Services Commission of Victoria's (ESCV's) gas access arrangement review (GAAR) 2008-2012 contains the 'most comprehensive regulatory framework' in Australia to date for examining outsourcing arrangements.[5]

According to CitiPower and Powercor, the ESCV adopted a 'case-by-case' approach to reviewing outsourcing arrangements. The ESCV considered that where it was satisfied that payments made under a contract were lower than the costs that would likely be incurred by a service provider undertaking those activities itself, then it considered those payments were likely to be consistent with the Gas Code (including any explicit or implicit margin in the contract price). CitiPower and Powercor argue that the ESCV's approach could result in a contractor:

- receiving an explicit or implicit margin above its directly incurred costs, for example to reflect economies of scale, scope and other efficiencies not available to the regulated business
- retaining, for a period, any efficiency gains that it achieves without being forced to pass them through to the regulated business and ultimately consumers at a rate determined by the regulator.[6]

CitiPower and Powercor consider that the AER should apply the ESCV's framework in assessing their proposed expenditures forecasts for the purposes of clauses 6.5.6(e)(9) and 6.5.7(e)(9) of the NER. These provisions refer to the opex and capex factor that the AER must have regard to the extent the forecast expenditure 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.

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3 NER, cl. 6.5.7 (c).
4 NER, cl. 6.5.6 (d)–(e), 6.5.7 (d)–(e).
5 CitiPower, *Regulatory proposal 2011 to 2015, 30 November 2009*, p.358; Powercor, *Regulatory proposal 2011 to 2015, 30 November 2009*, p.366.
6 CitiPower, *Regulatory proposal*, pp.358-359; Powercor, *Regulatory proposal*, pp.366–367.

CitiPower and Powercor maintain that their agreements with CHED Services and Powercor Network Services (PNS) have been developed on an arm's length basis and reflect arm's length terms.[7]

CitiPower and Powercor submitted numerous consultants' reports with their regulatory proposals. These comprised:

- a report from KPMG comparing CitiPower's 2008 actual costs against KPMG's estimate of the 'in house, standalone' cost of running CitiPower's network, and a separate report containing the same analysis in respect of Powercor
- reports from KPMG (each focusing on different related party arrangements) comparing the terms of the contracts against governance principles for transactions with related parties set down by the CitiPower and Powercor boards
- reports from Ernst & Young (each focusing on different types of services, for example, corporate services) that were commissioned to establish 'arms length' transfer prices applying methods accepted by the Australian Taxation Office (ATO) with respect to the pricing of domestic and international related party transactions, for services provided by CHED Services or PNS to CitiPower and Powercor.

CitiPower's and Powercor's opex and capex forecasts are based on the value of the contracts with its related parties. In negotiating those contracts, CitiPower and Powercor sought advice from Ernst & Young on transfer price margins for individual groups of services (for example, finance) that would be consistent with the ATO's guidance on arm's length related party transactions. Ernst & Young's recommended margins (which vary depending on the service group) were adopted as the notional margins in CitiPower's and Powercor's contracts with CHED Services and PNS. Accordingly, it would seem that CitiPower and Powercor consider that tax guidance on arm's length related party transactions is an appropriate test to apply in assessing expenditure forecasts in an economic regulatory setting.

6.3.2 Jemena

Jemena has entered into an asset management agreement (AMA) with Jemena Asset Management (JAM), which commenced operation on 1 January 2010. The agreement covers a significant amount of the management, construction and maintenance of Jemena's network. Accordingly, forecasts of contract charges under the AMA forms a significant portion of Jemena's opex and capex forecasts. [text removed—confidential].

In support of the [c-i-c] per cent margin, Jemena submitted along with its regulatory proposal:

- a report from Evans & Peck comparing the margin in the AMA (adjusted to reflect a margin for overheads and profit) against the overall (that is, overheads and profit) margin in similar contracts Evans & Peck has had some involvement with

7 CitiPower, *Regulatory proposal*, p.359; Powercor, *Regulatory proposal*, p. 367.

- a benchmarking report from NERA on average industry earnings before income and tax (EBIT) margins which revises a previous NERA EBIT margin benchmarking report in response to criticisms from Allen Consulting Group (ACG) on that previous report

- a probity report from Pitcher Partners on a draft version of the request for proposal issued by Jemena to JAM in the context of the AMA negotiations

Jemena also submitted a report from PriceWaterhouseCoopers (PWC) which reviews the allocation of overheads and indirect costs from Jemena Ltd and JAM to Jemena via the Jemena group's whole of business cost allocation (WOBCA) methodology.

6.3.3 SP AusNet

SP AusNet's opex and capex forecasts include the estimated charges it expects to incur with its related parties in the SP AusNet group, Jemena group and with SPI Management Services (SPIMS).

In support of its expenditure forecasts, SP AusNet's regulatory proposal included:

- [text removed—confidential]

- [text removed—confidential]

6.3.4 United Energy

United Energy states that it is mindful of the regulatory issues that may arise in relation to outsourcing decisions. According to United Energy, the Essential Services Commission of Victoria (ESCV) has examined in detail two alternative business cases:

- service provision from within the business, where no profit margin is earned in relation to the services provided, and

- outsourced services provision, which may be more flexible, innovative and lower cost, but the service provider expects to earn a profit margin.[8]

United Energy stated that from a purely commercial perspective, the primary objective is to deliver the most efficient outcome in terms of price, service performance and risk. According to United Energy, it is common commercial practice to pay a profit margin to an outsourced service provider, providing that the overall outcome is beneficial. In effect, a commercial decision must compare feasible alternatives, and not hypothetical or impractical ones, at an aggregate level. For example, United Energy argues that it is not possible to mix and match components from alternative options to avoid certain cost items, such as profit margins, restructuring or establishment costs.[9]

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8 United Energy, *Regulatory proposal*, p. 30.
9 United Energy, *Regulatory proposal*, p. 30.

United Energy notes that regulatory concerns can arise where outsourced service providers are related to the licensed service provider. United Energy states that it has therefore embarked on a competitive tender process, supported by a probity plan and audit to ensure that these regulatory concerns are addressed.

United Energy states that:

> Having established a competitive framework for selecting the service provider, UED expects that the commercial and regulatory imperatives will be aligned. In particular, the focus from a commercial and regulatory perspective should be on the delivery of the most efficient services to our customers in terms of price, quality and risk.[10]

United Energy's expenditure forecasts are influenced by the significant changes in its business model that it is currently undertaking.

Some components of its current business model, such as the management services it receives from its ultimate owner (Diversified Utility & Energy Trust, DUET) and financial services it receives from a related party (AMP Capital Investors, AMPCI) will not change and United Energy's forecasts reflect the charges paid under these arrangements. The forecasts associated with its immediate owner (United Energy Distribution Holdings, UEDH) and its partially owned subsidiary Pacific Indian Energy Services (PIES) reflect the increased staff expected to be employed by these entities under United Energy's new business model.

However, the most significant impact on its forecasts is in relation to construction and maintenance costs. United Energy's current agreement with JAM for the provision of these services ends on 31 July 2011 and so only the first six months of United Energy's construction and maintenance costs is predicated on this arrangement. Following that, United Energy's opex and capex forecasts reflect the tendered unit costs under its new business model and unit volumes estimated by United Energy.

In support of its opex and capex forecasts, United Energy submitted along with its regulatory proposal:

- a report from KPMG and Johnson Winter & Slattery on United Energy's forecasting methodology for operating and capital expenditure
- a review of its new business model by AT Kearney
- probity reports from Dench McLean Carlson Corporate Advisory on different stages of its tendering process

6.4 Previous regulatory practice

This section summarises the previous regulatory reviews involving related party transactions and the Victorian DNSPs. Those reviews are the ESCV’s 2006–10 electricity distribution price review (EDPR), and the advanced metering infrastructure

10 United Energy, *Regulatory proposal*, pp. 30–31.

(AMI) determination by the AER which regulates the Victorian DNSPs' metering services.

Also summarised in this section is the AER's review of Jemena Gas Network's (NSW) (JGN's) access arrangement. This is the most recent, and to date, most substantial AER review involving related party transactions.

The AER also acknowledges that a substantial body of work on the treatment of outsourcing and related party transactions emerged during the ESCV's 2008–2012 GAAR. During that review, a number of reports from economic and regulatory consultants were commissioned by both the service providers and the ESCV. Some reports covered the conceptual approach to the treatment of outsourcing (and its application to the Victorian gas distributors) whereas other reports focused on the benchmarking of 'margins' paid to contractors over the direct costs of service provision. The conceptual reports on the treatment of outsourcing were:

- the ESCV commissioned advice from ACG (Jeff Balchin)
- Envestra commissioned advice from NERA (Tom Hird) and later CECG (Tom Hird)
- Multinet commissioned advice from NERA (Greg Houston).

While the GAAR is not summarised in this section, the ESCV's approach and the frameworks developed by the above consultants in the context of the GAAR are extensively referenced throughout this chapter.

In developing the approach to outsourcing and related party transactions set out in this chapter, the AER has had close regard to previous regulatory practice including that of the AER itself, the ESCV and the frameworks developed by several economic and regulatory consultants in the context of past reviews.

6.4.1 ESCV—Electricity distribution price determination 2006–10

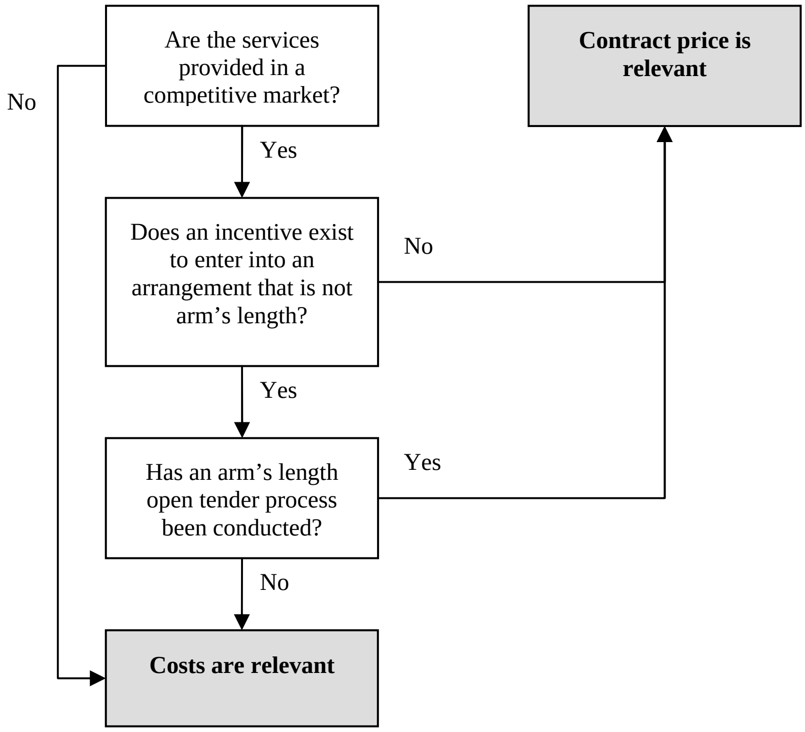
In its 2006–10 EDPR, the ESCV established a framework for the assessment of outsourced contracts. It stated that in determining the costs that are to be used for measuring efficiencies and establishing the future expenditure allowances, the ESCV had to determine whether those costs should be established by reference to:

- the price charged by a third party contractor to the DNSP for providing those services, or
- the costs incurred by that third party contractor in providing those services.

The ESCV established a three stage assessment process to form this judgement.[11] This framework is represented diagrammatically in Figure 6.1.

[11] ESCV, *Electricity Distribution Price Review, Final Decision Volume 1*, October 2006, pp. 171–172.

Figure 6.1 ESCV—Approach to outsourced services in the EDPR 2006–10



Source: ESCV[12]

The ESCV's rationale for the three steps in Figure 6.1 is explained in Table 6.1.

12 ESCV, *Electricity Distribution Price Review, Final Decision Volume 1*, October 2006, p. 172. This flowchart differs slightly from the version that appears in the EDPR. The flowchart as it appears in the EDPR does not appear to fully reflect the ESCV's accompanying written explanation. The AER has been assumed that the written explanation was the intended approach and has amended the flowchart accordingly.

Table 6.1 ESCV—Rationale for approach to outsourced services in the EDPR 2006–10

Stage	ESCV rationale
1. Are the services provided in a competitive market?	Competitive rivalry among suppliers creates strong incentives to produce and price efficiency. If the outsourced services were provided in a competitive market, there can be a high degree of assurance that these services are being provided efficiently, and that the prices charged for these services reflect a competitive market price. Alternatively, if the services are not provided in a competitive market, then there can be no market price for the services and the only relevant consideration is the costs incurred by the third party. Any other approach would involve a subjective valuation of the services (which may be influenced by the incentives of the parties involved).
2. Does an incentive exist to enter into an arrangement that is not arm's length?	If there is an incentive for the parties to enter into arrangements that are other than arm's length, then the means by which the price was established becomes important. However, where no such incentives exist, the contract price can be taken to be a good proxy for the competitive market price.
3. Has an arm's length open tender process been conducted?	Where there is an incentive for the parties to enter into arrangements that are other than arm's length, then if the services have been subject to a competitive tender process the contract price is likely to be a good proxy for the competitive market price. If a competitive tender has not been conducted, then the costs incurred in providing the services are the most practicable point of reference for determining the economic value of the services.

Source: ESCV[13]

The AER notes that in relation to the 'competitive market' criteria, the ESCV's application of its framework was not quite as strict as its stated approach (reflected in Figure 6.1). That is, in practice, where a service was not provided in a competitive market, the ESCV still considered the incentives of the parties and whether a tender process had been conducted, rather than immediately forming the conclusion that the related party's underlying costs are the relevant basis for setting the expenditure allowances and measuring efficiencies.

In relation to when a contract does meet the threshold questions above, the ESCV stated:

> Where the Commission must rely on costs (i.e. where there is no market price either because there is no market for the services or because such a price has not been established through an appropriate process), the building block cost components are to be the appropriate representation of the economic value of the services. These components include a reasonable return on capital consistent with this Determination. This means that where the service

[13] The ESCV also considered that, in principle, it may also be possible to use direct market evidence, if it is established at the outset that sufficiently similar services are provided in a market. However, whether this is possible depends on whether the direct market evidence is sufficiently comparable taking into account the nature of the services, their quantity, the terms of the transactions and the incentives of the parties. ESCV, *EDPR 2006–10*, vol. 1, October 2006, p. 172.

> provider uses regulated assets to provide the services, this return should not be duplicated.[14]

The ESCV's approach made a significant negative impact upon both CitiPower's and United Energy's revenue requirement, however only United Energy appealed.

United Energy appeal

United Energy appealed to the Appeal Panel on the grounds that the ESCV's determination was based wholly or partly on an error in a material respect. Of relevance, United Energy contended that the ESCV made errors of fact in mis-stating the nature of the market in which the operating services agreement (OSA) between United Energy and Alinta Network Services (ANS) was negotiated, and mischaracterised the costs incurred under the OSA as inefficient. The Appeal Panel did not appear to have endorsed the ESCV's focus on market testing, stating:

> The Determination contains a lengthy discussion as to markets and market testing and this has led to some confusion …
>
> Had the comments on markets and market testing contained in the Determination formed the sole or principal basis for the approach taken by the Commission in calculating the Appellant's (United Energy) operating expenses there may be some reason for concluding that this constituted an error in the Determination.

However, the Appeal Panel considered that the critical factor considered by the ESCV was whether an incentive existed for the OSA to have been entered into on a non-arm's length basis. The Appeal Panel endorsed this aspect, stating:

> As the market regulator, the Commission must satisfy itself that the pricing of electricity distribution services is efficient. The Commission is not required to accept that the cost of an outsourcing contract, whether market tested or not, is consistent with efficient pricing. This is particularly relevant in an industry which has monopolistic characteristics …
>
> The Panel considers that it was reasonable for the Commission to enquire into the issue of incentives in relation to non-arm's length dealing and, in this regard, to seek information as to the underlying costs of ANS in order to calculate the 2004 operating expenses of the Appellant.

In dismissing United Energy's appeal that the ESCV made an error of fact, the Appeal Panel found:

> Given that the contractual arrangements between the Appellant and ANS may or may not be consistent with efficient pricing of electricity distribution services, and that information on the costs incurred by ANS in providing services to the Appellant was not made available to the Commission, it was entitled to estimate the costs relevant to the Appellant's electricity distribution activities.

6.4.2 AER—Victorian AMI determination

The order-in-council made under the *Electricity Industry Act 2000 (Victoria)* required the AER to accept the advanced metering infrastructure (AMI) budgets proposed by

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14 ESCV, *EDPR 2006–10*, vol. 1, October 2006, pp. 171–172.

the DNSPs unless it could establish that the expenditure (or part thereof) was for activities ‘outside scope’. Activities within scope were defined as those activities reasonably required:

- for the provision of regulated services, and
- to comply with a metering regulatory obligation or requirement.

Alternatively, the AER could reject a budget if the AER could establish that expenditure (or part thereof) was ‘not prudent’.[15]

The AER rejected the 6 per cent management fees (or ‘margin’) added to the project costs paid by Jemena and United Energy to Alinta Asset Management (AAM, now Jemena Asset Management, JAM) on the grounds that such costs were, for various reasons, not 'within scope', as required by the order-in-council.

The Tribunal found (among other things):

> The second premise is that, to the extent that the management fee is simply a profit margin for the related party, the fee is necessarily for activities outside scope. This premise is incorrect, as a matter of both fact and law. The regulatory principles set out in clause 4 of the AMI Order refer to a building block approach based on, among other things, operating expenditure of the distributor. If a distributor outsources activities, the operating expenditure of the distributor will necessarily incorporate a margin it pays to the party providing the outsourced services. So long as the third party is performing activities within scope, then the profit margin payable to the third party is a cost for those activities within scope. It may be that the profit margin payable is not prudent, but that is a separate matter. In this case, the AER did not establish that the management fee was not prudent. (We are not to be taken as suggesting that in other contexts involving electricity pricing determinations, related party margins are to be treated in the same way.)

In developing the framework in this chapter to assist the AER in assessing outsourcing and related party transactions against the requirements of the NER, the AER has had regard to past regulatory practice, including the Tribunal's findings in the AMI determination appeal. In this respect, the AER notes that:

- the regulatory framework under chapter 6 of the NER against which the AER is assessing the Victorian DNSPs' regulatory proposals is different to the order-in-council against which the AMI charges were assessed
- the Tribunal said its views were not to be taken as suggesting related party margins should be treated in the same way in other contexts
- the issue of the prudency of related party margins was not a focus of the AMI review

15 For example, where a cost was incurred under a contract existing before a certain date, the AER had to accept the cost unless it could establish that the contract was not let in accordance with a competitive tender process, and the costs were either more likely than not to not be incurred, or would involve a substantial departure from reasonable commercial standards.

6.4.3 AER—Jemena Gas Networks (NSW) draft decision

In the AER's draft decision on Jemena Gas Networks (NSW)'s (JGN's) access arrangement review, the AER adopted three principles for the treatment of related party transactions:

- Margins on services provided by external providers are not, in principle, incompatible with the requirements of the National Gas Rules (NGR)
- The AER must be able to verify that the total cost proposed, including any margin applied to a cost base, represents the lowest sustainable cost of providing the service. This may be demonstrated if the costs including the applicable margin for providing services is the result of a competitive tender process.
- Applying a margin where the underlying activity is not undertaken by the party that is charging a margin, is inconsistent with the requirements of the NGR. The AER does not consider that such cost structures can be demonstrated to be efficient.[16]

The AER continues to support the three principles in the JGN draft decision. The approach in this decision follows on from the first principle and sets out the reasons for margins in related party contracts that the AER considers are legitimate and appropriate under the NER and those which are not. It also provides guidance on the second principle in terms of how a business could demonstrate its overall costs are efficient. An extension of this which is discussed in this decision is the appropriate sharing with consumers of efficiency gains achieved through service providers and their related parties operating multiple networks (for example, merger synergies). The AER also continues to support the third principle that 'cascading margins' resulting from entities that do not themselves contribute to the provision of an intermediate service are not an efficient cost structure.

6.5 Issues and AER considerations—Approach to outsourcing and related party transactions

In the previous sections that AER summarised the Victorian DNSPs' proposals and past regulatory practice in respect of outsourcing and related party transactions. In this section the AER:

- sets out its approach to assessing expenditure forecasts under the NER in the context of outsourcing and related party transactions (sections 6.5.1 to 6.5.4), and
- in the context of related party transactions, considers:
  - the appropriate weight to be placed on different types of benchmarking (section 6.5.5)
  - the appropriate treatment of incentive payments and penalties in related party contracts (section 6.5.6)

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16 AER, *Draft decision (public)—Jemena—Access arrangement proposal for the NSW gas networks—1 July 2010–30 June 2015*, February 2010, p.185.

- implications for rolling forward the regulatory asset base (section 6.5.7)
- implications for the measuring efficiencies under the efficiency benefit sharing scheme (section 6.5.8)
- implications for the assessment of alternative control services (section 6.5.9)

6.5.1 Two stage approach

The approach of the ESCV in both the last electricity and gas reviews included a two stage inquiry process. The first stage (referred to in the 2008–12 GAAR by NERA (Greg Houston) as the 'presumption threshold') consisted of determining under what circumstances a contract price could be presumed to be efficient, thereby requiring little or no further examination. The second stage consisted of determining what to do where the contract price could not be presumed efficient.

In the last Victorian EDPR this involved simply adopting the contractor's actual costs as the reference point for measuring efficiencies and setting the future expenditure allowances. In the last Victorian GAAR, it involved estimating what level of expenditure would have been incurred under a 'counterfactual' scenario—being the cost of 'in-house' provision—and then comparing this amount against the contract price.

The AER has also adopted a two stage process for the assessment of outsourcing and related party transactions. In developing this framework, the AER has had regard to the Victorian DNSPs' proposals, the AER's previous approach in the JGN access arrangement, and the past regulatory debate on this issue. Importantly, the AER's approach is consistent with the requirements of the NEL and NER.

The AER's first stage is substantially similar to the 'presumption threshold' from the 2008–12 GAAR. The AER's second stage is also similar that that adopted in the 2008–12 GAAR, however with some important distinctions, particularly in the treatment of economies of scale and scope realised through outsourcing.

In summary, the AER's approach involves the following assessment:

- where a contract passes the presumption threshold—the 'starting point' for setting future expenditure allowances should be the contract price itself, with limited further examination required. This further examination involves checking whether the contract wholly relates to the relevant services (for example,.standard control services) and whether the (efficiently presumed) contract price already compensates for risks or costs provided for elsewhere in the building blocks.
- where a contract fails the presumption threshold—the 'starting point' for setting future expenditure allowances should be the contractor's actual costs itself, with a 'margin' above this level permitted only where the service provider is able to establish the efficiency and prudency of such a margin against legitimate economic reasons for the inclusion of the margin (including its quantum).

6.5.2 Stage 1—Presumption threshold

As noted above, the AER considers a useful exercise is an initial ‘filter stage’. This filter stage is to determine which contracts it is reasonable to presume reflect efficient costs and costs that would be incurred by a prudent operator, and which contracts it is not reasonable to presume reflect these criteria. In undertaking this ‘presumption threshold’ assessment, the AER considers the two relevant questions are:

- Did the service provider have an incentive to agree to non-arm’s length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

In the absence of an incentive to agree to non-arm’s length terms, the AER considers it is reasonable to presume the contract price reflects efficient costs. This presumption is also reasonable where an incentive to agree to non-arm’s length terms exists, however the contract was subject to a competitive open tender process in a competitive market.[17]

Question one: Did the service provider have an incentive to agree to non-arm’s length terms at the time the contract was entered into (or at its most recent re-negotiation)?

Generally, the regulatory regime encourages service providers to seek out efficiencies and minimise costs (particularly in relation to opex). However, there are some instances where a service provider has an incentive to outsource on non-arm’s length terms (that is, at an inefficient or artificially inflated price). The AER considers the main examples of this instance are:

- where the outsourcing contract is with a related party
- where the outsourcing contract is not determined independently from the negotiations of some other contract or arrangement (this may occur with both related and non-related contractors)
- where some other side-payment or benefit is conferred on the service provider in exchange for accepting an artificially inflated price (again, this may occur with both related and non-related contractors)

These instances are considered in turn.

Outsourcing contract is with a related party

Where a service provider outsources activities to a related party (that is, a firm under common ownership to the service provider), then the incentive to minimise the cost of the outsourcing (and only to outsource if it leads to lower costs) is reduced. This occurs given the value of the contract charge has no financial effect on the ultimate owner (as the higher or lower cost to the service provider perfectly corresponds with a higher or lower revenue of the related party) where the ownership of both parties is

17 Although even where contracts are presumed to be efficient, an examination is required as to whether the contract relates wholly to the provision of the relevant service and whether there is any ‘double-counting’ of risks or costs between the contract price and other elements of the building block proposal. These examinations are discussed in section 6.5.3.

identical. Indeed, if there is an expectation that the regulatory regime or the regulator may permit the higher contract price to be factored into regulated charges, then there is an incentive to agree to a higher price than otherwise for the outsourced activities (and possibly also to outsource when it may not reduce cost). If the regulator accepts the non-arm's length or inflated contract price, the service provider continues to recover its full costs while the related party earns inflated profits which can be passed on to its shareholders (being the same shareholders as the service provider).

However, where an investor is a majority shareholder in a service provider but only a minority shareholder in its related party contractor, then the service provider may not have an incentive to agree to non-arm's length terms. This is because the majority shareholder's portion of the profits (or value) that are transferred out of the service provider is greater than its share of the profits that are transferred to the related party. In other words, the transfer of profits from the service provider to the related party results in a net loss for the service provider's majority shareholder unless it is also a majority shareholder in the related party who receives those inflated profits through the transfer pricing.[18] Though as considered in the next section, even in this circumstance the service provider's majority shareholder may permit the service provider to agree to non-arm's length terms if it receives some other side-payment or benefit in exchange for agreeing to the inflated contract price.

The AER's recognition of the importance of considering the incentives of the parties is consistent with past regulatory practice, including that of the ESCV and the views of the appeal panel in the last Victorian EDPR. There appears to be broad agreement among regulators, service providers and economic consultants that looking at whether a perverse incentive to agree to non-arm's length terms existed at the time a contract was negotiated is a relevant consideration in the assessment of outsourced contracts.[19]

Outsourcing contract is not negotiated independently from other negotiations

Where negotiations over an outsourcing contract are not determined independently from the negotiations for some other contract or arrangement, then a service provider may not have an incentive to minimise the cost of the first contract. This is because the price that the service provider is willing to pay under the first contract will depend on the price it pays or receives under the second contract. To generalise the point, the service provider may agree to an artificially inflated or non-arm's length contract price in exchange for some other side-payment or benefit conveyed on it (or on its parent, subsidiary or shareholders). These situations could arise regardless of whether the parties are related by common ownership or not.

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[18] The AER notes that this recognition differs from the ESCV's past practice where United Energy argued that the ESCV did not appreciate the relevance of the difference between controlling and non-controlling shareholders.

[19] However, the AER notes that some of the preferred terminology differs between parties. For example, NERA (Greg Houston) considers the use of the term 'related party' is unhelpful considering the various definitions applied to the term by accountants, lawyers and regulators. In its place, NERA prefers to ask if the parties were acting as a 'single economic entity' stating that this term in commonly used in the US in relation to anti-trust cases. The AER does not disagree with NERA's preferred terminology, and considers the differing terminology used to consider the incentive issue results in substantially similar if not the same outcomes.

A possible circumstance where this may arise in a regulated setting includes where a service provider divests assets or a part of its operations (e.g. its field services staff and associated equipment and vehicles) and enters into an agreement with the party who bought those assets to provide services back to it. The equity value that the service provider would be willing to accept for its divested operations will be dependant on the contract price that it pays the acquiring party for the operating services agreement they enter into.

Question Two: Was a competitive open tender process conducted in a competitive market?

The position that a competitive tender can provide assurance as to the efficiency of a contract price (and sometimes only a competitive tender) is also a common feature of past regulatory practice in relation to the assessment of outsourcing contracts with related parties.

The ESCV explicitly included a competitive tender process criterion in its EDPR and implicitly in the GAAR (generalising it to circumstances surrounding the negotiation of the contract). ACG (Jeff Balchin) considered it important and included it before the incentive criterion, however NERA (Greg Houston) did not include a competitive tender process criterion is its framework (and so presumably did not consider it important). NERA (Tom Hird) included a competitive tender process criterion in its framework but considered the ‘are the services provided in a competitive market?’ test from the EDPR—which was distinct from the ‘has an arm’s length open tender process been conducted?’—should be removed as it unfairly penalises service providers who, through no fault of their own, happen to be forced to pay monopoly rents to input providers.

The AER recognises that there may be limited instances where competitive tendering is impracticable, perhaps due to a shortage of suitable contractors who would be likely to submit an offer or because the cost of the tendering process outweighs the price discovery benefits of this process. In the absence of an incentive on the service provider to agree to non-arm’s length terms, the AER considers it is reasonable to assume that a service provider’s decision whether or not to conduct a competitive open tender will likely be the result of its assessment of the benefits and costs of such a process. Accordingly, the AER considers that it is reasonable to presume a contract reflects efficient costs where a service provider does not have an incentive to accept an artificially inflated or non-arm’s length contract price, even where the contract has not been procured via a competitive tender. In such a circumstance, there the AER has not identified any economic reasons to suggest that the service provider would not be seeking to achieve the best value it can from the negotiation with the third party contractor, in accordance with the positive cost-minimising incentives in the regulatory regime. Nonetheless, where a tender had been undertaken, this would provide the AER with an added level of assurance that the contract is priced efficiently.

In contrast, where an incentive on the service provider to accept non-arm’s length terms exists, the means by which the contract price was determined becomes important. In the presence of such an incentive, the AER considers it should not presume the contract reflects efficient costs or the costs incurred by a prudent operator unless that contract has been subjected to a competitive open tender in a competitive market.

In this regard, the AER agrees with the view of Ofwat also consider that competitive tendering is the only means of testing that provides an objective view as to whether a contract price is efficient. For example, Ofwat has stated:

> … market-testing by these means (published list prices, third party evaluation and benchmarking) did not demonstrate arm's length trading because a large element of subjectivity was involved … these methods of market-testing tended to involve a judgement of a fair market price and/or interference in the market. Ofwat was not satisfied that this form of market-testing produced a fair market price.
>
> The most robust means of determining a fair market price is to invite independent contractors to tender a price for given supplies, works or services – i.e. competitive letting of a contract. Competitive letting is the only means of market-testing which objectively tests and preserves the competitive market. All other methods tend to compare a predetermined price with the market, as a means of justifying the original price. In these circumstances the Appointee has to make a judgement as to what a fair market price should be. Competitive letting avoids this problem as it inherently discovers the market price without interference in or judgement of the market.[20]

Additionally, the AER considers that for contract to pass the 'presumption theshold' the tender process should be conducted in a competitive market. In the absence of this criteria, a service provider may attempt to 'bundle' together a large and disparate group of services in such a way that it would be unlikely to receive many tender proposals—except from its related party or parties—and yet claim the contract had been 'market-tested'.[21]

To assess whether the contract has been subjected to a competitive open tender process in a competitive market would likely involve the assessment of:

- the services provided under the contract (in particular, whether they were 'bundled' in such a way that they could not be said to have been provided in a single market)
- the tender process followed at the time the contract was negotiated (including whether the fees and timeframes imposed on tender applicants were reasonable, and in particular, whether there was any discriminatory treatment towards certain applicants), and

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20 Regulatory accounting guideline 5.04 – Guideline for transfer pricing in the Water Industry (March 2005), p. 11.

21 The AER's addition of the '…in a competitive market' criteria is similar to that adopted by the ESCV in the EDPR 2006. However, the ESCV adopted the question, 'Are the services provided in a competitive market?' as its first decision box (with a 'yes' result leading to the second decision box and a 'no' leading to the conclusion that the 'underlying costs are relevant' for setting the expenditure allowances). The AER's approach effectively removes this question as the ESCV's first decision box and combines it with the AER's second question (the ESCV's third) regarding open tender processes.

- the evaluation of competing tenders undertaken by the service provider (in particular, whether the best value tender application was accepted)

6.5.3 Stage 2A—Assessment where contract passes the presumption threshold

Where a contract 'passes' the presumption threshold specified above, the AER considers it is reasonable to presume the contract price (including any associated margin above direct costs) reflects efficient costs and the costs that would be incurred by a prudent operator in the circumstances of the relevant services provider. This is to be the case regardless of whether the contract is with a related or non-related party.

Where a contract passes the presumption threshold, the AER considers it appropriate to use the contract price as the 'starting point' for setting the future expenditure allowances, however the contract price itself should not be used without the further assessment of two issues. Those are:

- an examination of whether the contract wholly relates to the provision of the relevant service (e.g. standard control services), and
- an examination of whether there is any 'double-counting' of risks or costs between the (efficient) contract price and other elements of the building block proposal.

An examination of whether the contract relates wholly to the provision of the relevant service is a necessary and uncontroversial step to ensure forecasts are set on an appropriate basis and has been applied in previous regulatory approaches.

Where a contract relates to additional services, NERA (Greg Houston) considered this sufficient reason to require a comparison of the contract price with a separately derived estimate of the cost of service provision. However, the AER considers a more practical approach is simply to allocate a portion of the contract price to those other services, with that allocation based on a causation approach, or if a causation approach can not be derived, a well accepted cost allocation approach. For electricity network service providers, this may involve following its approved cost allocation methodology (CAM).

The other examination is to ensure there is no 'double-counting' of certain risks or costs between the (efficient) contract price and other elements of the building block proposal.

Reasons put forward to justify the inclusion of margins in contracts above direct costs include that the margin:

- reflects the transfer of risk (eg. systematic or asymmetric) to the contractor, or
- reflects an allowance for working capital

The AER acknowledges that an efficiently priced contract may include a margin to compensate for these issues. However, even with an efficiently priced contract it does not automatically follow that the contract price in addition to the other elements of a service provider's particular building block proposal result in an overall revenue requirement that reflects efficient costs. This is because of the possibility of a 'double-counting' of certain risks or costs between the contract price and other elements of the building block proposal.

Where it is found that such a double-counting exists, a downwards adjustment would need to be made to either the contract price or the other building block element (depending on which is more practical).

This further assessment of 'double-counting' even where a contract is presumed efficient has to some degree been noted in previous regulatory approaches. For example, ACG (Jeff Balchin) has previously provided the following example in relation to outsourcing and the cost of capital:

> …outsourcing may permit the asset owner to receive other benefits and hence be entered into even if outsourcing is a higher cost option than in-house provision of the relevant function. For example, certain types of outsourcing may reduce the asset owner's cost of capital. While the higher cost from outsourcing would flow into reference tariffs (that is, if the contract price is merely passed through) it is likely that the other benefits would be ignored (if the benefit relates to the cost of capital, then this would be the case, as the cost of capital used for regulatory purposes reflects the circumstances of a notional firm). Thus, paradoxically, while such an arrangement may generate benefits greater than their cost (and potentially be efficient), reference tariffs could rise.[22]

The AER notes, however, that there may be a somewhat different treatment of operating efficiencies from financing efficiencies under the regulatory regime. Through the combination of a price path which in locked in for five years and the efficiency benefit sharing scheme, operating efficiencies are retained by the service provider for an additional five years after the year the efficiency is realised. At the end of this time, the benefit of the operating efficiency is passed on to consumers through lower regulated prices.

In contrast, financing efficiencies are generally retained indefinitely by the service provider and not shared with consumers. For example, due to the benchmark basis on which the cost of debt is set, if a service provider can lower its borrowing costs below the regulatory benchmark then it keeps this benefit. As the same external benchmark will typically be used to set the cost of debt at the following reset, the service provider would continue to retain this benefit without the need to become any more efficient (ie. without the need to lock-in more favourable terms than in the past). Additionally, if a service provider is able to lower its payable company tax through financial restructuring, the benefit from this will typically be ignored by the regulatory regime (resulting in the service provider retaining this financial efficiency indefinitely as well).

Accordingly, it might be reasonable for a service provider to retain operating efficiencies for a time before passing this through to consumers, while retaining financing efficiencies indefinitely (or at least, this is the typical treatment of the respective efficiencies under the regulatory regime). However, the Balchin example

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22 ACG, *GAAR—Outsourcing by regulated businesses—Statement of Jeffery John Balchin*, 22 August 2007, p. 12.

above, noted a circumstance where consumers ended up paying more because of a financial efficiency realised by the service provider. This outcome would seem perverse. The AER considers it may be reasonable for service providers to retain financial efficiencies indefinitely, but at the very least, customers should not have to pay more because of them.

Table 6.2 summarises the possible instances of 'double-counting'.

Table 6.2 AER draft decision—Instances of possible double counting of risks or costs between an (efficient) contract price and other elements of the building block proposal

Instances of possible 'double-counting'	AER response
Has there been a transfer of risk to the contractor without a commensurate reduction in risk compensation in other elements of the building block proposal?	**Asymmetric risk** Asymmetric risk may be fully or partially transferred to a contractor (e.g. under a fixed price contract) yet the service provider may seek a separate self insurance allowance and / or contingency allowance in its proposal resulting in a 'double-counting' of these risks. Depending on what is more practical in the instance, the AER would need to either adjust the contract price downwards or adjust the self insurance allowance / contingency allowance proportionately with the transfer of risk. **Systematic risk** Systematic risk may be partially transferred to the contractor. Given the benchmark basis on which the WACC is set, adjusting the WACC downwards may be impractical (though the NER does allow different WACC parameters for different 'classes' of service provider). Accordingly, the AER may attempt to adjust downwards the contract price (though the AER acknowledges that this may also involve practical difficulties).
Do the services provided under the contract include cost categories that the service provider is also seeking an allowance for elsewhere in its proposal?	**Specific cost categories** For example, a contract may provide for the provision of insurance or debt raising costs, while the service provider also seeks these costs through an additional and separate allowance in its regulatory proposal. Depending on what is more practical in the instance, the AER would need to either adjust the contract price downwards or exclude the separate allowance sought to the extent of the overlap. **Working capital** A contract may provide for a working capital allowance (either directly or indirectly through the margin). However, the cash flow timing assumptions in the PTRM implicitly and fully compensate for working capital. Accordingly, working capital should not also be compensated for through the opex and capex allowances (i.e. through a contract price).

Source: AER analysis

6.5.4 Stage 2B—Assessment where contract fails the presumption threshold

Where the presumption threshold is met, it is reasonable for the AER to presume that the contract price (including any explicit or implicit profit margin) reflects efficient costs that would be incurred by a prudent operator.

However, where a contract does not meet the presumption threshold, the AER cannot presume the contract price reflects efficient costs and so these contracts should be reviewed with greater scrutiny. In these circumstances, the AER considers a logical approach is to adopt the contractor's actual costs—which in most circumstances will be the actual (direct and indirect) costs of a related party—as the 'starting point' and then examine whether there are legitimate reasons to justify a margin above these costs.

NERA (Tom Hird) argues that the existence of a 'margin' above a contractor's direct costs reflects:

- the allowance required to meet the contractor's common costs
- the required return on and return of physical and intangible assets employed by the contractor in the provision of the service
- efficiencies on the part of the contractor over the life of the contract (for example, where the contract allows some part of these to be retained by the contractor)
- the contractor's ability to provide the service at a lower cost than the purchaser could obtain elsewhere (for example, a return to the 'know how' of the contractor)
- the allowance required to self-insure against the asymmetric risks faced by the contractor.[23]

Some of the factors that NERA (Tom Hird) have raised are, on the surface, reasonable justifications for the existence of a margin above the direct costs of the contractor. However, many of these also raise the issue of the possible 'double-counting' of certain risks or costs. In addition, the appropriate treatment under the NER of economies of scale or scale or other efficiencies (such as 'know-how') realised by a related party contractor has significant implications for the appropriate level of margin in the expenditure forecasts.

The AER considers each of the stated justifications above for a margin above a contractor's direct costs in the following sections. Ultimately, the AER considers that whether or not a margin is justified, and the magnitude of that margin where justified, requires a case-by-case examination of the specific contract in the context of the issues discussed in this section. This applies to both contracts with related parties and to contracts with non-related parties where the contract does not meet the presumption threshold. Though, the discussion in this section focuses on the appropriate treatment of margins in the context of related party transactions, as it is these transactions that

23 NERA, *Outsourcing by regulated businesses—Envestra*, 28 March 2007, p. vi.

would mostly commonly be expected to not pass the presumption threshold set out in section 6.5.2.

Other considerations that may be beneficial to consider are:

- a comparison of the contract price with the cost of the service provider pre-outsourcing (particularly where the decision to outsource was made recently)

- the circumstances surrounding the entering into of the contract or arrangement between the services provider and contractor.

Firstly though, the AER considers the appropriate treatment under the NER of economies of scale or scale or other efficiencies (such as ‘know-how’) realised by a related party contractor.

Should expenditure forecasts be assessed against those of a hypothetical ‘fully in-sourced, standalone’ network?

While each of the Victorian DNSPs are separate legal entities, they are also all part of a broader group of companies or corporate group. For example, CitiPower and Powercor are part of the CKI group (which also includes ETSA Utilities), SP AusNet and Jemena are part of both a broader group of ‘SP AusNet’ networks and ‘Jemena’ networks, while ultimately, also all being part of the Singapore Power group. And United Energy is part of a group of DUET-majority owned networks, which includes MultiNet.

Through being part of these groups, each of the Victorian DNSPs have access to significant economies of scale, scope and other efficiencies that would not be available to a ‘standalone’ network. Accordingly, whether or not they should be treated as though they were standalone networks for the purposes of assessing expenditure forecasts under the NER is an important question.

Undoubtedly, these groups will have realised economies of scale and scope and achieved other efficiencies (such as greater ‘know-how) that wouldn’t be available to a hypothetical single ‘standalone’ network. Generally speaking, specialist related parties within these groups provide a particular type of service (for example, management) to all entities within the group. Sometimes these services are on-charged to the DNSP ‘at cost’ (particularly within the SP AusNet group), however these services are mostly on-charged to the DNSP on a ‘cost plus profit margin’ basis (for example, in relation to CitiPower's and Powercor's main related party contractors).

If the relevant expenditure assessment test is the costs of a hypothetical ‘standalone’ network, then this would justify a profit margin added by related parties when charging the service provider than reflects the full extent to the scale economies available to the related party through operating multiple networks. Importantly, if the costs of a ‘standalone’ network are the appropriate standard, then a margin to reflect these scale economies could be justified indefinitely. If this were the case then these economies of scale, scope and other efficiencies available to the group within which the DNSP belongs would be retained indefinitely within that group (that is, by the DNSP's shareholders) and not shared with consumers.

However, the AER notes that one the opex and capex criteria under the NER is the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives. It appears reasonable to conclude that the 'circumstances' of the DNSP includes its ownership structure, and in particular whether or not it is part of a large group of networks giving it access to economies of scale, scope and other efficiencies that wouldn't be available to a hypothetical 'standalone' network.

Were a service provider to actually be a 'standalone' network and not connected to a corporate group that owned and operated multiple networks, the AER does not consider it should be penalised through setting its expenditure allowances below its costs (that is, at a level that would be incurred by a multi-network business). However, should that service provider (or the corporate group the service provider is in) acquire other networks, the AER considers those merger synergies should be retained for a period of time by the service provider but eventually passed through to consumers.

Accordingly, a 'standalone' cost standard would only appear appropriate it that reflects the circumstances under which the service provider is found in. However, where a service provider is part of a larger corporate group that owns and operates multiple networks, then these are the circumstances that service provider is found in, and accordingly this fact is important in assessing the costs that would be incurred by a prudent operator in the circumstances of that DNSP.

Following on from this, the AER does not consider that economies of scale or scope or other efficiencies (for example, 'know-how') are a legitimate reason for a related party contractor to charge the service provider above its direct and indirect costs, as this approach would prevent consumers from sharing in these benefits.

This approach is consistent with how the ACCC has treated merger synergies, such as in the last GasNet access arrangement review. However, the AER notes that this is different to the ESCV's approach in the 2008–12 GAAR, where the ESCV considered:

> Broadly speaking, outsourcing arrangements will be consistent with good industry practice and achieve the lowest sustainable cost of delivering Reference Services in situations where the costs incurred in undertaking those activities are less under an outsourcing arrangement than the costs that would be incurred if those activities were undertaken in-house.

CitiPower and Powercor argue that the AER should apply the same framework as the ESCV in assessing their proposed expenditures forecasts under the NER. [24]

Where the terminology 'standalone' network is used in relation to the appropriate expenditure assessment test, it is often meant (though not always) meant to imply a *fully in-sourced* standalone network.

The AER notes that while the ESCV adopted an 'in-house' expenditure test it does not appear as though it meant this to be equivalent to a 'fully in-sourced' network

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24 CitiPower, *Regulatory proposal*, pp.358-359; Powercor, *Regulatory proposal*, pp. 366–367.

expenditure test. This inference is taken from the ESCV's statement that one of the factors it would consider relevant to its assessment, being:

> …whether the contractor is able to provide the outsourced activities at lower cost than the distributor could obtain elsewhere

The AER agrees with the ESCV in this regard and notes that even a standalone network is able to outsource to specialist contractors rather then providing each service in-house. Indeed, it would seem unlikely that the most efficient model of service provision for a standalone network would be to provide each service in-house, and not to procure any services from an external party (for example, not to ever seek legal advice from specialist law firms and rather to always rely on its own internal legal staff)..

Accordingly, the AER does not consider the concept of a 'fully in-sourced' network is appropriate in assessing the expenditure forecasts against the NER opex and capex criteria of efficient costs and costs that would be incurred by a prudent operator in the circumstances of the DNSP.

Reason one: Margin reflects the allowance required to meet the contractor's common costs

To the extent that a margin reflects a related party's reasonable allocation of common costs then that margin is reasonable. However, the AER considers that relying on allowances for corporate overheads based on an unsubstantiated percentage that is added to direct costs (e.g. direct costs plus 6 per cent for corporate overheads) is not sufficient to establish an appropriate forecast. Rather, as with most other operating costs, an allowance for corporate overheads should be based on historical actual costs, adjusted as appropriate to reflect expected changes in real labour price movements and other such factors.

In additionally, the AER must ensure that only a proper allocation of the related party's corporate costs, and corporate costs that should be allocated to the service provider in the first place, are included within an allowance.

In the 2008–12 GAAR, the ESCV considered:

- costs incurred by a parent entity in undertaking corporate functions that would be required of a distribution business meeting the benchmark assumption should be allocated to the service provider's opex. These functions include corporate governance, treasury, investor relations, HR management and statutory reporting

- costs associated with the management of the equity holders' ownership interests (including the parent entity's ownership interest) should not be allocated to the service provider's opex. That is, costs which are directly associated with the management of equity and not operational costs required to in the provision of regulated services are already compensated through the Weighted Average Cost of Capital.

- costs associated with the parent entity's capital raising costs should not be allocated to the service provider's opex as a separate benchmark allowance is provided for these costs.

The AER agrees with the ESCV's position in these regards.

Management fees paid to parent companies included within the related party's actual costs should also be considered closely to ensure that these fees contribute to the provision of distribution services, and the service provider has substantiated these fees are efficient costs that would be incurred by a prudent operator.

Reason two: Margin reflects the required return on and return of assets employed by the contractor in the provision of the service

A common argument put to regulators is that all contracts with third parties, including efficiently priced contracts with related parties, will necessarily include a 'profit margin' above the contractor's direct and common costs. This sentiment is also expressed by the Australian Competition Tribunal in its judgement on the AMI appeal. Though the Tribunal was careful to state its judgement in that matter was not to be seen as a precedent for the treatment of related party margins, generally.

The regulatory regime does not explicitly provide service providers with a 'profit allowance'. But in its place, it provides a 'return on capital' building block allowance which is calculated as the cost of capital multiplied by the regulatory asset base (RAB). This provides a reasonable return to both equity holders and debt holders for their investment in the service provider. In addition, a 'return of capital' building block allowance is provided which compensates, over time, for the original cost of the assets used by the service provider (which is equivalent to the capital investment by equity and debt holders).

The AER considers a central issue in relation to whether a 'profit margin' in an outsourced contract is justified is whether or not the assets used by the contractor to deliver the service—regardless of whether it is a construction or maintenance service—are already included in the service provider's RAB.

For example, the assets used by a contractor to deliver a construction or maintenance service may include depots, vehicles, equipment and other such assets. Where all of these assets are already in the service provider's RAB, and at the same time the service provider's capex or opex forecast is built on a contract that includes a profit margin (where that profit margin is to compensate for the return on / return of capital associated with assets used by the contractor)—then this would clearly be a 'double-counting' of the same assets.

A non-related party contractor would own a certain amount of assets used to deliver construction or maintenance services. It would be highly usual (and perhaps an error) if these assets were already included in the service provider's RAB. Accordingly, it can be expected that an efficiently priced contract with a non-related party would include a profit margin above the direct and common costs of the contractor to compensate for the return on / return of capital associated with these assets.

In contrast, AER's understanding is that it is common for at least some (if not all) assets utilised by related party contractors to already be included in the service provider's RAB. Accordingly, the AER considers a profit margin in a contract with a related party can only be justified to the extent it utilises assets not already in the RAB.

Reason three: Margin reflects historical efficiencies or future efficiencies

Were the Victorian DNSPs to procure the contracts with their related parties through an open tender process in a competitive market, there would be no need to closely examine the margins in these contracts, as the AER could reasonably rely on ‘the market’ pricing these services efficiently. However, the AER’s understanding of the workings of a ‘workably’ competitive market provides an insight into the appropriate treatment of these relative efficiencies.[25] In a workably competitive market, a contractor could not in the long run charge a premium (i.e. a margin) above its full economic costs and earn abnormal profits due to the efficiencies available to the contractor that are not currently available to the service provider or other contractors. This is because in a workably competitive market, it is assumed that over time existing contractors will become more efficient or new efficient contractors will enter the market and bid away these abnormal profits. In other words, in a workably competitive market a contractor could not earn abnormal profits in the long run for efficiencies it has realised in the past, it could only continue to earn abnormal profits if it were able to continually improve its efficiency relative to its competitors.

To the extent the difference between a contract price and related party contractor’s (full economic) costs reflect past efficiencies, the AER does not consider the contract price should be used to project the future expenditure allowances as this would perpetuate the earning of abnormal profits by the related party which in a workably competitive market would be bided away over time (and therefore not retained indefinitely). Instead, the AER considers that expenditure forecasts should not include an upwards adjustment above the related party’s actual costs to reflect these historically realised efficiencies. Importantly, however, in adopting the related party’s costs no downwards adjustments should be made to reflect any future expected but currently unrealised efficiencies of the related party. Also importantly, the AER proposes that at the end of the regulatory control period, the related party contractor’s actual costs (rather the service provider’s costs, i.e. the contract price) should be used when measuring efficiencies under the EBSS. The result of this is to reward for historical efficiencies through EBSS payments. Consequently, historical efficiencies in the contract margins should not be accepted into the expenditure forecasts. Such an approach provides the service provider with a revenue stream to pay its related party an amount greater than its full economic costs, but only in the short run not the long run, consistent with the workings of a workably competitive market.

To summarise, the AER’s approach in relation to opex and the treatment of efficiencies is that:

- the related party contractor’s actual historical costs (both direct and common) should be used as the basis for the opex forecast (where those historical costs will include historical and realised efficiencies but ignore expected but unrealised future efficiencies),[26] and

[25] One of the objectives of the regulatory regime is to reflect the outcomes of a competitive market. This is generally regarded as the outcomes of a ‘workably’ competitive market rather than a ‘perfectly’ competitive market.

[26] At a particular point in time, a contractor’s actual costs will necessarily incorporate the effect of any efficiency gains it has realised in the past but exclude any future efficiency gains it is expected

- the related party contractor's costs should be used to measure efficiencies at the end of the regulatory control period for the purposes of the EBSS, and
- the related party contractor's (now more recent) actual historical costs should be used as the basis for the opex forecast for the following period.[27]

For capex, the AER also considers that a contract margin that reflects historical realised efficiencies should not be used to project the future expenditure allowance (i.e. this margin should be removed first). And also consistently, any expected but currently unrealised efficiencies should be ignored when setting the future capex allowance.

This is consistent with the ACCC's treatment of merger synergies in the last GasNet decision. In that reset, the ACCC's approach was:

- to ignore both one-off merger (transaction or restructuring) costs and expected (though unrealised) cost reductions resulting from merger synergies for the purposes of determining the forecast opex allowance
- to allow the service provider to retain those merger related cost reductions for a period of six years through the above approach to determining the forecast opex allowance and the calculation of the EBSS allowance at the following reset, and
- to factor those merger synergies into the forecast opex allowance for the following regulatory control period after those cost reductions have been realised.

Under this approach, the merged group of which the service provider is part will retain the merger synergies for six years (regardless of when they are realised) and after this time the benefit of these efficiencies will be passed through to consumers. Importantly, under this approach, somewhat artificial corporate distinctions where a division of a service provider (e.g. its field services team) is turned into a separate but wholly owned company, does not affect the regulatory treatment of merger synergies. Consequently, such somewhat artificial distinctions do not affect the incentive power for the service provider to seek out efficiencies, or the timing or efficiency sharing between the service provider (including its related parties) and consumers.

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to realise in the future but is yet to achieve (and which will therefore lead to its actual costs in the future being lower).

27 In contrast, were the AER to: 1. project the future opex allowance based on a contract which was greater than the related party contractor's full economic costs (because it reflects historically realised efficiencies); and 2. that same contract price to measure efficiencies at the end of the regulatory period for the purposes of the EBSS; and 3. use that same contract price (perhaps re-negotiated by this stage but which still includes a margin above the related party's full economic costs) for projecting the opex allowance for the following regulatory period; then the related party would earn abnormal profits into the long run which would not reflect the expected outcome of a workably competitive market.

Reason four: Margin reflects the 'know-how' of the contractor (or the required return on and return of the intangible assets employed by the contractor in the provision of the services)

Another argument put forward as to why a margin above a related party contractor's actual costs should be allowed is due to the 'know-how' available to a related party contractor that would not be available to the service provider. Alternatively, this is argued from the perspective that the related party holds 'intangible' assets for which it should be allowed to recover both return on and return of capital associated with these intangible assets.

For example, there are few capital assets associated with the provision of most alternative control services. However, there is a degree of 'human capital' (or intangible assets) employed in the provision of these services. These human capital costs are operating costs which are expensed and do not earn a return under the building block approach. Some of the Victorian DNSPs have expressed a view that without a profit margin or a return on these intangible assets, there would be no incentive for their related parties, or indeed the DNSPs themselves, to provide the alternative control services.[28]

In the last Victorian GAAR, Envestra and NERA (Tom Hird, commissioned by Envestra) argued this point. The ESCV summarised Envestra's views as follows:

> Envestra submitted that the actual costs of an outsourcing contractor provide an incomplete basis for estimating the costs that would be incurred by a distributor in the in-house undertaking of outsourced activities. In particular, Envestra contended that the outsourcing contractor incurs costs relating to the contractor's know-how that do not form part of the costs of outsourced activities that are directly accounted for (and in Envestra's case, passed through to Envestra) and which are recovered by the contractor through the margin component of payments under an outsourcing arrangement. Envestra submitted that the Commission's assessment of the in-house costs of undertaking outsourced activities is in error because the starting point for the Commission's consideration of in-house costs (the actual costs incurred by the contractor) does not include costs attributable to the intangible know-how assets of businesses processes, institutional knowledge and the like that are necessary to undertake the activities.

The ESCV summarised NERA (Tom Hird)'s views as:

> Dr Hird provides evidence of the value of intangible assets of a business and draws a conclusion that 'the only reason that a contractor can charge a margin on its actual costs is if the contractor has previously invested in the costly development of those intangible assets'. Dr Hird considers that to not consider a margin over and above actual costs of the contractor as an element of costs implies that:
>
> the contractor does not hold valuable intangible business processes and knowledge or
>
> that the distributor could have costlessly acquired those assets or

28 AER, File note—Meeting with CitiPower and Powercor, 18 February 2010.

> that the distributor should have acquired these assets in the past and should be treated as if it holds the assets[29]

In response, the ESCV considered that:

> The [Gas] Code makes no provision for any additional return on, return of, investment in intangible assets (other than through the allowance for the return of capital and return on capital)
>
> It is the case that historical costs of operating the network which contributed to the development of the business know-how could be recovered under the Code as they are incurred. However, these costs would also form part of the contractor's actual costs.
>
> It has consistently said that if there are economies of scope, scale or other efficiencies that are available to the contractor which are not available to the distributor, that will be relevant. It is then an empirical question as to whether that is the case and the extent and value of such economies. A distributor should not overpay for such economies.
>
> There is no reason to presumptively conclude, as Dr Hird appears to do, that the contract margin captures the full value of this know-how which is not otherwise available to the distributor.[30]

Generally speaking, the AER agrees with the ESCV's views, particularly in relation to the ESCV's second point which deserves greater consideration.[31]

As Envestra and NERA (Tom Hird) point out, 'know-how' or intangible assets are not acquired costlessly by a business. Rather they are only acquired through costly acquisition in the past. The AER considers that these acquisition costs might involve specific training costs, or more broadly the costs of experience. For example, in the past a business may have incurred $1 million to perform a particular task. Over time, through experience and trial and error, a business will gain greater 'know-how' in how best to perform that task which leads to a cost reduction (say, from $1 million to $900 000).

Generally speaking, the AER adopts a 'revealed cost' approach to setting future allowances where these allowances (particularly opex) are projected from historical actual expenditure. Importantly, the ESCV adopted opex and capex allowances of the Victorian DNSPs in the current regulatory control period based on the historical opex and capex of the DNSPs and their related parties. Accordingly, to the extent that a service provider currently possesses 'know-how', this know-how has most likely already been funded by customers. This is because the DNSPs' current expenditure allowances were for the most part based on their historical actual costs in the past before it acquired this know-how and so when it was relatively less efficient than it currently is.

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29 ESCV, *Gas access arrangement review 208-2012—Final decision—Public version*, 7 March 2008, pp. 56–57.

30 ESCV, *Gas access arrangement review 208-2012—Final decision—Public version*, 7 March 2008, p. 57.

31 The ESCV's third point related to the its view on the appropriate cost standard being 'in-house' provision. The AER's position in respect to this matter was set out previously..

To the extent the service provider's or related party contractor's know-how has or will lead to future efficiencies (e.g. through lower costs) then the AER considers it should be treated the same way as most other efficiencies. That is, the service provider and its related party should retain the benefit of this efficiency for a time, but after that the benefit should be past on to consumers. In contrast, for customers to pay a margin above a related party's actual costs because of the 'know-how' or intangible assets in the possession of the related party would be to ask customers to fund something that they have already funded in the past. Accordingly, such expenditure could not be considered efficient or the costs of a prudent operator in the circumstances of the DNSP.

Reason five: Margin reflects the allowance required to self-insure against the asymmetric risks faced by the contractor

A margin to compensate for the asymmetric risks of the related party is legitimate, only if the service provider's proposed self insurance allowance has been commensurately adjusted to only include asymmetric risks faced by the service provider (and not those risks that the service provider has transferred to its related party though its contracting arrangements).

6.5.5 Treatment of benchmarking

EBIT margin benchmarking

It is common practice for service providers to provide consultants reports which benchmark the margins it pays to its related parties with margins earned by contractors in the energy and other industries. However, the AER agrees with the ESCV's views on this matter and consider that it is the overall cost of providing the service which must be prudent and efficient, rather than simply the margin earned. In its final decision on the GAAR 2008, the ESCV stated:

> …the mere presence of a margin that is consistent with industry benchmarks does not mean that the overall level of expenditure under the contract is itself consistent with the Code. The Commission outlined that if that were the case, there would be nothing to preclude a distributor simply restructuring its affairs to move its staff over to a related or associated party and entering into a contract at actual cost plus a margin. The result would simply be to inflate the costs that are recoverable from consumers by the level of the margin. The Commission noted that under this scenario, there would be nothing to preclude a series of cascading contracts in which each contractor in turn sub-contracted to another party at actual cost plus a 'margin'.[32]

Whether or not a margin should be allowed, and the magnitude of that margin if allowed, should not simply be a matter of comparing the margin earned by a related party against industry benchmarks. Rather, the AER considers this is a case-by-case issue and includes consideration of the issues raised in the previous section. For example, whether or not a related party's corporate overhead is already included in the reported expenditure and whether it is utilising assets already in the service provider's RAB has an impact on the appropriate margin for that specific contract.

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32 ESCV, *Gas access arrangement review 208-2012—Final decision—Public version*, 7 March 2008, p. 55.

Overall comparative cost benchmarking

Another way service providers attempt to justify the payment of margins and the overall size of the contract in general is through the comparative cost benchmarking of the service provider's overall capex or opex costs with those of other services providers.

Where the contract provides only a portion of the services required by the service provider to operate its network, the AER considers comparative benchmarking provides little guidance as to the reasonableness of the contract price. This is consistent with the AER's approach in the SP AusNet transmission determination, where the AER stated:

> SP AusNet claims overall benchmarks, rather than management cost specific benchmarks, are easier to construct. Whilst the international study referred to by SP AusNet may suggest that SP AusNet's overall operations are efficient, this assertion says nothing about the efficiency and prudence of SP AusNet's management fees, which is the issue in point.[33]

Alternatively, where the contract essentially outsources the operation of the entire network, then comparative cost benchmarking may be more valid. However, given the difficulties in comparing different service providers (e.g. due to differences in network characteristics or capitalisation policies), while the AER has had regard to overall comparative cost benchmarking the AER has not previously placed significant weight on this type of benchmarking.

Benchmarking against ATO guidance on 'arms length' related party transactions

According to Ernst & Young, the arm's length methodologies that are acceptable to the ATO can be divided into two groups:

- traditional transaction methods, being:
  - comparable uncontrolled price method
  - resale price method, and
  - cost plus method
- profit methods, including:
  - profit split method, and
  - transactional net margin method[34]

Given the different objectives of the economic regulatory regime and the tax regime, the AER considers that it should not be assumed that practices which are appropriate in a tax context are always appropriate in an economic regulatory context.

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33 AER, *Final decision—SP AusNet transmission determination 2008-09 to 2013-14*, January 2008, p. 133.

34 Ernst & Young, *CitiPower Pty and Powercor Australia Limited—Analysis of transfer prices for corporate services*, 20 November 2006, p. 5.

For example, the AER notes that the ATO considers where 'special expertise' is being used by the related party contractor, one would normally expect a substantial mark-up in unrelated party transactions. Accordingly, a high margin in these related party transactions is acceptable. However, the AER considers that this is similar to the 'know-how' argument that been put forward in an economic regulatory context to justify margin in related party contracts.

As set out in section 6.5.4, the AER considers that given the cost-based nature of the regulatory regime, consumers have already funded that know-how and so should now receive a share of the benefit when that know-how leads to efficiencies. Accepting a margin that fully reflects the value of that know-how would mean that consumers do not share in the benefit of the know-how, despite previously having funded its acquisition.

6.5.6 Treatment of incentive payments / penalties in related party contracts

The AER considers that incentive payments built into the contract (e.g. for meeting or exceeding set KPIs) should be excluded from the forecast opex allowance. Consequently they should also be excluded from the actual opex for the purposes of the efficiency calculation in the EBSS. This approach ensures that the efficiencies achieved by the related party are rewarded as if the DNSP achieved those efficiencies itself, with the division of that reward between the DNSP and related party a matter for those parties to settle on.

This approach is consistent with that taken by the ESCV in the 2008–12 GAAR. In its final decision, the ESCV stated:

> The Commission did not consider that it was appropriate to include these payments in the forward looking cost benchmarks. The reason for this is that the Commission is required to consider the forward looking costs of providing the services, whereas an historical sharing of efficiency savings does not actually reflect a future cost of providing the service. Rather, it is a payment between the owner and the operator / manager to reflect superior performance in the past. It must be recognised that this does not mean that the distributor does not receive any allowance for the efficiency saving; they do, but they receive it through the efficiency carryover mechanism. It should also be recognised that this treatment in no way limits the ability of the distributor to share future efficiency savings with the operator / manager.[35]

6.5.7 Implications for the regulatory asset base roll-forward

The AER's assessment of the roll-forward of the Victorian DNSPs' regulatory asset bases to the start of the forthcoming regulatory control period is set out in chapter 9.

During the current regulatory period, each of the Victorian DNSPs' capital expenditure includes margins paid to related party contractors. The AER notes that such amounts were excluded from the Victorian DNSPs' capex allowances by the ESCV for the current regulatory control period, on the basis that these arrangements have the potential to allow for a greater than intended proportion of the benefits of any

[35] ESCV, *Gas access arrangement review 208-2012—Final decision—Public version*, 7 March 2008, p. 57.

efficiency gains to be retained within the corporate group. This characterisation of margins was reflected in amendments to the ESCV's Guideline 3, where it required the Victorian DNSPs to report expenditures net of margins to related parties as they were regarded as not reflecting the costs of providing regulated services.[36]

In making this draft decision the AER has carefully examined the nature of related party margins with respect to the recognition of 'all capital expenditure incurred' under clause S6.2.1(e)(1) of the NER. In particular, the AER has considered the extent to which the margins paid would be characterised as inefficient expenditure or whether they were so excessive as to have no relationship to the services provided by the related party or the DNSP (and therefore not capital expenditure). The AER notes that margins and management fees paid by United Energy and Jemena to a related service provider, Jemena Asset Management, were explored by the Australian Competition Tribunal in its recent ruling on the appeal of the AER's October 2009 AMI Determination.[37] The AER notes that the Tribunal stated that opex of the distributor will necessarily incorporate a margin it pays to the party providing outsourced services.

The presumption in this clause that the AER will automatically recognise all amounts in the DNSPs' RAB roll-forward calculations highlights a potentially serious issue with the capex incentive framework under chapter 6. This issue was raised with respect to capex generally in submissions by the CALC, TEC and EUCV as discussed above.

The apparent requirement for the AER to automatically accept all amounts characterised as capex under clause S6.2.1(e)(1) creates an incentive for DNSPs to enter into related party contracts and seek outcomes contrary to the efficiency objectives of the regulatory framework. For example, a DNSP may present contract charges as actual capital expenditure, yet actual costs of service delivery incurred by the related party may be lower due to efficiency gains or because the service provider receives an inflated contract charge. In this situation, where contract charges are rolled into the RAB, these efficiency gains are retained by the ultimate owner(s) of both entities and there is no incentive for gains to be passed back to consumers.

In the case of opex allowances, incentive carryover mechanisms and the setting of allowances based on underlying costs (not simply contracted rates) ensure that efficiency gains are retained by the DNSP for an appropriate amount of time then passed to end users. However, in the case of capital expenditures, while regulators are able to set allowances that are reflective of efficient costs on an ex ante basis, there are no checks on an ex post basis to ensure the DNSPs are being rewarded or penalised for bona fide efficiency gains or losses. While there is a clear policy intention to not undertake ex post efficiency assessments of capital expenditure, the AER considers that the NER framework needs to address any incentives that a DNSP and its related party may have to capitalise amounts which bear no relationship to actual costs.

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[36] ESCV, *Final decision on Revisions to guideline no. 3 regulatory accounting information requirements*, December 2006,,p. 13.

[37] Application by United Energy Distribution Pty Ltd [2009] ACompT 10.

The AER considers that the capitalisation of related party margins gives rise to more fundamental issues relating to the requirements of clause S6.2.1(e)(1), which would require changes to the NER (including to the equivalent provisions in chapter 6A).

In conclusion, for the purposes of this decision the AER has not sought to make adjustments to the DNSPs' roll-forward calculations with respect to related party margins.

6.5.8 Implications for the efficiency benefit sharing scheme

An important principle behind the efficiency benefit sharing scheme (EBSS) is that the forecast opex allowance and actual opex incurred must be calculated on a like-for-like basis. To do otherwise would distort the calculation of the incremental efficiency gain (or loss), which at worst may reward the service provider for efficiencies not actually achieved, and at best would distort the sharing of efficiencies between the service provider and consumers intended in the scheme.

Following this consistency principle, where the forecast opex is based on the service provider's actual opex (i.e. the contract price) then the 'actual' opex used in the EBSS calculation at the end of the regulatory control period should also be based on the contract price.

Conversely, where the contract price fails the tests outlined in this paper and the AER bases the service provider's forecast opex allowance on the related party's actual opex, then for consistency, the related party's actual opex and not the service provider's actual opex (i.e. not the contract price) should be used in the EBSS calculation at the end of the regulatory control period. This approach ensures that the service provider is rewarded for the efficiencies achieved by the related party in the same way it would be rewarded if it had achieved those efficiencies itself (and most importantly, customers' share of efficiencies is the same as if the service provider had achieved those efficiencies rather than the related party). The sharing of those efficiencies between the service provider and related party is then a matter for those parties to decide and which the AER would not and should not be involved in. This approach is consistent with that followed by the ESCV.

6.5.9 Implications for the assessment of alternative control services

The AER has essentially applied the same framework developed above to its assessment of alternative control services prices proposed by the Victorian DNSPs.

Part of this framework is that historical efficiencies of related party contractors (for example, from economies of scale or scope) should be retained by the DNSPs and their related parties for a period of time, and then passed through to consumers.

In the framework developed in this chapter, the AER proposes to reward DNSPs and their related parties for historical opex efficiencies through the EBSS allowances, and accordingly no 'margin' in the opex forecasts is required to achieve this outcome. However, in recognition that no EBSS is being applied to alternative control services, the AER has allowed a margin in its alternative control services assessment to reward for a period of time for assumed efficiencies realised in the current regulatory control period. However, this margin would not be continued in the period after the forthcoming regulatory control period unless a DNSP is able to demonstrate that it or its related party has achieved further efficiencies in the forthcoming regulatory control period.

6.6 Issues and AER considerations—Assessment of individual arrangements

In this section, the AER summarises its overall assessment of the outsourcing and related party transactions of each Victorian DNSP. Attachment H contains the AER's detailed assessment of each individual major outsourcing and related party transaction.

6.6.1 CitiPower and Powercor

Under separate corporate services agreements (CSAs) and network services agreements (NSAs), CHED Services and Powercor Network Services (PNS) provide most of the management, construction and maintenance services required to operate CitiPower's and Powercor's networks. Asset management functions are retained in-house, but provided across both networks through a joint Citipower and Powercor management team.

CitiPower, Powercor, CHED Services and PNS are all owned by CHEDA Holdings, which is ultimately owned by the CKI / HEH group and Spark Infrastructure.[38]

Given the common ownership of CitiPower and Powercor with CHED Services and PNS, the DNSPs did not have an incentive to enter into arms length arrangements with these related party contractors. Further, CitiPower and Powercor acknowledge that they did not procure these services on a competitive basis or conduct a tendering process.[39] Accordingly, the AER cannot presume that the contract prices of these agreements reflect efficient costs or costs of a prudent operator in the circumstances of CitiPower and Powercor.

CitiPower and Powercor commissioned Ernst & Young to establish ‘arms length’ margins for the services provided under the CSAs and NSAs, using methods they say are acceptable to the ATO for related party transfer pricing. Ernst & Young advised different margins for different types of services ranging from 3.76 per cent for human resources, training and development services to 18.93 per cent for information technology services. The margins from Ernst & Young’s report were adopted as the notional margins in the current agreements. Though given the mostly fixed price nature of the contracts, the outturn margins earned by CHED Services and PNS in any given year may be more or less than these notional margins, depending on their actual costs.

The AER’s critique of related party transfer pricing methods used for tax purposes being applied to economic regulation is set out in section 6.5.5. Accordingly, the AER does not consider that the Ernst & Young reports demonstrate the efficiency or prudency of the margins in these agreements.

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38 CitiPower, *Regulatory proposal*, pp.344-345; Powercor, *Regulatory proposal*, pp. 350–351.

39 CitiPower, *Regulatory proposal*, p.355; Powercor, *Regulatory proposal*, pp. 362–363.

CHED Services’s and PNS's corporate costs have already been factored into CitiPower’s and Powercor’s base opex and capex forecasts—accordingly an additional margin to compensate for a share of their overheads is not appropriate as it would over-recover these costs. Additionally, the AER is not aware of any assets owned and utilised by these related party contractors in providing services to CitiPower or Powercor which are not already contained within the DNSPs’ regulatory asset bases. The existence of such assets would justify a margin being paid, but does not appear to apply here. Accordingly, following the AER’s approach set out in section 6.5.4, a case for a margin above CHED Services’ and PNS's actual costs has not been established.

The AER also notes that prior to these services being provided by CHED Services and PNS, these services were provided by Powercor to both itself and CitiPower. Powercor has moved from a business model where it provided services to itself ‘at cost’ to one where it now pays a related party ‘cost plus margin’ for these same or similar services. The AER is not satisfied that the move to a business model where it now pays a profit margin to a related party (a cost it did not previously incur when providing the same services to itself) reflects the actions of a prudent operator in Powercor’s circumstances.

Further, it appears that most if not all staff utilised by CHED Services and PNS are in fact still directly employed by CitiPower or Powercor. KPMG describes the agreements as follows:

> The Agreements are structured so that Powercor and CitiPower back office employees are effectively “seconded” to CHED and Powercor NS to undertake their daily activities. CHED and Powercor NS then pay Powercor and CitiPower for the use of these resources through a service fee.[40]

CitiPower and Powercor offer the services of their employees to CHED Services and PNS ‘at cost’, but when these related party contractors utilise these same employees to provide services back to CitiPower and Powercor, the DNSPs’ pay ‘cost plus margin’. It would appear that the profit margin CitiPower and Powercor pays to CHED Services and PNS could be avoided by CitiPower and Powercor using its own employees to provide these services to themselves rather than entering into the arrangements they have with their related parties. The AER considers it difficult to see how a prudent operator would second its staff to another business, only to effectively pay their own employees’ salaries plus a profit margin to that business.

Given these considerations, the AER is not satisfied that the profit margins paid to CHED Services or PNS reflect efficient costs or the costs of a prudent operator in the circumstances of CitiPower and Powercor. In the AER’s opinion, it is unlikely that such arrangements would be entered into by parties acting on an arms length basis.

These agreements and CitiPower's and Powercor's other related party transactions are considered further in section H.2 of appendix H.

40 PMG, *Powercor Australia Limited—Consideration of the arms length nature of shared service arrangements*, December 2007, p. 2.

6.6.2 Jemena

Jemena receives most of the management, construction and maintenance services required to operator its network from Jemena Asset Management. Since 1 January 2010, these services have been provided under an asset management agreement (AMA), which replaced a previous letter agreement between the parties. Additionally, Jemena Ltd provides management and administrative staff to Jemena, through there is no formal agreement between the parties. [41]

Under the AMA, JAM provides some services to Jemena itself but also further outsources a number of activities (either directly or indirectly) to other related parties within the Jemena and SP AusNet groups.

Jemena, Jemena Asset Management (JAM) and Jemena Ltd are owned by SPI (Australia) Assets, whose holdings are referred to as the 'Jemena group' in this decision.

Given the common ownership between the parties, Jemena had an incentive to enter into arrangements with JAM and Jemena Ltd that were not arm's length. In addition, Jemena acknowledges that the AMA and its arrangement with Jemena Ltd were not procured on a genuinely competitive basis.[42] Accordingly, the AER considers that it cannot presume that the costs incurred by Jemena under these arrangements reflect efficient costs or costs of a prudent operator in the circumstances of Jemena.

Jemena argues that it 'employed the same internal controls for the AMA negotiations that Jemena would apply to external competitive tenders', with these including structured commercial negotiations with probity controls and documented audit trails.[43]

The AER acknowledges these positive aspects of the process taken by Jemena during the AMA negotiation process. However, the AER does not consider these are sufficient to 'presume' the contract terms reflect arms length terms. Given the incentive for Jemena to agree to non-arms length terms with JAM, the AER considers that only the discipline of a competitive tendering process in a competitive market is sufficient to provide the AER with the assurance that the contract reflects arms length terms without further scrutiny.

A share of Jemena Ltd's and JAM's corporate costs have already been factored into the base opex and capex forecasts—accordingly an additional margin to compensate for a share of Jemena Ltd's or JAM's overheads is not appropriate as it would over-recover these costs.

Additionally, the AER is not aware of any assets owned and utilised by Jemena Ltd or JAM in providing services to Jemena which are not already contained within Jemena's regulatory asset base. The existence of such assets would justify a margin being paid, but does not appear to apply here. Accordingly, following the AER's

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41 Jemena, *Regulatory proposal—Appendix 17.1*, pp. 7,22.
42 Jemena, *Regulatory proposal—Appendix 17.1*, pp. 5–7.
43 Jemena, *Regulatory proposal—Appendix 17.1*, p. 20.

approach set out in section 6.5.4, a case for a margin above Jemena Ltd's and JAM’s actual costs has not been established.

[text removed—confidential]

Jemena states that the services provided directly to it from Jemena Ltd are provided on a cost recovery basis only, with no profit margin to Jemena Ltd added. Accordingly, no related party margin issue arise in relation to this arrangement requiring closer scrutiny. However, the AER has not accepted all of the corporate costs allocated to Jemena from these parties. This issue is considered in sections 6.7.1 and 6.7.3.

Jemena's outsourcing and related party transactions are considered further in section H.3 of attachment H.

6.6.3 SP AusNet

SP AusNet receives management services from SPI Management Services (SPIMS) and IT services from Enterprise Business Services (Australia)(EB Services), a subsidiary of SP AusNet.

SPIMS and SP AusNet are both owned by Singapore Power International. Given the common ownership between the parties, SP AusNet did not have an incentive to enter into an arms length arrangement with SPIMS or EB Services. SP AusNet also acknowledges that that the services were not procured via a competitive tender. Accordingly, the AER cannot presume that the costs incurred by SP AusNet under these arrangements reflect efficient costs or costs of a prudent operator in the circumstances of SP AusNet.

SP AusNet states that the charges it pays to SPIMS and EB Services are based on actual costs with no margin added. Accordingly, no related party margin issues arise in relation to these arrangements. However, the AER has some concerns with the allocation of SPIMS's costs to SP AusNet and the inclusion of a management fee paid to Singapore Power within SPIMS's costs. These issues are considered further in sections 6.7.1 and 6.7.2.

The Jemena group also provides capital works to SP AusNet under a preferred service provider agreement. Given the common ownership between SP AusNet and the relevant entities in the Jemena group (SPIAA, JAM and JAM (6)), SP AusNet did not have an incentive to enter into an arm’s length arrangement with these entities. SP AusNet also acknowledges that there was no tendering process in relation to the procurement of these services.[44] Accordingly, the AER cannot presume that the costs incurred by SP AusNet under the agreement reflect efficient costs or costs of a prudent operator in the circumstances of SP AusNet.

The corporate costs of SPIAA, JAM and JAM (6) allocated to SP AusNet have already been factored into the base opex and capex forecasts—accordingly an additional margin to compensate for a share of the Jemena group’s overheads is not appropriate as it would over-recover these costs. Additionally, the AER is not aware

44 SP AusNet, *Regulatory proposal—Appendix (related party arrangements)*, p. 33.

of any assets owned and utilised by these Jemena group entities in providing services to SP AusNet which are not already contained within SP AusNet's regulatory asset base. The existence of such assets would justify a margin being paid to these Jemena entities, but does not appear to apply here. Accordingly, following the AER's approach set out in section 6.5.4, a case for a margin above the Jemena group's actual costs has not been established.

The AER notes that this agreement with the Jemena group results in related party profit margins being contained within SP AusNet's opex and capex forecasts. SP AusNet itself has explicitly removed the opex profit margin from the calculation of its efficient base year opex, and it states that the removal of this related party profit margin from its base year opex clearly demonstrates its opex forecast meets the prudency requirement in the NER.[45] In contrast, SP AusNet has not removed the same profit margin from its capex forecast. The AER notes that the same prudency requirements in the NER apply to the opex and capex forecasts.

In explaining why this profit margin has not been removed from the capex forecast, SP AusNet states:

> SP AusNet is also of the opinion that the AER's definition if the related party does not have an "incurred cost" for each line of its charge then this should be treated as a profit margin is flawed. All companies whether regulated or unregulated would incur depreciation and cost of capital costs which would not always be revealed just by looking at the make-up of the charges and the statutory accounts. In SP AusNet's opinion related parties should be allowed a return of and return on capital invested just as non related parties include an allowance for these costs in determining their profit margin.[46]

The AER agrees with SP AusNet in that it also considers that the owners of a related party should have a reasonable opportunity to earn a return on and return of the capital the owners inject into the business. However, the AER's contention is that if these assets used by the related party to provide services to the DNSP are already contained within the DNSP's RAB, then the owners of the related party (who are the same owners as the DNSP) will already be receiving a return of and return on these assets. Unlike SP AusNet, the AER does not assume that assets used by the related party but not in the DNSP's RAB, exist in all circumstances. Rather, the AER considers that it is up to the DNSP to demonstrate that there are assets utilised by its related party not in its RAB, and consequently assets where the owners of the related party are not receiving a return on and return of these assets.

Tenix Alliance provides operations and maintenance, asset replacement, and capital works to SP AusNet, in relation to its electricity distribution central region.

There is no common ownership between SP AusNet and Tenix Alliance that would incentivise SP AusNet to enter into a non-arm's length agreement with Tenix Alliance. Further, the AER is not aware of any side-payments or other transactions between the parties that would lead SP AusNet to accept a contract from Tenix Alliance on non-arm's length terms. That said, in section H.4.5, the AER notes a possible limitation on the competitiveness of SP AusNet's process in relation to its

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45 SP AusNet, *Regulatory proposal*, pp. 206–207.

46 SP AusNet, *RIN templates—Related party margins—22 March 2010*, 23 March 2010, p. 4.

agreement for the electricity distribution central region. Notwithstanding this, the AER considers it is reasonably for it to presume that the contract price under the agreement reasonably reflects efficient costs and the costs of a prudent service provider in the circumstances of SP AusNet.

Accordingly, the AER has not made any adjustments to the expenditure forecasts in respect of the margin in the Tenix Alliance agreement.

SP AusNet's outsourcing and related party transactions are considered further in section H.4 of attachment H.

6.6.4 United Energy

United Energy's business model involves it outsourcing management, corporate and financial services to United Energy Distribution Holdings (UEDH), United Energy's immediate parent. UEDH provides some of these services itself, and further outsources other services to specialist providers which are related parties to United Energy, These further outsourcing arrangements are:

- executive management services provided by Pacific Indian Energy Services (PIES) pursuant to a management services agreement (MSA)
- treasury and financial services provided by AMP Capital Investors (AMPCI) pursuant to a financial services agreement (FSA), and
- management and investment services provided by DUET[47]

As United Energy is owned by UEDH, United Energy had an incentive to enter into a non-arm's length arrangement with UEDH. Further, given the common ownership between UEDH and PIES, AMPCI and DUET, UEDH had an incentive to enter into non-arm's length arrangements with these related parties when it further outsourced the services outlined above. Additionally, the AER understands that neither the arrangement between United Energy and UEDH, nor the arrangements between UEDH and PIES, AMPCI or DUET were procured via a competitive open tendering process in a competitive market. Accordingly, the AER cannot presume that these arrangements reflect efficient costs or costs that would be incurred by a prudent operator in the circumstances of United Energy.

United Energy states that there is no profit margin added by UEDH in the services it provides to United Energy, nor is there any (further) profit margin in the services UEDH procures from related parties and on-provides to United Energy.

It is clear from United Energy's proposal that there is no profit margin charged by PIES to UEDH. Accordingly no related party margin issues arise in relation to the services provided by PIES. However, the AER has not accepted the management and financial fees paid to DUET or AMPCI. These arrangements are considered further in section 6.7.1.

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[47] Specifically, the management and investment services are provided by AMPCI Macquarie Infrastructure Management No.1 and AMPCI Macquarie Infrastructure Management No.2, as responsible entities for DUET. United Energy, *Regulatory proposal--Appendix J1*.

JAM currently is the exclusive provider of network planning, construction, management, operation, maintenance and engineering as well as other services to United Energy, under an operating services agreement (OSA) between the parties and UEDH.[48]

While there is some common ownership between United Energy and JAM, there may not be an incentive for United Energy to enter into an arrangement with JAM on non-arm's length terms. This is because United Energy's majority shareholder (DUET) does not have an ownership stake in JAM.

However, as outlined by the AER in section 6.5.2, where the negotiations over an operating services agreement do not occur independently of some other transaction, this lessens the assurance that the terms of the contract reflect arm's length terms because the terms that one party is willing to accept for the operating agreement will be dependent on the terms of the other transaction. The negotiations over the OSA occurred as part of a larger transaction involving an ownership re-organisation of United Energy known as the 'Shearwater transaction'.[49] Further, United Energy acknowledges that JAM was appointed as the operator under the OSA without any tender process.[50] Accordingly, under the presumption threshold set out in section 6.5.2, the AER cannot presume that the OSA fees reflect efficient costs or the costs that would be incurred by a prudent operator in the circumstances of United Energy.

The corporate costs of JAM have already been factored into the base opex and capex forecasts—accordingly a margin to compensate for a share of JAM's overheads is not appropriate as it would over-recover these costs.[51] Additionally, the AER is not aware of any assets owned and utilised by JAM in providing services to United Energy which are not already contained within United Energy's regulatory asset base. The existence of such assets would justify a margin being paid to JAM, but does not appear to apply here. Accordingly, following the AER’s approach set out in section 6.5.4, a case for a margin above JAM's actual costs has not been established.

The first renewal period under agreement with JAM expires on 30 June 2011, and United Energy has advised that it does not intend to extend the agreement. United Energy has undertaken a tender process to replace some of the services currently

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48 Specifically, the contract is with Jemena Asset Management (6) (JAM (6)). JAM (6) was previously known as Alinta Asset Management, and before that Alinta Network Services.

49 The 'Shearwater transaction' was a large series of transactions which involved: Power Partnership (a company owned by Aquila and AMP) acquiring the remaining 42.95 per cent of shares in United Energy Limited that it did not previously own; Alinta and entities managed by AMP Henderson buying Aquila's 59.3 per cent interest in Power Partnership; Aquila selling its interests in its other Australian assets, namely an indirect holding in Alinta and its 48.2 per cent economic interest in the Multinet Partnership; AMP Henderson creating a new, wholesale diversified energy fund being DUET with the intention that DUET would be managed by AMP Henderson and would comprise two wholesale unit trusts whose securities would be stapled; and reorganising assets as between Alinta, United Energy and DUET. United Energy, *Scheme booklet for the scheme of arrangement between United Energy Ltd and the holders of UEL shares in relation to the proposal with Power Partnership Pty Lid*, 30 May 2003.

50 United Energy, *Regulatory proposal--Appendix J1*, pp. 7–8

51 The AER notes that JAM's 2008 costs have been adopted for the purposes of this draft decision, however these will be updated for JAM's 2009 costs in the final decision.

being provided by JAM, with other services currently provided by JAM to be provided in-house by United Energy (and UEDH and PIES).

United Energy argues that its forecast has been market-tested and so can be relied upon as being efficient. However, the AER notes that it is essentially only the tendered unit costs which have been market-tested with the other three components of its opex forecast estimated by United Energy. The AER has reviewed the tendering process and is reasonably satisfied with this process. However, the AER has concerns with each of the remaining three components of United Energy's bottom up build of its costs.

The AER has reviewed United Energy's tendering process and considers that the process adopted by United Energy appears reasonably competitive and involved a large number of applicants. That said, the AER has some concerns with the competitiveness of this process in relation to two clauses in the current JAM contract which:

- provide JAM with a 'right to match' the terms of any future contract that replaces its existing contract; and
- require any contractor that replaces JAM (or some other entity) to offer to purchase at least a certain proportion of United Energy (from Jemena) at a price determined by an independent valuer.

The AER considers that these clauses in the current contract may have dissuaded some applicants from participating in the tendering process or from rigorously competing for it under the knowledge that even if they were the preferred bidder JAM might exercise its right and end up with the contract.

Notwithstanding the potential concerns the AER has over the competitiveness of the tendering process, the fact that four consortia sought to be involved in the final stage of the tendering process indicates that the process was likely to have been reasonably competitive. Accordingly, the AER considers that the new agreement with the preferred tender applicant passes the presumption threshold and the AER can presume that the contract charges under this contract reasonably reflect the efficient costs that would be incurred by a prudent operator in the circumstances of United Energy.

United Energy's outsourcing and related party transactions are considered further in section H.5 of attachment H.

6.7 Issues and AER considerations—Assessment of related party contractors' corporate costs

As set out in section 6.5.2, the AER has adopted a 'presumption threshold' to assist it in separating outsourcing arrangements the AER can reasonably presume reflect efficient costs that would be incurred by a prudent operator, from those the AER cannot reasonably so presume, and so must scrutinise closer against the requirements of the NER.

The most common case where an outsourcing arrangement often does not 'pass' the presumption threshold is when that arrangement is with a related party contractor, given in these circumstances the service provider may not have an incentive to enter into arm's length arrangements.

In section 6.5.4, the AER stated that where a outsourcing arrangement does not pass the presumption threshold, it would assess the 'margin' above the contractor's direct costs in the arrangement against legitimate economic justifications for a margin. One of those reasons is the recovery of a share of the contractor's corporate overheads or other indirect costs.

Notwithstanding the legitimacy of this reason, the AER also recognises that there may be circumstances where a related party contractor's overheads allocated to the DNSP would not reflect efficient costs incurred by a prudent operator, and therefore not meet the requirements of the NER. For example, these corporate overheads include:

- management fees paid to the parent of the related party (and DNSP) that are not an efficient cost that would be incurred by a prudent operator, or the management fees may not sufficiently contribute to the provision of distribution services
- an over-allocation of the related party's corporate costs to the DNSP
- corporate cost categories that might ‘double-count’ costs recovered elsewhere in the regulatory regime (e.g. debt raising costs), or
- other corporate cost categories that do not sufficiently contribute to the provision of distribution services or are not an efficient cost that would be incurred by a prudent operator.

In this section, the AER examines the above issues in the context of the corporate and indirect costs allocated to the Victorian DNSPs by their related parties.

6.7.1 Assessment of management and financial fees paid by related party contractors to parent companies

The AER has identified several instances of management fees paid by related parties to parent companies where the AER is not satisfied that the payment of such fees reasonably reflects efficient costs that would be incurred by a prudent operator. Additionally, the AER is of the view that these fees do not sufficiently contribute to the provision of distribution services. These payments are:

- management fees paid by SPI Management Services (SPIMS) to Singapore Power and to Jemena (these fees are included within SP AusNet’s forecast opex and capex)
- management fees paid by Jemena Ltd (through SPIAA) to Singapore Power (these fees are included within Jemena’s and United Energy’s forecast opex), and
- management fees paid by UEDH to DUET (these fees are included within United Energy's forecast opex).

Management fees paid to Singapore Power (Jemena, SP AusNet, United Energy)

In 2008-09, the management fee paid by SPIMS to Singapore Power was $5.7 million and an additional $74 000 was paid to Jemena ($5.8 million in total). Of this amount, $2.7 million was allocated to SP AusNet's regulated electricity distribution business, split between $1.8 million opex and $0.9 million capex.

In its last transmission determination, the AER rejected in full the portion of this fee SP AusNet allocated to transmission. The ESCV also rejected this fee in full in the last gas access arrangement review. The AER noted that the services provided in exchange for this fee were for vaguely defined services such as ‘accountability’ and ‘due diligence’. The AER considered that SP AusNet had not substantiated that these management costs (essentially a third tier of management in addition to SP AusNet’s board and management company) would be required by a prudent operator in SP AusNet’s circumstances (i.e. SP AusNet has not substantiated the value it receives that would justify the payment of this fee). The AER’s reasons for rejection rested on prudency and efficiency grounds, while the ESCV's reason for rejection was that the costs were not relevant to the provision of reference services.

SP AusNet has not provided any substantive further information in its (distribution) regulatory proposal justifying the payment of this fee against the requirements of the NER. Similarly, SP AusNet has not provided any specific information on the small fee paid to Jemena. Accordingly, consistent with the transmission determination, the AER considers that SP AusNet has not demonstrated these fees are an efficient cost that would be incurred by a prudent operator, especially considering the significant management costs already incurred by SPI Management Services in the absence of this additional cost. That is, SP AusNet has not provided information that demonstrates the value to SP AusNet’s customers of funding this fee to Singapore Power. Further, SP AusNet has not demonstrated that these fees sufficiently contribute to the provision of distribution services.

Accordingly, the AER has removed this fee from SP AusNet's expenditure forecasts. As SP AusNet capitalises a portion of these fees, this adjustment affects both SP AusNet’s opex and capex forecasts.

A management fee for similar services is paid by Jemena Ltd (through SPIAA) to Singapore Power. In 2008, this fee was [c-i-c] million, of which [c-i-c] million was allocated to Jemena and [c-i-c] million was allocated to United Energy. In its regulatory proposal, Jemena described the services provided by Singapore Power as 'management consulting and advisory services'. Upon further inquiry, Jemena stated that Singapore Power provides 'strategic support' to the Jemena group, including:

- strategic group finance advice
- group corporate governance and compliance
- strategic advice regarding management of regulatory matters[52]

[52] Jemena, *JEN response to AER email of 3 February 2010—Question 5*, 18 February 2010, p. 1.

United Energy has not provided any specific information about these services other than the cost.

The AER notes that the fee relates to services provided to the Jemena group by its Singaporean management. While the fee may be of some benefit to the Australian management and the strategic and corporate functions of the Jemena group (although this has not been well established), the AER has concerns about the direct relevance of this management fee to the provision of distribution services.

Based on the information provided, the services provided by Singapore Power in exchange for the management fee are strategic in nature and relate to the corporate strategy and direction of the Jemena group. The AER considers that this fee appears to primarily benefit the Jemena group's shareholders rather than consumers, and is not sufficiently connected to the provision of distribution services.

Further and similar to the scenario with SP AusNet, Jemena and United Energy have not substantiated the efficiency or prudence of these fees. Given the significant management and corporate costs already incurred by Jemena Ltd and JAM, the AER is not satisfied that this additional management cost reflects efficient costs or a cost that would be incurred by a prudent operator.

Management fees paid to DUET (United Energy)

UEDH sources services from AMPCI Macquarie Infrastructure (the responsible entity of DUET). The details provided on this arrangement in United Energy's regulatory proposal are highly limited.

United Energy's regulatory proposal only states that these fees are for ‘management and investment services to UEDH’ and that DUET plays an 'important role' in the management of UED. It states that DUET provides oversight and management of investors' capital and incurs a range of related corporate governance and regulatory compliance costs.[53]

However, United Energy's regulatory proposal:

- does not explain why United Energy choose to outsource this service and why its own management team (including the UEDH and PIES management staff) were not capable of providing these services themselves
- does not explain the process under which the services were procured (for example, whether the services were procured using a competitive tender)
- does not explain how the fee is calculated and how this relates to the underlying costs of DUET
- does not clearly explain the amount of the management fees which are included in its expenditure forecasts, and

[53] United Energy, *Regulatory proposal--Appendix J1*, pp. 2–6.

- does not include a copy of the contract[54]

As noted above, it is not clear from United Energy's proposal the amount of its forecast opex and capex which is attributable to these management fees. United Energy's consolidated budget model contains a line item labelled 'shareholder costs' which feed into its opex forecast. This amount is $6.0 million per annum or $29.8 million over the forthcoming regulatory control period. However, while not clear from United Energy's proposal, this line item appears to be the combination of the management fees paid to DUET and the financial services fees paid to AMPCI (discussed below).

Based on the limited amount of information provided by United Energy, the AER is not satisfied that the management fees paid to DUET reasonably reflect efficient costs that would be incurred by a prudent operator in the circumstances of United Energy. Accordingly, the AER has not included these fees in its estimate of United Energy's opex forecast.

Financial services fees paid to AMP Capital Investors (United Energy)

UEDH also sources treasury and financial services from AMP Capital Investors (AMPCI). The AER has reviewed the contract and considers that there appears to be a substantial overlap between the services provided under this arrangement and the separate debt raising costs allowance sought by United Energy in its regulatory proposal. Given this ‘double-counting’ of costs within United Energy's expenditure forecasts, the AER is not satisfied that the inclusion of these financial services fees in addition to the separate debt raising costs allowance within United Energy's opex forecast reasonably reflects efficient costs that would be incurred by a prudent operator.

Accordingly, the AER has not included the financial services fees paid to AMPCI in its estimate of United Energy's opex forecast. The AER's consideration of the debt raising cost allowance (and equity raising cost allowance, where relevant) proposed by United Energy and the other Victorian DNSPs is set out in appendix P.[55]

AER conclusion—Management fees paid by related party contractors to parent companies

The AER's assessment of the management and financial services fees paid to parent companies of the Victorian DNSPs is summarised in Table 6.3.

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[54] This arrangement was the only transaction between UED or UEDH and a related party where United Energy did not include the contract in its regulatory proposal.

[55] The AER notes that in its estimate of United Energy's base opex it has included the 'FSA—Treasury front office' cost category from United Energy's internal corporate budgeting model. Accordingly, despite the exclusion of the FSA fees paid to AMPCI, the AER's estimate of United Energy's opex already appears to cover the internal administrative costs associated with debt raising that would be expected to be incurred by a prudent operator.

Table 6.3 AER draft decision—Management fees paid by related party contractors to parent companies ($'m, 2010)

	DNSP proposal		AER draft decision	
	Base year amount	**Regulatory period amount(**	**Base year adjustment**	**Regulatory period adjustment**
Jemena (opex)	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
SP AusNet				
- Opex	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
- Capex	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
- Total	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
United Energy (opex)				
- Sing. Power fee	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
- DUET fees	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
- Total	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Total	**7.7**	**38.2**	**-7.7**	**-38.2**

Source: DNSP regulatory proposals; AER analysis

6.7.2 Allocation of related party contractor's corporate costs to the DNSP

The cost allocation methodology (CAM) process involves the allocation of a DNSP’s costs, especially indirect costs, between standard control, alternative control, negotiated, and unregulated services. Essentially, the CAM applies to costs which 'enter' the DNSP.

However, another issue is the allocation of corporate or other indirect costs to the DNSP itself, where corporate services are provided to the DNSP by a related party contractor. This issue arises in relation to each Victorian DNSPs as each is part of a corporate group where a specialist corporate services entity provides management and corporate services to the DNSP.

The main such entities in relation to the Victorian DNSPs are:

- CHED Services in relation to CitiPower and Powercor
- Jemena Ltd and JAM in relation to Jemena
- SPIMS in relation to SP AusNet, and
- UEDH and PIES in relation to United Energy

The AER has identified issues in relation to the allocation of SPIMS's corporate costs to SP AusNet.

Allocation of SPI Management Services' costs to SP AusNet

The AER has identified an issue with the SP AusNet group's allocation of SPIMS costs between its different business segments—regulated electricity distribution, regulated gas distribution, AMI, unregulated distribution, regulated transmission, unregulated transmission, and non-SP AusNet businesses.

SPIMS’s costs are allocated between the segments based on a management survey of ‘effort’. As the survey is completed regularly (currently every three months), the percentage allocations between segments changes annually. From the results of the survey, it appears as through when management exerts more effort on different business segments in the lead-up to its regulated proposal, the result of SP AusNet’s allocation method is that an above-average allocation of management costs feeds into the base year opex used to set the operating forecast for that reset. Furthermore as different base years are used for different resets (and the allocations between business segments change annually), this leads to the situation where accepting the outcome of SP AusNet’s allocation method for the Victorian electricity distribution determination would result in the SP AusNet group recovering more than 100 per cent of SPIMS’s costs.

For example, 22 per cent of SPIMS’s costs fed into the 2006 opex base year used in the last gas access arrangement review by the ESCV. However, only 12 per cent of SPIMS’s costs in 2009 are being allocated to gas distribution, resulting in a greater proportion of SPIMS's costs being allocated to other business segments in 2009, such as electricity distribution. 2009 is the base year proposed by SP AusNet (and accepted by the AER) for the opex base year in this electricity distribution determination.

The opex base year allocations adopted in the last electricity transmission, gas distribution and AMI reviews, compared to the same segment’s 2009 allocations, are outlined in Table 6.4.

Table 6.4 SP AusNet proposal—Allocation of SPI Management Services costs to individual SP AusNet group business segments under its survey of management effort method (per cent)

Business segment	Base year allocation	2009 allocation	Difference
Transmission regulated	35 (2006-07)	26	9 less
Gas distribution regulated	22 (2006)	12	10 less
AMI regulated	5 (2008)[a]	9	4 more
Electricity distribution regulated	31—Opex (2009) 15—Capex (2009) 46—Total (2009)	31—Opex 15—Capex 46—Total	–
Transmission unregulated	2	2	–
Distribution unregulated	4	4	–
Non SP AusNet	1	1	–
Total	**115**	**100**	**–**

(a) The AER has assumed that 5 per cent of SPIMS costs are being recovered through the AMI determination. This percentage equates to SP AusNet's allocation of SPIMS's cost to AMI in 2008, though the AMI budget itself was not set using a 'base year' approach.

Source: SP AusNet.

The AER considers that in future electricity and gas determinations it may be more appropriate to allocate SPIMS's costs to each business segment using an average of the management effort percentage allocations over several years for that business segment. That will result in more stable allocations between years, and consequently an allocation into the base year of each reset that is more representative of a typical year's costs.

However, as the AER and ESCV accepted the management survey allocations in the last transmission and gas resets, to adopt the average approach in this determation would still result in the SP AusNet group recovering more than 100 per cent of SPIMS's costs.

Accordingly, the AER has adopted a 'residual' approach for the early years of the forthcoming electricity distribution regulatory control period, allocating to electricity distribution the SPIMS costs that are not already being recovered through the current transmission, gas or AMI determinations or being allocated in 2009 to unregulated or non-SP AusNet activities.[56] This results in a base year adjustment to reflect 31 per cent of costs being allocated to electricity distribution (whereas SP AusNet's management survey method results in 46 per cent to the base year), split between 21

[56] The AER has assumed that 5 per cent of SPIMS costs are being recovered through the AMI determination. This percentage equates to SP AusNet's allocation of SPIMS's cost to AMI in 2008, though the AMI budget itself was not set using a 'base year' approach.

per cent opex and 10 per cent capex.[57] To give effect to the allocation of SPIMS costs to electricity distribution using a ‘residual approach’ at the start of the regulatory period, and an ‘average approach’ after the current transmission, gas and AMI determinations have finished, the AER has added back a (positive) step change to the opex and capex forecasts towards the end of the forthcoming regulatory control period. This is necessary to transition to the average approach for the allocation of group costs to the SP AusNet.

The combination of the (negative) base adjustment and (positive) step changes is a reduction in SP AusNet’s total opex forecast by $6.3 million and a reduction in the total capex forecast of $3.1 million.

6.7.3 Assessment of corporate strategy costs incurred by related party contractors and allocated to the DNSPs

This section considers the financial strategy, investment analysis and energy investments cost categories which are enterprise support function (ESF) costs (that is, corporate costs) incurred by Jemena Ltd, and allocated to Jemena and United Energy under the Jemena group’s whole of business cost allocation (WOBCA) methodology. These costs are included within Jemena's opex forecast.

The total financial strategy, investment analysis and energy investments costs incurred by Jemena Ltd in 2008 was [c-i-c] million. Of this amount, [c-i-c] million was allocated to Jemena and approximately [c-i-c] was allocated to United Energy under the WOBCA.[58]

The AER sought further information from Jemena on why each of these costs are allocated to the provision of distribution services. Jemena gave the following descriptions of each of the cost categories in response.

On the financial strategy cost category, Jemena states that it needs to ensure it has access to operational and fully supported financial systems in order for it to conduct its operations. It also submits that it requires financial analysis support for the projects that it undertakes. The services provided by the financial strategy unit include:

- the provision of support and integrity for key finance systems focusing on the general ledger
- finance support for key commercial and strategic initiatives of the business.[59]

On the investment analysis cost category, Jemena submits that it must undertake budgeting, forecasting and financial modelling in order for it to conduct its operations. The services provided by the investment analysis unit include:

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57 The relative proportions of the opex and capex split are consistent with SP AusNet's allocations in 2009.

58 Jemena, *Regulatory proposal—Appendix 7.3 'PWC, Independent review: JAM cost of service to JEN—Corporate ESF & overhead cost allocation methodology', 14 October 2009'*, pp.15-16; PWC, *Alinta Asset Management—United Energy OSA—2008 actual costs*, p.18. The WOBCA allocates financial strategy and investment analysis costs to United Energy but not energy investments. Amounts have been converted to real $2010.

59 Jemena, *JEN response to AER email of 3 February 2010—Question 5*, 18 February 2010, pp.1-2.

- group budgeting and forecasting
- ownership of the corporate model and long term forecast
- financial modelling and project support.[60]

Jemena states that budgets and forecasts prepared by the business units are consolidated into a group budget and forecast which is used by the Jemena group executive leadership, the SPIAA board and Singapore Power International to make strategic business decisions including decisions on the capital structure and to update stakeholders. Jemena also submits that the corporate model is used by the business and SPI to support strategic decision making. This includes decisions on the most efficient capital structure for the business and for supporting the carrying value of the group's assets. Further, Jemena states that modelling support is provided for specific projects throughout the business, including development projects and regulatory determinations.

On the energy investments cost category, Jemena submits that its energy investment unit serves to maximise the financial returns from Jemena group's equity investment in wholly-owned or partially owned assets. It submits that this is achieved by:

- protecting and creating incremental value in the asset businesses
- effective management of regulatory matters
- effective asset control
- effective management of government relations.[61]

As noted in connection with the Singapore Power management fee, the AER considers that services of a strategic nature may not be sufficiently connected to the provision of distribution services and are more likely to be connected with owners' interests and benefits. The AER considers that in relation to finance support there seems to be activities directed to strategic initiatives of the business.

While the AER acknowledges that budgeting and forecasting and financial modelling are associated with the provision of distribution services, the AER has concerns that the primary purpose for the investment analysis activities is not for the benefit of users of distribution services delivered on Jemena's network. As outlined above, the purpose of the budgets and forecasts prepared by the business units into consolidated accounts, is to provide information for the executive management to make strategic decisions for investment opportunities, decisions on capital structure and to update the owners of the Jemena group's businesses. The AER notes that Jemena provides no specific examples of modelling support provided for specific projects in relation to its regulatory proposal.

The AER considers that the primary function of the energy investment unit is to increase shareholder return as it 'maximises the financial returns from Jemena

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60 Jemena, *JEN response to AER email of 3 February 2010—Question 5*, 18 February 2010, p. 2.
61 Jemena, *JEN response to AER email of 3 February 2010—Question 5*, 18 February 2010, pp. 2–3.

[group's] equity investment in wholly-owned or partially owned assets'.[62] The AER does not consider that these activities support the provision of distribution services but instead benefit the owners of Jemena. Given the nature of the energy investment activities undertaken, the AER considers that costs related to energy investments do not meet the requirements of the NER.

Overall, the AER considers that Jemena has provided insufficient information on the nature of the financial strategy, investment analysis and energy investments costs to substantiate that these are costs sufficiently connected to the provision of distribution services so as to be recoverable under its standard control opex forecasts. Even if these were sufficiently connected to the provision of distribution services, the AER notes that a question would still remain as to whether they are efficient costs that would be incurred by a prudent operator in Jemena's (and United Energy's) circumstances. Based on the information provided, the AER is not satisfied that this is the case.

Given the above considerations, the AER has not included the financial strategy, investment analysis or energy investments cost categories in Jemena's or United Energy's base opex. Consequently, these costs are not included within the AER's draft decision on Jemena's or United Energy's opex forecasts.

6.8 AER conclusion

Outsourcing to specialist providers of a particular service is a common means by which businesses in the economy are able to gain access to economies of scale and scope and other efficiencies (for example, 'know–how'). Accordingly, service providers should be provided with effective incentives to seek out efficient and prudent outsourcing and related party transactions.

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

The AER has developed a conceptual framework to assist it in assessing the Victorian DNSPs’ operating and capital expenditure forecasts assist against the requirements of the NER. In developing this framework, the AER has had regard to the Victorian DNSPs’ proposals, the AER’s previous approach in the JGN access arrangement draft decision, and the past regulatory debate on this issue.

The first stage of the AER's framework is a 'presumption threshold' designed to be an initial filter to determine which contracts it is reasonable to presume reflect efficient costs and costs that would be incurred by a prudent operator, and which contracts it is not reasonable to presume reflect efficient costs or costs that would be incurred by a

[62] Jemena, *JEN response to AER email of 3 February 2010—Question 5*, 18 February 2010, p. 2.

prudent operator. In undertaking this ‘presumption threshold’ assessment, the AER considers the two relevant considerations are:

- Did the service provider have an incentive to agree to non-arm’s length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

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

Where an arrangement 'passes' the presumption threshold, the AER considers the starting point for setting future expenditure allowances should be the contract price itself, with limited further examination required. This further examination involves checking whether the contract wholly relates to the relevant services (e.g. standard control services) and whether the (efficient) contract price already compensates for risks or costs provided for elsewhere in the building blocks.

Where a contract fails the presumption threshold, the AER considers the starting point for setting future expenditure allowances should be the contractor’s actual costs itself, with a ‘margin’ above this level permitted only where the service provider is able to establish the efficiency and prudency of such a margin against legitimate economic reasons for the inclusion of the margin (and its quantum).

The AER identified some limited concerns with the tendering processes conducted by SP AusNet in its appointment of Tenix Alliance and by United Energy in its appointed of its 'turn key service provider' to replace Jemena Asset Management. However, the AER still considered that these arrangements passed the presumption threshold and so the AER can presume these arrangements reflect efficient costs that would be incurred by a prudent operator. Both these arrangements are with parties who are not related to the service provider.

The related party margins of each of the Victorian DNSPs did not pass the presumption threshold, and so the AER considered whether a margin above the related party's direct costs is appropriate. Two of the reasons the AER considers are legitimate economic reasons for the inclusion of a margin are to:

- compensate for a share of the contractor's corporate and other indirect costs, and
- retain the benefit of historical efficiencies for a period of time.

That said the AER's assessment the related party's corporate costs have already been included in the DNSP’s expenditure forecasts. In addition, the AER is seeking to reward the Victorian DNSP's for the historical efficiencies realised by their related parties through the efficiency carryover mechanism (ECM) allowance. Accordingly, no additional 'margin' in the expenditure forecasts is required to compensate for these reasons.

Additionally, the AER has identified some issues with the corporate costs of the related parties of Jemena, SP AusNet and United Energy and has made adjustments to these costs. These issues include corporate costs not sufficiently connected to the provision of distribution services and management fees paid to parent companies that the AER is not satisfied reasonably reflect efficient costs incurred by a prudent operator.

The other legitimate economic justification for a margin is to compensate for the return on and return of capital invested in assets utilised by the related party contractors, where those assets are not already in the service provider's regulatory asset base (RAB). The AER is not aware of the existence of such assets. However, if particular Victorian DNSPs are able to demonstrate the existence of such assets in their revised proposals then the AER would allow in its final decision a margin to compensate for the return on and return of those assets.

7 Operating and maintenance expenditure

7.1 Introduction

This chapter sets out the AER’s conclusions on forecast operating and maintenance expenditure (opex) allowances for the Victorian DNSPs for the forthcoming regulatory control period. It also:

- provides a general overview of the proposals
- addresses comments made by stakeholders on the proposals
- summarises the AER’s main considerations and responses to stakeholder comments
- discusses the framework the AER has applied in assessing each proposal against the requirements set out at clause 6.5.6 of the National Electricity Rules (NER)
- sets out the AER's reasons why it does not accept the Victorian DNSPs' forecast opex proposals
- sets out the estimate of the total of each Victorian DNSP's required opex for the forthcoming regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

This estimate and the AER’s conclusions are set out in section 7.6 of this chapter.

7.2 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 the building block proposal of each Victorian DNSP on the basis of whether the AER is satisfied the forecast opex proposals reasonably reflect the opex criteria (which in turn refer to the opex objectives), taking into account the opex factors.

The opex objectives, criteria and factors are set out below.

7.2.1 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.

7.2.2 Opex criteria and factors

Clause 6.5.6(c) of the NER provides that the AER must accept the forecast opex included in a building block proposal if it is satisfied that the total of the forecast opex for the regulatory control period reasonably reflects:

> (1) the efficient costs of achieving the opex objectives; and
>
> (2) the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In making this assessment, the AER must have regard to the following opex factors contained in clause 6.5.6(e) of the NER:

> (1) the information included in or accompanying the building block proposal;
>
> (2) submissions received in the course of consulting on the building block proposal;
>
> (3) any analysis undertaken by or for the AER and published before the distribution determination is made in its final form;
>
> (4) benchmark opex that would be incurred by an efficient DNSP over the regulatory control period;
>
> (5) the actual and expected opex of the DNSP during any preceding regulatory control periods;
>
> (6) the relative prices of operating and capital inputs;
>
> (7) the substitution possibilities between opex and capex;
>
> (8) whether the total labour costs included in the capex and opex forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;
>
> (9) the extent to which the forecast of required opex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm’s length terms; and
>
> (10) the extent the DNSP has considered, and made provision for, efficient non-network alternatives.

Clause 6.5.6(d) of the NER states that, if the AER is not satisfied that a DNSP’s forecast opex reasonably reflects the opex criteria, the AER must not accept the forecast opex in a building block proposal. If the AER does not accept the total forecast opex proposed by a DNSP, clause 6.12.1(4)(ii) of the NER requires the AER to include in its draft decision:

> … an estimate of the total of the DNSP’s required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

7.3 Summary of Victorian DNSP regulatory proposals

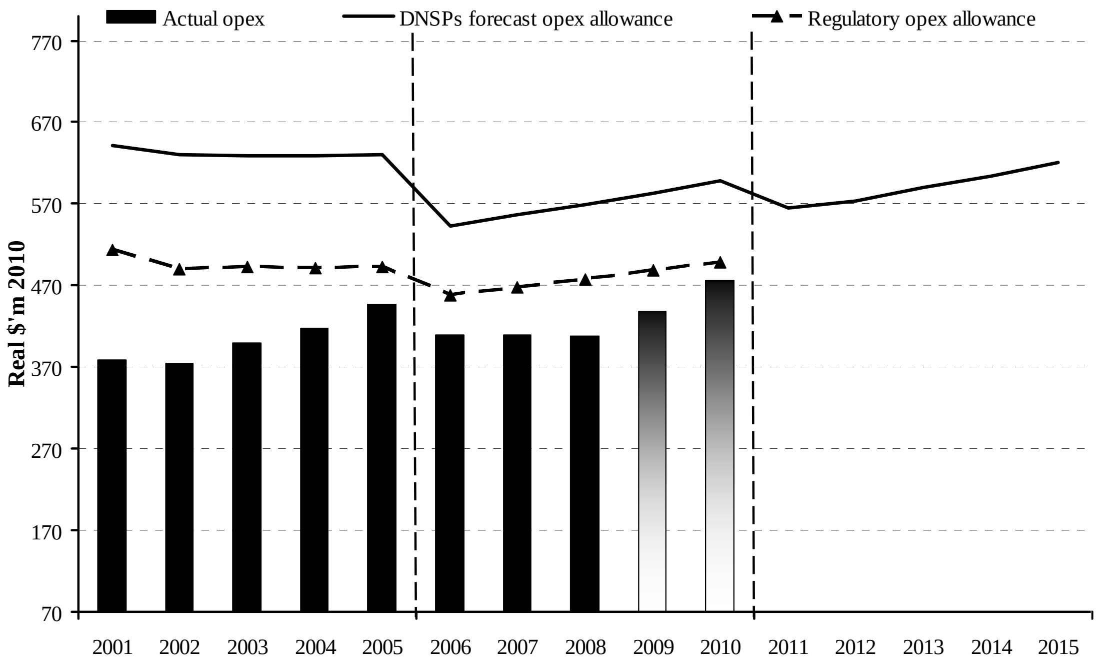
7.3.1 Current period outcomes

This section summarises the Victorian DNSPs' actual opex outcomes compared to the allowances set by the Essential Services Commission of Victoria (ESCV) and the Victorian DNSPs' own regulatory proposals.

The Victorian DNSPs expect to underspend their regulated opex allowances by approximately $248 million ($2010) or 10 per cent of the allowances set by ESCV during the current regulatory control period. In relation to the Victorian DNSP's regulatory proposals for the current regulatory control period, the Victorian DNSPs expect to underspend by $710 million ($2010) or 25 per cent.

Figure 7.1 shows the Victorian DNSPs actual and allowed total opex in the current and previous regulatory control periods, and their proposed forecast opex for the forthcoming regulatory control period.

Figure 7.1 Victorian DNSP current regulatory control period outcomes ($'m 2010)



Source: AER analysis

The Victorian DNSPs' actual opex is represented by the bars in Figure 7.1 above. The Victorian DNSPs current underspend relative to the ESCV regulatory opex allowance is denoted by the difference between the bars and the dashed line. The Victorian DNSPs' underspend relative to their own proposals is denoted by the difference between the bars and the solid line. The 2009 and 2010 bars represent the Victorian DNSPs' estimated opex as audited actuals are not yet available.

The analysis indicates that the Victorian DNSPs' proposed levels of efficient opex exceed audited actual opex by a margin of between 25 per cent and 41 per cent for the current and previous regulatory control periods.

The analysis also confirms that the Victorian DNSPs' actual costs generally sit below the approved efficient regulatory opex allowance. The Victorian DNSPs, during the current and previous regulatory control periods, have demonstrated they continually outperform their opex regulatory benchmarks.

The ongoing incentive for the Victorian DNSP to reduce costs reveals an efficient starting point for the AER's assessment of forecast opex (see section 7.5.1 for a discussion on the AER's approach to assessment).

The analysis above, when repeated for each Victorian DNSP, supports the general conclusion that the Victorian DNSPs outperform the opex regulatory benchmarks, and their own proposed levels of efficient opex sit well in excess of audited actual opex.

In relation to the regulatory opex allowance set by the ESCV for the current regulatory control period:

- CitiPower expects to underspend their regulated opex allowance by approximately $39 million ($2010) or 19 per cent of the allowances set by the ESCV for the current regulatory control period

- Powercor expects to underspend their regulated opex allowance by approximately $55 million ($2010) or 8 per cent of the allowances set by the ESCV for the current regulatory control period

- Jemena expects to underspend their regulated opex allowance by approximately $46 million ($2010) or 15 per cent of the allowances set by the ESCV for the current regulatory control period

- SP AusNet expects to underspend their regulated opex allowance by approximately $77 million ($2010) or 12 per cent of the allowances set by the ESCV for the current regulatory control period

- United Energy expects to underspend their regulated opex allowance by approximately $31 million ($2010) or 6 per cent of the allowances set by the ESCV for the current regulatory control period.

In relation to the Victorian DNSPs' regulatory proposals for the current regulatory control period:

- CitiPower expects to underspend against its regulatory proposal by $162 million ($2010) or 49 per cent

- Powercor expects to underspend against its regulatory proposal by $232 million ($2010) or 26 per cent

- Jemena expects to underspend against its regulatory proposal by $73 million ($2010) or 22 per cent

- SP AusNet expects to underspend against its regulatory proposal by $164 million ($2010) or 22 per cent

- United Energy expects to underspend against its regulatory proposal by $79 million ($2010) or 14 per cent.

7.3.2 Regulatory proposals

The Victorian DNSPs' total forecast opex for the forthcoming regulatory control period (Table 7.1) is $2 953 million ($2010), which represents an increase of $812 million, or 38 per cent above the Victorian DNSPs' expected actual opex in the current regulatory control period of $2 141 million. Table 7.1 to 7.6 set out each Victorian DNSP's forecast opex by cost category for the forthcoming regulatory control period.

Table 7.1 Victorian DNSP proposed opex for the forthcoming regulatory control period ($'m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
Network operating costs	47.6	197.0	59.5	291.2	160.6	755.9
Billing and revenue collection	15.9	27.7	17.2	4.0	10.0	74.8
Customer service	13.3	38.3	18.9	46.5	40.8	157.8
Advertising / marketing	0.3	0.5	5.8	11.3	4.3	22.1
Regulatory costs	9.2	21.0	14.7	6.6	10.5	62.0
Other network operating costs	6.9	17.2	89.2	160.1	227.1	500.5
GSL payments	–	12.1	0.1	19.7	0.3	32.2
Total operating costs	**93.1**	**313.8**	**205.4**	**539.4**	**453.6**	**1 605.4**
Routine maintenance	25.2	213.9	55.2	45.3	36.7	376.3
Condition based maintenance	55.3	182.3	34.4	189.7	53.0	514.8
Emergency maintenance	33.9	122.4	22.1	99.3	29.3	307.0
SCADA and network control	0.9	6.3	2.3	0.8	29.2	39.5
Other maintenance	13.9	29.9	–	–	–	43.9
Total maintenance	**129.2**	**554.9**	**114.1**	**335.1**	**148.2**	**1 281.5**
Debt raising costs[a]	21.6	33.5	–	19.9	–	75.0
Other[a]	–	–	–	–8.7	–	–8.7
Total opex	**244.0**	**902.3**	**319.4**	**885.7**	**601.8**	**2 953.2**

Source: Regulatory Information Notice, 30 November 2009, PTRM, 30 November 2009
(a) For relevant notations see Table 7.2 to Table 7.6

Table 7.2 CitiPower proposed opex for the forthcoming regulatory control period ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Network operating costs	9.5	10.4	11.5	7.9	8.4	47.6
Billing and revenue collection	3.0	3.1	3.2	3.3	3.4	15.9
Customer service	2.9	2.5	2.6	2.6	2.7	13.3
Advertising / marketing	0.0	0.1	0.1	0.1	0.1	0.3
Regulatory costs	1.7	1.8	1.8	1.9	1.9	9.2
Other network operating costs	1.4	1.4	1.5	1.3	1.4	6.9
GSL payments	–	–	–	–	–	–
Total operating costs	**18.4**	**19.1**	**20.6**	**17.1**	**17.9**	**93.1**
Routine maintenance	4.5	4.7	5.0	5.4	5.7	25.2
Condition based maintenance	9.6	10.2	11.0	11.9	12.6	55.3
Emergency maintenance	6.0	6.3	6.7	7.2	7.6	33.9
SCADA and network control	0.2	0.2	0.2	0.2	0.2	0.9
Other maintenance	2.8	2.5	2.7	2.9	3.0	13.9
Total maintenance	**23.0**	**23.9**	**25.6**	**27.5**	**29.1**	**129.2**
Debt raising costs	4.0	4.3	4.4	4.5	4.5	21.6
Other	–	–	–	–	–	–
Total opex	**45.4**	**47.3**	**50.6**	**49.1**	**51.5**	**244.0**

Source: Regulatory Information Notice, 30 November 2009, PTRM 30 November 2009

CitiPower's total forecast opex for the forthcoming regulatory control period is $244 million ($2010), which represents an increase of $73 million, or 43 per cent above CitiPower’s expected actual opex in the current regulatory control period of $171 million.

Table 7.3 Powercor proposed opex for the forthcoming regulatory control period ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Network operating costs	34.6	36.9	39.2	41.8	44.5	197.0
Billing and revenue collection	5.1	5.3	5.5	5.8	6.0	27.7
Customer service	8.0	7.2	7.4	7.7	8.0	38.3
Advertising / marketing	0.1	0.1	0.1	0.1	0.1	0.5
Regulatory costs	4.0	4.1	4.2	4.3	4.4	21.0
Other network operating costs	3.2	3.3	3.4	3.6	3.6	17.2
GSL payments	2.2	2.3	2.4	2.5	2.6	12.1
Total operating costs	**57.3**	**59.2**	**62.3**	**65.8**	**69.2**	**313.8**
Routine maintenance	39.4	41.0	41.9	43.1	48.7	213.9
Condition based maintenance	33.1	34.7	36.4	38.2	40.0	182.3
Emergency maintenance	21.9	23.1	24.4	25.8	27.2	122.4
SCADA and network control	1.2	1.2	1.3	1.3	1.3	6.3
Other maintenance	5.8	5.6	5.9	6.2	6.5	29.9
Total maintenance	**101.4**	**105.6**	**109.7**	**114.5**	**123.7**	**554.9**
Debt raising costs	6.4	6.4	6.7	7.0	7.0	33.5
Other	–	–	–	–	–	–
Total opex	**165.0**	**171.3**	**178.7**	**187.3**	**199.9**	**902.2**

Source: Regulatory Information Notice, 30 November 2009, PTRM, 30 November 2009

Powercor's total forecast opex for the forthcoming regulatory control period is $902 million ($2010), which represents an increase of $251 million, or 38 per cent above Powercor’s expected actual opex in the current regulatory control period of $652 million.

Table 7.4 Jemena proposed opex for the forthcoming regulatory control period ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Network operating costs	11.9	11.4	11.8	12.1	12.4	59.5
Billing and revenue collection	3.4	3.3	3.4	3.5	3.6	17.2
Customer service	3.8	3.6	3.7	3.8	3.9	18.9
Advertising / marketing	1.2	1.1	1.1	1.2	1.2	5.8
Regulatory costs	2.3	2.2	2.2	4.6	3.5	14.7
Other network operating costs	17.7	17.0	17.7	18.2	18.6	89.2
GSL payments	–	–	–	–	–	0.1
Total operating costs	**40.2**	**38.6**	**40.1**	**43.3**	**43.2**	**205.4**
Routine maintenance	10.9	10.9	11.1	11.3	11.1	55.2
Condition based maintenance	6.8	6.8	6.9	7.0	6.9	34.4
Emergency maintenance	4.3	4.4	4.4	4.5	4.4	22.1
SCADA and network control	0.4	0.5	0.5	0.5	0.5	2.3
Other maintenance	–	–	–	–	–	–
Total maintenance	**22.4**	**22.6**	**22.8**	**23.3**	**22.9**	**114.1**
Debt raising costs[a]	–	–	–	–	–	–
Other	–	–	–	–	–	–
Total opex	**62.6**	**61.1**	**62.9**	**66.7**	**66.1**	**319.4**

(a) Debt raising costs already included in Regulatory Information Notice total opex
Source: Regulatory Information Notice, 30 November 2009, PTRM, 30 November 2009

Jemena's total forecast opex for the forthcoming regulatory control period is $319 million ($2010), which represents an increase of $57 million, or 22 per cent above Jemena’s expected actual opex in the current regulatory control period of $263 million.

Table 7.5 SP AusNet proposed opex for the forthcoming regulatory control period ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Network operating costs	52.3	56.5	59.9	60.5	62.1	291.2
Billing and revenue collection	0.8	0.8	0.8	0.8	0.8	4.0
Customer service	9.1	9.1	9.3	9.5	9.6	46.5
Advertising / marketing	2.0	2.2	2.3	2.4	2.4	11.3
Regulatory costs	1.4	1.4	1.3	1.3	1.3	6.6
Other network operating costs	30.2	31.1	31.6	33.9	33.4	160.1
GSL payments	4.0	4.0	3.9	3.9	3.9	19.7
Total operating costs	**99.7**	**105.0**	**109.0**	**112.2**	**113.5**	**539.4**
Routine maintenance	8.9	9.1	9.0	9.1	9.2	45.3
Condition based maintenance	37.1	38.3	37.7	37.9	38.7	189.7
Emergency maintenance	19.1	19.4	19.8	20.2	20.8	99.3
SCADA and network control	0.2	0.2	0.2	0.2	0.2	0.8
Other maintenance	–	–	–	–	–	–
Total maintenance	**65.2**	**66.9**	**66.7**	**67.4**	**68.8**	**335.1**
Debt raising costs	3.5	3.7	4.0	4.3	4.5	19.9
Other[a]	–	–2.2	–2.2	–2.2	–2.2	–8.7
Total opex	**168.4**	**173.4**	**177.5**	**181.7**	**184.7**	**885.7**

(a) Removal of S-factor true up costs included in Regulatory Information Notice total opex

Source: Regulatory Information Notice, 30 November 2009, PTRM, 30 November 2009

SP AusNet's total forecast opex for the forthcoming regulatory control period is $886 million ($2010), which represents an increase of $297 million, or 50 per cent above SP AusNet's expected actual opex in the current regulatory control period of $589 million.

Table 7.6 United Energy proposed opex for the forthcoming regulatory control period ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Network operating costs	32.4	31.7	32.1	32.1	32.2	160.6
Billing and revenue collection	2.6	1.8	1.8	1.9	1.9	10.0
Customer service	8.1	8.2	8.2	8.2	8.2	40.8
Advertising / marketing	1.8	0.6	0.6	0.6	0.6	4.3
Regulatory costs	2.7	1.8	1.8	2.0	2.3	10.5
Other network operating costs	46.2	46.6	45.6	44.8	44.0	227.1
GSL payments	0.1	0.1	0.1	0.1	0.1	0.3
Total operating costs	**93.8**	**90.8**	**90.2**	**89.6**	**89.3**	**453.6**
Routine maintenance	7.2	7.3	7.4	7.4	7.4	36.7
Condition based maintenance	11.0	10.5	10.5	10.5	10.5	53.0
Emergency maintenance	6.0	5.8	5.8	5.8	5.8	29.3
SCADA and network control	5.8	5.9	5.9	5.9	5.9	29.2
Other maintenance	–	–	–	–	–	–
Total maintenance	**29.9**	**29.5**	**29.6**	**29.6**	**29.6**	**148.2**
Debt raising costs[a]	–	–	–	–	–	–
Other	–	–	–	–	–	–
Total opex	**123.8**	**120.2**	**119.7**	**119.2**	**118.9**	**601.8**

(a) Debt raising costs already included in Regulatory Information Notice total opex
Source: Regulatory Information Notice, 30 November 2009, PTRM, 30 November 2009

United Energy's total forecast opex for the forthcoming regulatory control period is $602 million ($2010), which represents an increase of $135 million, or 29 per cent above United Energy’s expected actual opex in the current regulatory control period of $467 million.

7.4 Summary of submissions

A number of stakeholders commented that the AER is required to rigorously assess the Victorian DNSPs' opex proposals.[1]

The Energy Users Coalition of Victoria (EUCV) commented that the AER's approach to assessing the Victorian DNSPs' proposals should maintain continuity with the approach of the ESCV, to rely on actual opex plus identified step changes:

> … the ESCoV used the actual opex used and allowed the opex to be increased purely for identified step changes.... If the AER were to depart from this approach it would need to demonstrate why it has done so, as such a departure poses a significant risk for consumers.[2]

The EUCV also submitted that Victorian DNSPs have requested a large (30 per cent) increase in the allowed opex budget based on the actual 2008 accounts.[3] The EUCV argued that the 2008 base year opex is an inflated amount because the 2008 opex shows only an 8 per cent increase from the average of the first three years of actual opex for the period.[4]

The EUCV further submitted that significantly increased opex proposals are not the result of real step changes imposed on the Victorian DNSPs and there was insufficient and inappropriate justification for the inflated claims.[5] The EUCV stated that the Victorian DNSPs have consistently underspent the allowances granted to them for opex, and that despite underspending these allowances, the Victorian DNSPs have claimed significantly more opex than actually used. The EUCV noted that each DNSP is forecasting a large step increase in opex for the forthcoming regulatory control period.[6]

The EUCV submitted that despite the ESCV axing such a large proportion of the step change claims in the previous review, the Victorian DNSPs were still able to under spend on their opex allowances. The EUCV considered that this clearly indicates the ambit nature of the claims by the DNSPs in regulatory reviews.[7]

The Consumer Action Law Centre (CALC) considered that the forecast opex figures, when compared to the previous actual spend for regulatory periods, highlights that the AER should evaluate operational costs closely to ensure they are efficient and effective.[8]

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1 EUCV, *Australian Energy Regulator, Victorian Electricity Distribution Revenue Reset, Applications from CitiPower, Jemena, Powercor, SP AusNet and United Energy, A response by Energy Users Coalition of Victoria*, February 2010, p. 53; Minister for Energy Resources, Submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–15, p. 1; CALC, *Submission to the review of initial distribution network service providers' proposals for the 2011–2015 regulatory period*, 16 February 2010, p. 3.
2 EUCV, p. 41
3 ibid., p. 60
4 ibid, p.60
5 EUCV, pp. 4 and 61.
6 Ibid., p. 43.
7 Ibid., p. 53.
8 CALC, p. 3.

The Victorian Employers Chamber of Commerce and Industry (VECCI) commented on the Victorian DNSPs' customer communications opex step change proposals regarding outage events, and the use of short message service (SMS) technology, noting that:

> … although it is possible to communicate via existing systems, the [SMS] message may lead to unanticipated or unsafe responses… VECCI submits that, until cost effective mass communication protocols can be established and tested, it is not reasonable to expect customers to be able to receive CPP signals reliably, let alone be sufficiently informed to act on the content of that communication.[9]

The EUCV noted that bushfire related impacts have featured in the step changes proposed by all five Victorian DNSPs, even CitiPower with its CBD and closed urban area. The EUCV stated:

> Significant cost claims have been made as a result of the bushfires—both in direct costs (e.g. increased inspections, clearing, etc) and in indirect costs (e.g. insurance costs, claims from impacted electricity users, etc). There is potential for the DBs to deliberately over-emphasize these costs, and the AER should be rigorous in their assessments of such claims.[10]

The EUCV commented on the selection of growth drivers, expected opex savings generated from an expanding network and the interaction between replacement capex and opex.

The EUCV suggested that a closer examination of the impact the various growth drivers have on opex was required.[11] Specific reference was made to the use of consumption as a driver and the negligible impact on opex from existing customer consumption growth as opposed to the physical extension of the network. The EUCV stated that:

> If the new customers extend the geographical area serviced, then it is likely that the increase will result in more opex. If, however, the increased number result from increasing density of customers (e.g. if a house is pulled down and replaced with units) then the increase in opex is marginal at most.[12]
>
> If the increased demand is purely managed by increasing assets sizes in an existing network (especially if old undersized assets are replaced by larger but new assets) then the increase in demand has little impact on opex required.[13]

The EUCV also recognised that the level of renewal capex is likely to have an impact on opex activity:

> With the increase in capex for refurbishment, there must be a proportionate reduction in opex, as this is what justifies the replacement of old assets with new assets.[14]

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9 VECCI, *Submission to the Australian Energy Regulator on the Victorian electricity distribution service providers' proposals for the 2011–2015 regulatory period*, February 2010, pp. 9–10.

10 EUCV, *Submission to AER*, p. 53.

11 ibid.

12 ibid., p 55.

13 ibid., p 56.

The EUCV was concerned that the AER's overarching approach to materials cost escalation allowed electricity transport businesses 'real' cost increases when other businesses have to operate without them. The EUCV considered that this approach:

- did not subject the Victorian DNSPs to the downward pressures imposed by competition and essentially precluded any requirement for the Victorian DNSPs to improve productivity[15]
- was inconsistent with the objective of achieving efficient costs[16]
- increased the risks consumers face under the regulatory process by allowing larger than CPI adjustments for materials.[17]

The EUCV also considered that the Victorian DNSPs should not be able to increase capex for materials cost escalation for the forthcoming regulatory control period without identifying the level of the materials cost elements implicit within the cost elements of the current regulatory control period.[18]

The EUCV did not support the approach to cost escalation proposed by the Victorian DNSPs, including the approach to setting exchange rates. It noted that there was a tendency for 'the AER to take a conservative view on expected changes'. The EUCV further noted that:

> This conservatism in the exchange rates is significant as it flows to the price expectations for all of the price movements of the other materials the AER has estimated, as the prices of these materials are all quoted in $US.[19]

The EUCV considered that since materials costs were decreasing to levels akin to the long term average, a return to the basic premise of CPI adjustments was warranted.[20]

Finally, the EUCV raised concerns regarding the recognition of productivity gains in the AER's assessment of labour cost escalation. Specifically, the EUCV stated that the ESCV allowed an increase for EGW (electricity, gas and water) wages above inflation to reflect that EGW wages would grow faster than the average productivity of the State. Accordingly, the EUCV contends that the AER should recognize that when State productivity is estimated at more than the growth in EGW wages, the AER should reduce the wages growth element.[21]

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14 ibid., p 49.
15 ibid, p. 30.
16 ibid.
17 ibid, p. 36.
18 ibid., p. 33.
19 ibid., pp. 34–36.
20 ibid., p. 34.
21 ibid., pp. 51–52.

7.5 Issues and AER considerations

7.5.1 Approach to assessment

In determining whether the AER is satisfied that the opex forecast included in the Victorian DNSPs' regulatory proposals reasonably reflects the opex criteria, the AER has had regard to the opex factors as relevant and specifically examined the following opex components which each DNSP proposed:

- ‘base year’ cost, which is typically actual opex in the last known year (that is, the penultimate year) of the current regulatory control period
- any increased opex due to increases in the size of the network (referred to as scale escalation)
- any real cost changes above (or below) CPI over the regulatory control period (referred to as real cost escalation)
- any additional costs related to new or removed regulatory obligations or requirements or changes in the operating environment (referred to as step changes).

Further, in assessing each of these opex components, the AER examined whether:

- 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 reasonably reflect the opex criteria, including with respect to their scope, timing, and costs
- the proposed opex requirement is commensurate with what a prudent business, in the circumstances of each DNSP, would require to achieve the opex objectives.

As noted above, in assessing DNSPs' proposals against the opex criteria, the AER has had regard to the opex factors including benchmarking (clause 6.5.6(e)(4) of the NER) and actual and expected opex (clause 6.5.6(e)(5) of the NER). Appendix I details the techniques the AER has applied in assessing the DNSP proposals, including the use of benchmarking and the trend analysis.

The trend analysis, together with benchmarking the Victorian DNSPs against DNSPs in other jurisdictions, demonstrates that the Victorian DNSPs compare favourably to those in other states. This suggests that the revealed costs of the Victorian DNSPs are a sound base for determining the starting point for evaluating their forecast opex proposals.

The AER considers that the Victorian DNSPs are subject to commercial incentives, both through their governance arrangements and the specific incentive mechanisms of the regulatory framework.[22] As noted in section 7.3.1, the Victorian DNSPs, during the current and previous regulatory control periods, have demonstrated that they continually outperform their opex regulatory benchmarks.

The ongoing incentive for the DNSPs to reduce costs reveals an efficient starting point for the AER's assessment of forecast opex (this is referred to as the 'revealed cost' approach).

This chapter has been structured according to each of the opex components identified above, namely:

- efficient base year costs (consistent with revealed costs)
- scale escalation (changes to opex activity levels due to increases in the size of the distribution network)
- real cost escalation (incorporating real input price changes to ensure the value of the base is maintained in real terms)
- step changes (changes to regulatory or legislative obligations and changes in the operating environment may have cost implications over the forthcoming regulatory control period)

In addition to the four cost components, this chapter includes separate sections on self insurance and debt raising costs.

The forecast opex allowance also includes amounts for the Demand Management Incentive Scheme (DMIS) and Guaranteed Service Level (GSL) payments. The Victorian DNSPs' proposals, a summary of stakeholder submissions, and the AER's considerations and conclusions on the DMIS and GSLs are located in chapters 17 and 15 respectively.

Overall these are the considerations the AER has taken into account in determining whether it is satisfied that the forecast opex reasonably reflects the opex criteria set out at clause 6.5.6(c) of the NER.

7.5.2 Reliance on the DNSPs' revealed costs

The regulatory regime applied to electricity networks is an incentive based CPI-X regime. Under the CPI-X approach to regulation the DNSPs are provided with an incentive to seek cost reductions over time. This incentive to reduce costs is achieved by allowing the DNSPs to retain some of the benefits from any cost efficiencies for a period of time before these efficiencies are passed through to customers.

The AER has established an efficiency benefits sharing scheme (EBSS) such that the DNSPs can retain the benefits of any cost efficiencies for a period of five years,

[22] See chapters 13 and 14.

consistent with the length of the regulatory control period. That is, an objective of the EBSS is to provide the DNSPs' with a continuous incentive to seek costs efficiencies throughout the regulatory control period. Given that the DNSPs have a continuous incentive to seek cost efficiencies, the AER has relied on the 'revealed cost' approach to inform its assessment of the DNSPs' opex forecasts under clause 6.5.6(c) of the NER. In particular, the AER has placed weight on clause 6.5.6(c)(5) of the NER. The AER has also had regard to some benchmarking analysis in accordance with clause 6.5.6(c)(9) of the NER which supports the AER's reliance on the revealed cost approach (refer to appendix I).

In particular, this benchmarking analysis indicates that over time the Victorian DNSPs have achieved cost reductions such that the revealed cost approach can be relied on to establish the base level of opex in assessing the Victorian DNSPs' proposed forecast opex over the forthcoming regulatory control period. While the AER has relied on the revealed cost approach to assess the Victorian DNSPs' opex proposals, the AER has identified a number of factors such that the AER is not able to assume that the Victorian DNSPs' actual expenditure at a particular point in time is efficient. These factors include circumstances where:

- the Victorian DNSPs have outsourced some of their services other than on an arms length basis. The AER cannot presume that these costs are efficient in accordance with clause 6.5.6(c)(9) (refer to chapter 6)

- the Victorian DNSPs' proposed forecast opex will lead to an over allocation of overhead costs in the base year (refer to chapter 6)

- some costs do not reflect efficient costs on the basis that these costs are not related to the provision of distribution services or are not considered to reflect an efficient cost on the basis that this will lead to double counting of costs (refer to chapter 6)

- the Victorian DNSPs' actual expenditure includes movements in provisions such that reported expenditure may not be an accurate representation of the Victorian DNSPs' underlying economic circumstances (refer to chapter 13

- costs that are non-recurrent occur in the base year such that the reported costs will not be representative of efficient costs in the forthcoming regulatory control period (refer to section 7.5.4).

Accordingly, where necessary, the AER has made adjustments to the base year level of expenditure proposed by the Victorian DNSPs to ensure that these underlying costs represent efficient expenditure in accordance with clause 6.5.6(c) of the NER.

The Victorian DNSPs (with the exception of United Energy) adopted the revealed cost approach (subject to increases for scale, inputs and step changes) in establishing their forecast opex for the forthcoming regulatory control period. In contrast, United Energy has not adopted this approach as it has not relied on its actual costs as the starting point to establish its forecast opex requirements over the forthcoming regulatory control period. As United Energy’s approach differs from the other Victorian DNSPs, the AER’s assessment of United Energy’s proposal is considered separately, preceding the AER’s assessment of the other Victorian DNSPs.

7.5.3 United Energy opex forecasting approach

Background on United Energy's transformation to a new business model

United Energy's current business model is centred on:

- a small management structure that conducts strategic management and corporate governance activities both within and through services provided by its parent entity Diversified Utility Energy Trust (DUET)[23]
- a single outsourced contract (its operating services agreement (OSA)) under which the asset management, planning, construction and maintenance of its network is outsourced to Jemena Asset Management (JAM), which is ultimately owned by United Energy's minority shareholder (Singapore Power).[24]

However, the current OSA between United Energy and JAM expires on 31 July 2011 (six months into the forthcoming regulatory period) and United Energy does not intend to renew this agreement. Rather, United Energy states that it is in the process of transforming to a substantially different business model with much of the management, administrative and planning activities being internalised and performed by United Energy (or more precisely, by parties related to United Energy).

Accordingly, the first six months of United Energy's opex forecast are based on its current business model, whereas the remainder of the forecast is based on expected costs under its new business model. That said United Energy has begun to incur transformational costs related to the transfer to its new business model, which are reflected in its current actual costs and forthcoming regulatory control period forecasts.

United Energy states that its 'aggressive' approach to outsourcing pursued under its current business model has achieved significant cost reductions and service improvements.[25] According to United Energy, one of those benefits has been its shielding from cost increases in recent years due to the mostly fixed nature of the opex charge paid to JAM. However, United Energy considers that there are a number of problems with its current business model which its new model seeks to address. These include:

- the reliance on a single contractor
- a lack of strategic capacity and control over its network
- a lack of transparency over costs and

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23 The AER understands that until recently, United Energy did not directly employ any staff. United Energy has until recently sourced only a limited number of management services from a related party—Pacific Indian Energy Services (PIES)—and certain management, investment and financial services from its majority shareholder DUET and a related party—AMP Capital Investors (AMPCI). PIES is jointly owned by United Energy, Multinet and Westnet Gas. United Energy, Multinet and Westnet Gas are both the owners and customers of PIES.

24 United Energy, *Regulatory proposal*, p. xvii.

25 United Energy, *Regulatory proposal*, p. xiv.

- the ‘distrust’ of its business model by the regulator.[26]

United Energy submits that its new business model involves it taking a much greater hands–on approach to managing and planning its network.

As part of internalising its asset management strategy, IT strategy and corporate services functions, United Energy forecasts that the number of employees it directly (or on contract) employs will increase significantly over the next several years. The current JAM contract will expire on 30 June 2011 and the AER notes that the major increase in staff is not expected to occur until 2011. Table 7.7 provides a breakdown of services which are provided internally and services which are outsourced under the new business model.

Table 7.7 In-house and outsourced functions under United Energy’s new business model

Function	In-house includes:	Outsourced includes:
Network management	Development of asset management plans and work programs Network planning Maintenance planning	Operations services Control centre operations
Customer and market management	Business development AIMRO contract management Management of key end users and stakeholders	Customer contact centre services AIMRO program management office
IT services	IT strategy and architecture IT service delivery management	Infrastructure and applications management IT project and management services
Corporate services	Business development Legal and key contract management Regulatory services Finance HR and admin	Not outsourced

Source: United Energy, *Regulatory proposal*, pp. 22–23.

The AER notes that United Energy has almost completed a tendering process for the period after its contract with JAM expires, even though the current contract does not expire until 30 June 2011. As noted above, the outcomes from the tender process in

[26] United Energy, *Regulatory proposal—Appendix F3 ('Project Seven 11 commercial & regulatory strategy', United Energy board paper, 14 April 2009);* United Energy, *Regulatory proposal—Appendix F4 (AT Kearney, Business model review).*

relation to the unit costs of outsourced services form the basis of part of United Energy's opex forecast in its regulatory proposal.

United Energy considers that it undertook what it describes as a ‘best of breed’ tendering approach, where specialist contractors in different areas (e.g. construction, IT) were encouraged to form a consortium and bid against competing consortia. United Energy received responses from four consortia who wanted to participate in the final stage of the tender process. The AER notes that United Energy has selected its preferred tenderer and refers to the winning applicant as its ‘turnkey service provider’.[27]

As part of its new business model, United Energy has advised that it will be separating its network into two geographical regions (i.e. northern and southern regions). The turnkey service provider will manage and operate one of those regions however the other region will be awarded to some other party. In addition, the consortium partner will provide customer and market management and IT services for both regions. In ‘phase 1’ of the transformation the turnkey service provider is responsible for managing all of the contracts including its own and the second regional contract. In ‘phase 2’, it is intended that United Energy will take over management of the second regional contract. Eventually in ‘phase 3’ United Energy anticipates that it will take over the direct management of all the contracts including those held by the turnkey service provider. United Energy’s proposal appears to assume ‘phase 2’ occurs in year three of the forthcoming regulatory control period. However the AER notes that the timing of phases 2 and 3, and the decision as to whether they even occur, is at the discretion of United Energy and is not prescribed by the new contract with its turnkey service provider.[28]

The AER notes the current JAM contract includes a clause giving JAM a ‘right to match’ the terms of any future contract. Accordingly, if JAM exercises its right to match then it will become the turnkey service provider and the winning applicant will take the contract for the second regional network. JAM has not yet indicated whether or not it will exercise its right to match. The AER also notes that this process is subject to a contract dispute between United Energy and JAM over the correct interpretation of the right to match clause.[29]

United Energy's proposed opex forecast

United Energy describes its forecast as having:

> …been developed from a rigorous competitive tender exercise in relation to the costs of outsourced services, and a detailed bottom-up build in relation to the costs of in-house service provision.[30]

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27 United Energy, *Regulatory proposal—Appendix F4 (AT Kearney, Business model review).*

28 United Energy, *Regulatory proposal—Appendix F4 (AT Kearney, Business model review).*

29 United Energy, *Regulatory proposal—Appendix F5 ('UED Project 7/11—Final recommendation', Board paper).*

30 United Energy, *United Energy response to the AER's queries on operating expenditure,* 29 March 2010, p. 1.

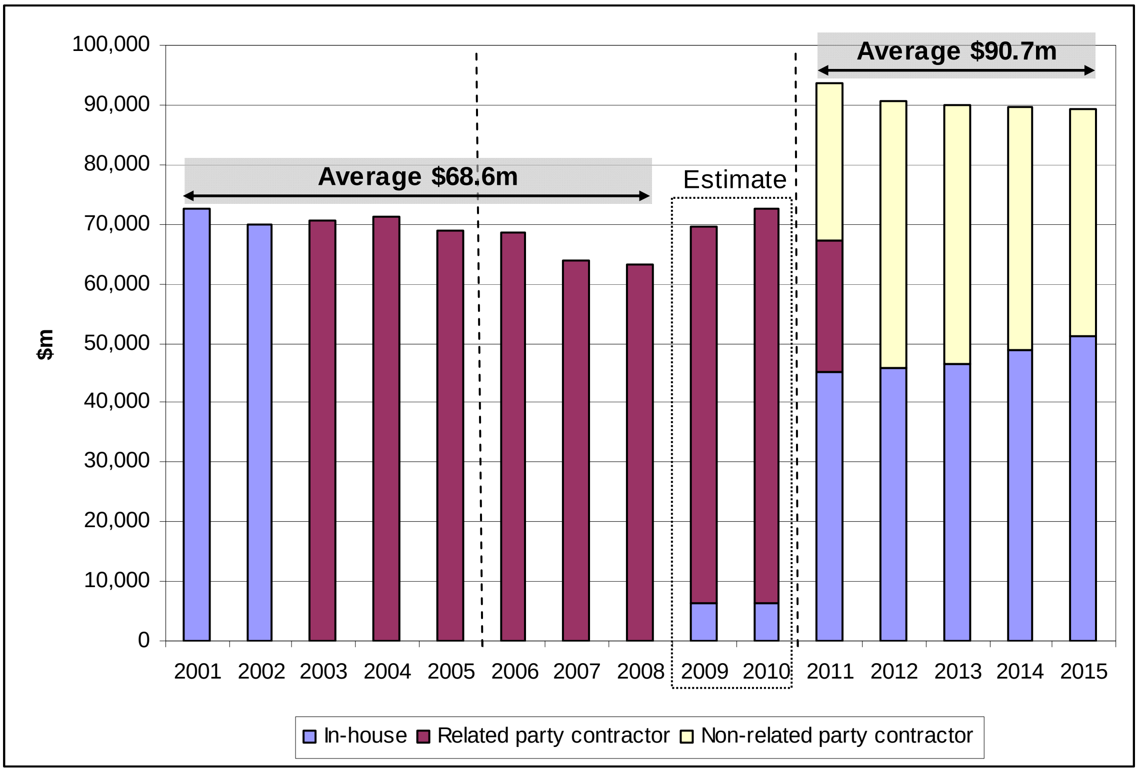
In addition, United Energy has submitted a 'reference line' forecast of operating costs if it were to continue its current business model and compared this against the forecast costs under its new business model.

United Energy's operating and maintenance forecast can be separated into four distinct components:

- unit costs associated with tendered services
- unit volumes associated with tendered services
- unit costs associated with services provided internally or through related parties
- unit volumes associated with services provided internally or through related parties.

Figure 7.2 presents the operating component of United Energy's historical and forecast operating expenditure, split between whether the cost is incurred internally or through related or non-related party contractors.

Figure 7.2 Comparison of United Energy's historical, estimated and forecast operating expenditure (real $2010)



(a) Figure 7.2 does not include maintenance costs as United Energy's regulatory proposal does not split these costs between in-house, related party contractor and non-related party contractor provision.

Source: United Energy, RIN templates, 30 November 2009.

AER considerations

United Energy states that its 'operating expenditure forecasts reflect the outcome of a rigorous, competitive tender process to replace the existing OSA'.[31] In effect, United Energy appears to argue that as its forecast opex has been market-tested it can be relied upon to reflect efficient costs without further assessment. However, the AER notes that it is essentially only the tendered unit costs which have been market-tested with the other three components of its opex forecast estimated by United Energy. As outlined in section 6.6.4, the AER has reviewed the tendering process and is reasonably satisfied with the competitiveness of this process. However, the AER has concerns with each of the remaining three components of United Energy's bottom up estimate of its costs which have not been market tested.

While the unit costs associated with outsourced services have been determined via tender, the unit volumes associated with these services have been estimated by United Energy. A KPMG report submitted by United Energy states that United Energy sourced information from Jemena and internally to determine the forecast volumes of operating and maintenance work on its network.[32] However, few details are provided on this information and the information itself was not submitted by United Energy with its regulatory proposal. The AER also notes that United Energy has not provided historical volume information with its proposal nor demonstrated either how its forecasts are consistent with historical patterns, or why they differ from historical levels if this is the case. The AER considers that the forecast volumes associated with outsourced activities have not been substantiated in United Energy's regulatory proposal.

The AER notes that United Energy's internal opex forecasts were constructed at a highly detailed level—the salaries of each individual employee (plus on costs) was forecast over the forthcoming regulatory control period then aggregated. However, yje AER considers that this high level of specification is not robust because of the significant degree of estimation involved in this forecast which has not been sufficiently supported.

United Energy used an internal corporate budgeting model to estimate the in-house cost component of its opex forecast.[33] The AER assessed the model inputs, which mostly consist of staffing numbers, salary estimates and estimates of corporate overhead costs (e.g. insurance).

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31 United Energy, *Regulatory proposal*, p. 43.

32 United Energy, *Regulatory proposal—Appendix C1 ('KPMG and Johnson Winter & Slattery, United Energy Distribution—Forecasting methodology for operating and capital expenditure, November 2009')*, pp. 73–75.

33 The internal corporate budgeting model used by United Energy to estimate its internal costs was not submitted as part of United Energy's proposal. The AER sought and received this model from United Energy, though initially with the main input into the model deleted (being the salary inputs) and the outputs from the model being 'hard-coded' in and not derived from the model itself. The AER sought the working version of the model used by United Energy to derive its forecast internal opex. This was provided by United Energy. United Energy, *Scott Sandles e-mail—Internal budget 5 year model*, Email to AER, 16 February 2010; United Energy, *Scott Sandles e-mail 5 Feb—Question 4*, Email to AER, 16 February 2010.

In its regulatory proposal, United Energy listed but did not provide the source material it stated was used to establish the number and roles of staff it plans to hire in the future.[34] The AER requested United Energy provide each source material listed in its proposal and an explanation of how this material was taken into account in deriving United Energy's forecast. United Energy provided the source material and an explanation, however the link between the source material and the proposed employee numbers has not been well established by United Energy.

On the salary estimate inputs, United Energy provided economy-wide and utility industry salary benchmark reports published by various recruitment firms (e.g. Hays, Hudson).[35] While United Energy has submitted these reports subsequent to its proposal, it has not clearly demonstrated the link between the reports and the salary estimates in its internal corporate budgeting model.[36] Additionally, United Energy's internal cost forecasts include a 15 per cent salary bonus for most staff which has not been explained or substantiated.

In summary, the AER is satisfied that one component of United Energy's opex forecast (the tendered unit costs) reasonably reflect the efficient costs of a prudent operator. These unit costs have been established through a reasonably competitive tender process. However, the AER is not satisfied that the remaining three components (being the internal unit costs, internal unit volumes, and unit volumes associated with outsourced services) reflect efficient costs that would be incurred by a prudent operator in United Energy's circumstances, or a realistic expectation of input costs. These inputs were not well substantiated in United Energy's proposal or in the subsequent information received by the AER.

Table 7.8 summarises the AER's overall assessment of the different components of United Energy's opex forecast.

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[34] United Energy's regulatory proposal stated that the forecast staffing numbers were built up from its Resource Plan. It states the forecast staffing numbers were based on assumptions of the number of resources that United Energy estimates it will need to operate its new business structure. United Energy listed the source material from which these assumptions were based on as United Energy's 2002 (pre-OSA) organisation charts, JAM's 2009 organisation charts, a review of JAM resources allocated to the United Energy business in 2009, a number of utility benchmarks from Europe, an examination of staffing levels and organisation structures of other Australian distribution businesses, and analysis and reviews by United Energy's functional heads. United Energy, *Regulatory proposal*, pp. 55–56.

[35] United Energy, *AER information request on UED's operating expenditure forecasts*, Letter to AER, 12 March 2010

[36] The AER notes that the reports were not commissioned by United Energy in the context of its business transformation or regulatory proposal but are rather reports which are published regularly by recruitment firms.

Table 7.8 AER draft decision—Assessment of different components of United Energy's opex forecast

Component of forecast	AER assessment
Outsourced services—unit costs	Unit costs derived from reasonably competitive tender process.
Outsourced services—unit volumes	Unit volumes estimated by United Energy. Not sufficiently substantiated.
In-house services—unit costs	Unit costs estimated by United Energy. Source material provided at request of AER subsequent to lodgement of regulatory proposal. Connection between source material and forecast not clearly established.
In-house services—unit volumes	Unit volumes estimated by United Energy. Source material provided at request of AER subsequent to lodgement of regulatory proposal. Connection between source material and forecast not clearly established.

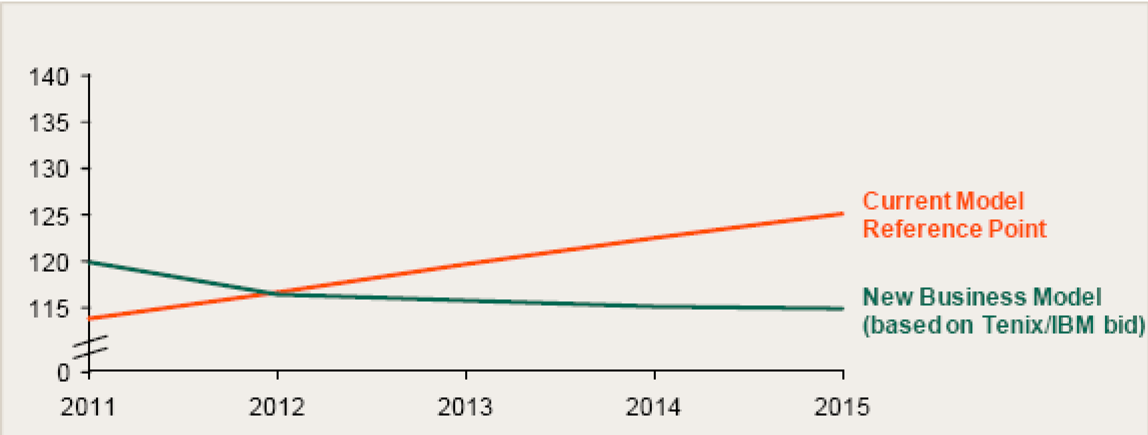
Source: AER analysis

In addition to the above, United Energy also seeks to recover the forecast transformational costs associated with the move to its new business model. These transformation costs include the upfront costs of implementing new business processes and systems, and meeting the costs of redundancies associated with gaining efficiencies.[37] The AER notes that United Energy's modelling appears to mistakenly include the forecast transformational costs from the first six months of 2016, which is beyond the forthcoming regulatory control period.

As noted above, United Energy has also submitted a 'reference line' estimate of what it considers its opex would have been in the forthcoming regulatory control period if it had remained with its current business model, and compared this against the forecast operating costs in its regulatory proposal. This reference line estimate is presented in figure 7.3.

[37] United Energy, *Regulatory proposal*, p. 17.

Figure 7.3 United Energy proposal—Comparison of proposed opex forecast under new business model compared with estimated opex under the continuation of its current business model



Source: United Energy proposal

The AER has identified several issues with the calculation of United Energy's reference line estimate.

The 'base year' estimate from which the reference line is forecast overstates the costs United Energy would incur under the continuation of its current business model due to the inclusion of transformational costs currently being incurred by United Energy in transitioning to its new business model.

In addition, United Energy assumes that a continuation of its current business model would result in an increasing cost profile over the forthcoming regulatory control period. This increase results from United Energy applying the 'rate of change' factor adopted by the ESCV in the EDPR for the current 2006–10 regulatory control period. The adoption of this rate of change assumption is the sole factor resulting in an increasing cost under United Energy's 'reference line' forecast. United Energy states that it adopted this assumption in the absence of its own estimates.[38] However, the AER considers that it is unlikely this rate of change assumption results in a realistic forecast for the 2011–15 regulatory control period, given it was only intended to be a forecast for the 2006–10 regulatory control period. Further, the AER notes that United Energy's new business model forecast has a minimal increasing cost profile (after 2012). United Energy states that this profile is driven by the forecast cost assumptions build into the tendered unit costs of the winning application from its tender. Accordingly, the different cost profiles would imply that JAM is expected to face a rising cost profile over the forthcoming regulatory control period whereas the winning tender application is expected to face a much lower cost profile. United Energy has not presented the AER with information that would demonstrate that it is reasonable to assume that JAM and the winning tender applicant would have differing cost profiles. The AER notes that United Energy itself does not purport that the reference line estimate demonstrates its opex forecast meets the requirements of the NER. In

38 United Energy, *United Energy response to the AER's queries on operating expenditure*, 29 March 2010, p. 7.

response to some questions from the AER on the reference line estimate, United Energy stated:

> The AER appears to have formed an incorrect view that the reference line is central to UED's operating expenditure forecast and its demonstration that it is prudent and efficient.[39]

Accordingly, given the issues with the calculation of the reference line estimate identified by the AER and the qualifications on its purpose and usefulness as described by United Energy, the AER is not satisfied that the comparison of the reference line estimate against United Energy's opex forecast demonstrates that United Energy's opex forecast reasonably reflects efficient costs that would be incurred by a prudent operator in United Energy's circumstances, or a realistic expectation of input costs.

AER conclusion

In summary, the AER considers that United Energy conducted a reasonably competitive tender process and so the unit costs for outsourced services arising from this tender reasonably reflect efficient costs. However, these unit costs are only one of four components of United Energy's opex forecast. The AER considers that the reasonableness of the other three components (in-house unit costs, in-house unit volumes, out-sourced unit volumes) has not been substantiated in United Energy's proposal or in the additional information provided by United Energy in response to the AER's information requests.

In particular, due to the issues identified above in relation to the 'reference point' estimate, and the qualifications placed on this estimate by United Energy, this top-down analysis does not demonstrate the efficiency or prudence of United Energy's new business model (or at least, United Energy's opex forecasts under its new business model).

As United Energy's forecast opex is derived from these four components, the AER is not satisfied that United Energy's opex forecast reasonably reflects the opex criteria. Specifically, the AER is not satisfied United Energy's opex forecast reasonably reflects the efficient costs, costs that would be incurred by a prudent operator in the circumstances of United Energy or a realistic expectation of input costs required, to achieve the opex objectives. Under the NER, the AER must not approve United Energy's forecast, and must instead replace it with an estimate of the required opex that the AER considers meets the opex criteria.[40]

In summary, the AER's estimate of the required opex, which is the minimum adjustment it considers necessary to be in accordance with the requirements of the NER,[41] is derived from:

- a 'base year' opex derived mostly from the historical actual expenditure of operating United Energy's network under its current business model

[39] United Energy, *United Energy response to the AER's queries on operating expenditure*, 29 March 2010, p.2.
[40] Clause 6.12.1(4)(ii)
[41] Clause 6.12.3(f).

- adjusted for scale, real cost escalators and step changes in the same manner as for the other Victorian DNSPs.

The AER's assessment is provided in sections 7.5.4, 7.5.5, 7.5.6 and 7.5.7.

7.5.4 Base year opex

Selection of base year

Relevant to assessing and determining whether the Victorian DNSPs' proposed forecast opex allowance for base year costs reasonably reflects the opex criteria are the following opex factors, which the AER has specifically had regard to:

- The actual and expected opex of the Victorian DNSPs during the current regulatory control period.[42] The revealed cost approach relies on the incentive properties of the regulatory regime to provide an efficient starting point for forecast opex based upon adjusted actual opex from the current regulatory control period. The analysis presented in this section, in particular the adjustment of actual opex (where available) for factors such as non-recurrent cost and related party margins, has been taken into account in determining the AER's estimate of the Victorian DNSPs' required opex for the forthcoming regulatory control period which satisfies the opex criteria.

- Benchmark opex that would be incurred by an efficient DNSP over the regulatory control period.[43] The AER has undertaken trend analysis, together with comparative benchmarking of Victorian DNSPs with DNSPs in other jurisdictions.[44] This analysis is presented in appendix I. The results reveal that the Victorian DNSPs compare favourably to those in other states, which suggests that the revealed costs of the Victorian DNSPs is a sound base for determining the starting point for evaluating their regulatory proposals.

- The extent to which the forecast of required opex of the DNSP is referable to arrangements with a person other than the service provider that, in the opinion of the AER, do not reflect arm's length terms.[45] The AER has considered the issue of related party margins, with CitiPower, Powercor, Jemena, SP AusNet and United Energy contracting out certain services to a related party service provider.

In addition to the specific opex factors noted above, the AER in providing the Victorian DNSPs with a forecast opex allowance inclusive of base year costs, provides the DNSPs' with a total forecast opex allowance reflects the efficient costs of achieving the opex objectives and the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives.

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42 Clause 6.5.6(e)(5) of the NER.
43 Clause 6.5.6(e)(4) of the NER.
44 Cause 6.5.6(e)(5) of the NER
45 Clause 6.5.6(e)(9) of the NER.

With the exception of United Energy, the Victorian DNSPs proposed 2009 as their base year.[46] However, at the time of lodgement of their regulatory proposals, the Victorian DNSPs' actual 2009 costs were not available. Instead, the Victorian DNSPs' proposals contained estimates of 2009 actual costs.

CitiPower and Powercor submitted that 2009 is the most efficient base year because it will:

- include the most recent year of actual outturn data
- best reflect the impact of the economic conditions that are likely to prevail during the 2011–15 regulatory control period
- align CitiPower's and Powercor's opex forecasts with the operation of the efficiency carryover mechanism that applies in the current regulatory control period.[47]

SP AusNet submitted that the 2009 opex is efficient because:

- SP AusNet has responded to the incentives provided by the efficiency carryover mechanism
- its 2009 opex is consistent with its 2008 opex
- SP AusNet’s opex compares favourably to its peers
- its 2009 opex reflects the circumstances (for example, weather events, exogenous events) that could reasonably be assumed to occur over the forthcoming regulatory control period.[48]

Jemena proposed to adopt its 2009 costs as the base year for its opex forecast and submitted that this base year approach is consistent with the incentive provisions inherent in the ESCV’s efficiency carryover mechanism and the AER’s EBSS mechanism.[49]

As discussed in section 7.5.3, United Energy has not forecast its opex from a base year.

Submissions

The Energy Users Coalition of Victoria (EUCV) submitted that the Victorian DNSPs have requested a 30 per cent increase in the allowed opex budget based on the actual 2008 accounts.[50] The EUCV argued that the 2008 base year opex is an inflated

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46 United Energy did not propose a base year and instead proposed an opex forecast based on a forward looking estimate of its costs which was decoupled from its historical costs.

47 CitiPower *Regulatory Proposal*, pp. 163–164; Powercor Regulatory Proposal, pp. 159–160.

48 SP AusNet *Regulatory Proposal*, pp. 193–194.

49 Jemena *Regulatory Proposal*, p. 125-6.

50 EUCV, *Australian Energy Regulator, Victorian Electricity Distribution Revenue Reset, Applications from CitiPower, Jemena, Powercor, SP AusNet and United Energy, A response by Energy Users Coalition of Victoria*, February 2010, p. 60.

amount because the 2008 opex shows an 8 per cent increase from the average of the first three year actual opex for the period.

AER considerations

The AER has adopted a revealed cost approach consistent with the approach proposed by CitiPower, Powercor, Jemena and SP AusNet to estimate the efficient operating and maintenance expenditure of the Victorian DNSPs over the forthcoming regulatory control period. Accordingly, the AER has adopted a base year from which to assess the Victorian DNSPs' forecast opex for the forthcoming regulatory control period.

The base year selected by the AER is typically the most recently available year, within the current regulatory control period, for which actual expenditure is available. The AER's choice of base year reflects the view of CitiPower, Powercor and SP AusNet that the last year of actual costs is likely to represent an efficient level of expenditure given the incentives for DNSPs to reduce costs under the regulatory framework. In addition, the application of an ECM/EBSS provides the AER with some confidence that the last known year of actual costs is reflective of efficient costs in that year.[51]

Subsequent to their initial proposals, CitiPower, Powercor and Jemena provided their unaudited 2009 actual expenditure. SP AusNet provided an extract of its unaudited 2009 expenditure. United Energy did not provide any such updates. That said all of the Victorian DNSPs' provided their audited 2009 actual expenditure on 30 April 2010.

However, the Victorian DNSPs' audited actual expenditure has been available late in the process, the AER in its draft decision has had regard to the unaudited 2009 costs rather than the audited expenditure (or in the case of SP AusNet, an extract of its accounts) where these have been made available by the DNSPs.[52] The AER has used Jemena's estimated costs in its regulatory proposal as its unaudited 2009 costs were provided too late in the process to be considered in this draft decision. However, the Victorian DNSPs' reported or estimated base year costs have been used by the AER as a placeholder for the Victorian DNSPs' audited 2009 costs to which the AER will have regard to establishing the base year level of expenditure for its final decision. To the extent that there are differences between these costs and the audited 2009 expenditure, the AER will assess these differences and where necessary, apply the adjustments detailed in the following sections and in the chapter 13 for its final decision.

For the purposes of determining United Energy's base year (2009) costs under its current business model, the AER has considered several source materials. In particular, the AER has considered United Energy's regulatory accounts, RIN templates and a cost build-up based on different sources.

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51 An objective of the EBSS is to provide a continuous incentive for the DNSPs to minimise costs throughout the regulatory control period.

52 The DNSPs were invited to provide the unaudited regulatory accounts for 2009. Powercor and CitiPower provided unaudited accounts on 10 March 2010, SP AusNet provided an extract of its unaudited accounts on 17 March 2010 and Jemena provided its unaudited accounts on 14 April 2010. United Energy did not provide its unaudited regulatory accounts.

While the AER has adopted the regulatory accounts to determine the base year for other Victorian DNSPs (adjusted as necessary), the AER does not consider that this is appropriate for United Energy. The reasons are that:

- Other Victorian DNSPs submit regulatory accounts which exclude the profit margin paid to related parties, whereas United Energy's regulatory accounts include margins.

- United Energy claims that JAM is currently making a loss in servicing United Energy's network, resulting in a 'negative margin'. Accordingly, United Energy's regulatory accounts expenditure (which are inclusive of this negative margin) would actually understate JAM's actual costs in servicing United Energy's network and so not be representative of the actual underlying costs of United Energy's current business model.

- United Energy's actual 2009 costs (as reflected in the regulatory accounts) will include a significant amount of costs associated with its transition to the new business model.

The AER has also considered United Energy's 2009 opex estimate from the RIN template. However the AER has not adopted this approach to establishing the base level of opex. This is because the AER is unable to reconcile United Energy's historical expenditure, excluding margins, with any source material. Further, the AER notes that in terms of reconciling the RIN expenditure with other material submitted by United Energy, United Energy has been unable to perform this reconciliation.[53] The AER also considers that the adoption of the 2009 RIN template expenditure would be problematic due to the inclusion of transitional costs associated with its new business model.

Accordingly, the AER has determined United Energy's base year opex on the summation of two sources:

- JAM's costs in 2008 of servicing United Energy's network, as reported by JAM to United Energy and verified by PriceWaterhouseCoopers (PWC) (subject to the exclusion of certain cost categories allocated to United Energy, as discussed in sections 6.7.1 and 6.7.3). The AER notes that these PWC reports are the starting point used by United Energy to complete its regulatory accounting statements and the AER considers these reports reliable. Further, these costs do not include transitional costs associated with United Energy's new business model.

- United Energy's 2009–10 internal costs as provided in its internal corporate opex budgeting model, with the costs associated with its new business model removed. While these costs are estimates, they have the benefit of being a bottom up construction from individual cost categories. Accordingly, the AER has been able

[53] United Energy, *United Energy response to the AER's queries on operating expenditure*, 29 March 2010, p. 4.

to review the model line-by-line and remove transitional costs and other costs associated with United Energy's new business model.[54]

The AER did not include within this base year estimate the management and financial services fees that United Energy forecasts it will pay its related parties (DUET and AMP Capital Investors) over the forthcoming regulatory control period. The AER's reasons for this exclusion are set out in section 6.7.1.

The AER will update United Energy's base year costs for its final decision following consideration of JAM's 2009 costs of servicing United Energy's network.

Base year costs

CitiPower proposed that that there are no non-recurrent or one-off costs that should be excluded from its 2009 operating expenditure base year.[55] Powercor proposed that the only non-recurrent costs included in its base year related to an Australian Tax Office audit.[56]

Jemena identified a number of costs which they considered are not representative of a typical year of recurrent opex. Subject to these adjustments, Jemena considered that its base year costs were representative of a typical year and therefore suitable as a basis for forecasting purposes.[57]

SP AusNet proposed that to produce forecasts of efficient opex for the forthcoming regulatory control period, it is appropriate to remove costs from the 2009 base year costs to account for three issues:

- bushfires and heatwave events
- defined benefit actuarial adjustments
- related party margins.[58]

AER considerations

The AER considers that adjustments to the base year costs proposed by the Victorian DNSPs are necessary to ensure that these costs reflect efficient costs in accordance with clause 6.5.6(c) of the NER. In assessing the Victorian DNSPs'

54 Generally speaking, in determining the salary and contract staff forecasts the AER has incorporated those staff that United Energy's model indicates were employed in the September quarter 2009 being the initial time period in the model. Additionally the AER excluded the 'salaried staff—regulatory services', 'professional services costs—finance, HR and admin' and 'licenses' categories from the AER's estimate. The first category was excluded as the 2008 JAM costs will include regulatory services costs for United Energy (the regulatory function was not transferred from JAM to PIES until 2009). The second category was excluded as it appears to be for costs already included in the debt raising cost allowance. And the third category was excluded as licence fees are compensated for through the form of control. Additionally, the AER adjusted the 'insurance' cost category to exclude United Energy's proposed step change in insurance costs which is considered separately to the base opex.

55 CitiPower *Regulatory proposa*l, p. 148

56 Powercor *Regulatory proposal*, p. 227

57 Jemena *Regulatory Proposal*, p. 132.

58 SP AusNet *Regulatory Proposal*, pp. 205–206.

proposed base year costs the AER, as discussed above, has had regard to CitiPower and Powercor's unaudited 2009 costs, and an extract of SP AusNet's unaudited 2009 costs (and 2009 estimates for Jemena and United Energy). The AER will have regard to the Victorian DNSPs' audited 2009 costs for its final decision. However, the AER considers that will be necessary to adjust the Victorian DNSPs' audited 2009 base year costs for the following factors:

- related party margins
- movement in provisions
- distribution licence fees
- a reallocation of costs to AMI services (relevant only to CitiPower and Powercor).[59]

The AER's basis for applying these adjustments is discussed in chapter 6 and chapter 13. The AER also considers that it is necessary to adjust the Victorian DNSPs' reported base year expenditure for the following:

- guaranteed service level (GSL) payments
- avoided distribution cost related payments
- an over allocation of the related party's corporate costs to the DNSP (refer to chapter 6)
- management fees paid to the parent of the related party (and the DNSP) that are not an efficient cost and a cost that would not be incurred by a prudent operator, or management fees that may not sufficiently contribute to the provision of distribution services (refer to chapter 6)
- corporate cost categories that may double count costs recovered elsewhere in the regulatory regime (for example, debt raising costs) or other corporate cost categories that do not sufficiently contribute to the provision of distribution services or are not an efficient cost that would be incurred by a prudent operator (refer to chapter 6)
- where necessary, the removal of non-recurrent costs to ensure that the base year costs are representative of efficient costs
- any changes in capitalisation policy between the current regulatory control period and the forthcoming regulatory control period.

The AER’s consideration of these issues is discussed below with the exception of issues related to cost allocation and corporate costs which are considered in chapter 6.

[59] These adjustments have also been applied to 2006, 2007 and 2008 to ensure that efficiency carry over reflects expenditure on a like for like basis.

Related party margins

The Victorian DNSPs' proposed forecast opex inclusive of related party margins for the forthcoming regulatory control period. As discussed in chapter 6, the AER proposes to exclude related party margins from the Victorian DNSPs' opex forecasts. Accordingly, the AER in its draft decision has adopted CitiPower's and Powercor's unaudited accounts exclusive of related party margins. The AER has also not included a margin for United Energy related to its outsourcing costs (refer to chapter 6). The AER will have regard to the Victorian DNSPs' audited 2009 accounts exclusive of margins to establish the base level of opex for the draft decision.

Movement in provisions

The AER will remove, where necessary, the effect of any movement in provisions in the Victorian DNSPs' audited 2009 accounts.

Distribution licence fee

The Victorian DNSPs' distribution licence fees will be recovered on an annual basis through the weighted average price cap. As these costs will be reported in the Victorian DNSPs' audited 2009 accounts, the AER will exclude these costs from the Victorian DNSPs' base year expenditure.

Reallocation of costs to AMI services

In its AMI review, the AER accepted re-audited regulatory accounts from CitiPower and Powercor in setting CitiPower and Powercor's AMI budgets and charges for 2009–11. The AER notes that CitiPower and Powercor have now proposed further amendments to these re-audited regulatory accounts. The AER has not accepted these further amendments to these re-audited regulatory accounts on the basis of its decision in the AMI review that it will only have regard to audited regulatory accounts. Accordingly, the AER will review CitiPower and Powercor's audited 2009 accounts for its final decision and, where necessary, will make an adjustment to remove any AMI related adjustments.

Guaranteed Service Level payments

The Victorian DNSPs' estimated GSL payments in 2009 are excluded from the base year opex as these costs are not representative of the GSL allowance for the forthcoming regulatory control period. The AER has provided the Victorian DNSPs with a GSL allowance for the forthcoming regulatory control period based on an average of the DNSPs' actual payments over 2005–09, as set out in chapter 15. The AER, where necessary, will update this adjustment to the Victorian DNSPs' base year costs for the actual GSLs paid in 2009 in its final decision.

Avoided distribution cost payments

The AER is aware that some of the Victorian DNSPs incur avoided distribution related costs. These costs reflect payments that are made to embedded generators within the distribution network (for example, Jemena incurs payments related to the Somerton generator). As the AER has relied on or proposes to rely on the Victorian DNSPs' audited regulatory accounts as the starting point to establish the Victorian DNSPs' opex forecasts, the AER will require the Victorian DNSPs to provide forecast expenditure associated with any avoided distribution cost payments to embedded generators. This is necessary as these costs need to be separately identified to ensure that the EBSS excludes opex related to these non-network activities.

Non-recurrent costs

Regulatory reset costs

The AER notes that, in general, the regulatory costs incurred by the Victorian DNSPs related to regulatory resets can be significantly higher, particularly over the last two years of a regulatory control period. The AER considers that where the base year used to estimate forecast opex is the penultimate year of the regulatory control period, as is the case for the Victorian decision, an adjustment should be made to remove these reset costs from the base year given that these additional costs are not expected to be incurred in every year of the forthcoming regulatory control period.

Accordingly, the AER has removed regulatory reset costs from the base year opex for the Victorian DNSPs, with the exception of SP AusNet.[60] The AER has provided the Victorian DNSPs with some reset costs in 2014 and 2015 which reflects the period in the forthcoming regulatory control period where some additional regulatory costs will be incurred (refer to section 1.5.7).

ATO audit costs

Powercor submitted that an ATO audit was conducted during the current regulatory control period, and that this event was not expected to recur in the forthcoming regulatory control period.[61] Powercor excluded the ATO audit costs of $2.3 million ($2010) from the 2009 base year.

Superannuation payments

SP AusNet proposed to remove from its base year forecasts the amount charged by its service provider, SPIMS, during the 2009 calendar year for actuarial adjustments to the SPIMS employees' defined benefit superannuation plan. SP AusNet stated that:

> Following the 2008 amendments to the management services agreement, the employee costs that SPIMS on-charge to SP AusNet for management services has included the cost associated with actuarial gains / losses on the superannuation plan recognised by SPIMS during the preceding period. These gains / losses reflect the difference between the outputs provided by the actuary ex ante, which in turn are based on the assumptions for parameters such as pay increases and financial market conditions etc, as well as the actual outcomes for the period.[62]

SP AusNet also submitted that it proposes to remove this charge from its 2009 actual regulated opex, and exclude these costs from its 2009 regulatory accounts along with all future regulatory accounts.[63]

Powercor also submitted that its contribution to the defined benefit scheme has been very volatile with turbulent market conditions during the last couple of years. Powercor stated that it made no contributions in 2006 and 2007 and the deteriorating

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60 SP AusNet provided evidence that its regulatory costs have not materially fluctuated over the current regulatory control period and that it would not experience a significant increase in expenditure in its base year.

61 Powercor, *Regulatory proposal*, p. 227.

62 SP AusNet, *Regulatory proposal*, p. 205.

63 ibid., p. 205

financial conditions have reduced the value of investments in these defined benefits schemes, leading to an increase in contributions for 2009.[64]

The AER considers that fluctuations in required superannuation contributions are likely to be broadly symmetrical as financial market conditions are likely to fluctuate such that any actuarial adjustments are likely to balance out over time. That said the AER considers that the impact of the recent global financial crisis was such that any actuarial adjustments related to defined benefit scheme contributions reflected in the reported base year costs are unlikely to be consistent with the level of costs expected to occur in the forthcoming regulatory control period. To ensure the reported base year costs are reflective of an efficient level of expenditure, the AER requires that the Victorian DNSPs identify any actuarial adjustment in 2009 where these adjustments are included in the Victorian DNSPs' regulatory accounts.

The AER has removed SP AusNet’s actuarial adjustment of $3.0 million ($2010) from its base year opex.[65] The AER has estimated Powercor’s and CitiPower's actuarial adjustment to be $5 million ($2010) and $1.7 million ($2010) respectively, and the AER has removed these amounts from Powercor's and CitiPower’s base year opex. This adjustment is based on the difference between Powercor’s estimated cost of $10 million ($2010) in 2009 and its average costs over 2006–08. The AER will require CitiPower and Powercor to identify the actuarial adjustment for its final decision and whether this adjustment is included in its regulatory accounts.

Jemena and United Energy did not propose any downward adjustments to base opex for any actuarial adjustments to their employee defined benefits schemes. For its final decision, the AER will also require Jemena and United Energy to identify whether actuarial adjustments are included in their regulatory accounts and if so, the actuarial adjustment that is reflected in the 2009 regulatory accounts.

Bushfire and heatwave costs
SP AusNet submitted that forecasts of efficient opex for the forthcoming regulatory control period should exclude costs from the base year related to the February 2009 bushfires and heatwave events.[66] Specifically, SP AusNet stated that:

> [i]n relation to the bushfire expenditure, whilst the prudency of this expenditure in the 2009 year is unquestionable, it is unlikely that events of the magnitude in 2009 will occur on a regular basis.

The AER has removed these costs from SP AusNet’s base opex for the draft decision. The AER also requires Powercor to confirm that is has not incurred any non-recurrent costs associated with the February 2009 bushfires.

Jemena Limited and Jemena Asset Management
The AER notes that Jemena has recently implemented a whole of business cost allocation method (referred to as WOBCA), that determines the allocation of Jemena Limited and JAM's cost of services to Jemena and United Energy as well as other

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64 Powercor, *Regulatory proposal*, p. 226.
65 SP AusNet, *SP AusNet response to AER's further information request on provision of unaudited 2009 regulatory accounts*, March 24 2010, p. 1
66 SP AusNet, *Regulatory proposal*, p. 205.

assets.[67] Further, this method also identifies whether costs are expected to be non-recurrent.[68]

Jemena proposed a number of costs, allocated by its WOBCA method, which were identified as being one-off in nature.[69] These costs included branding; SPI employee costs; One-IT; Dove/Warrnambool; BPR blueprint; network support payments; accounting one off payments; and other costs.[70]

The AER accepts that the costs proposed by Jemena are non-recurrent, and notes that these costs, totalling [c-i-c] million ($2010) have been excluded from Jemena's base year opex.[71] The AER also notes that the WOBCA method allocated costs to other assets, including United Energy.[72] Further, the AER considers that given it has derived United Energy's 2008 base year opex from the actual costs incurred by JAM in 2008, the non-recurrent costs identified by the WOBCA are equally applicable to United Energy.

To determine the actual dollar amount of JAM’s non-recurrent costs allocated to United Energy, the AER considered the total costs incurred by JAM during the 2008 calendar year. In particular, the AER has had regard to independent submissions from both Jemena and United Energy that disaggregated the total costs incurred by JAM into a range of cost categories.[73] Excluding rounding differences, the total amounts of the individual costs categories identified by Jemena and United Energy were almost identical, with the exception of ‘other’ costs. Specifically, the total of other costs submitted by United Energy was [c-i-c] million (nominal), compared to [c-i-c] million (nominal) as submitted by Jemena.[74] The AER notes, however, that Jemena’s disaggregation of JAM’s costs was more detailed than that submitted by United Energy. Once the additional costs explicitly identified by Jemena (but not United Energy) were combined with Jemena’s ‘other’ costs, the summation was equal to United Energy’s total of [c-i-c] million (nominal).[75]

Importantly, the AER notes that the additional cost categories identified by Jemena reflect the non-recurrent costs proposed in its regulatory proposal. Given the comparability of these costs with United Energy’s ‘other’ costs category, the AER considers that the other cost category proposed by United Energy also reflects expenditure which is non-recurrent. Accordingly, the AER has excluded non-recurrent expenditure, totalling [c-i-c] million ($2010), from United Energy's base year level of

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67 Jemena, *Regulatory proposal, appendix 7.3, PriceWaterhouseCoopers: Independent review of whole of business cost allocation (confidential)*, November 2009, p. 8.

68 ibid., pp. 15–16.

69 ibid., pp. 15–16.

70 Jemena *Regulatory proposal*, p. 133.

71 ibid.

72 Jemena, *Regulatory proposal, appendix 7.3, PriceWaterhouseCoopers: Independent review of whole of business cost allocation (confidential)*, November 2009, p. 12.

73 Jemena, *Regulatory proposal, appendix 7.3, PriceWaterhouseCoopers: Independent review of whole of business cost allocation (confidential)*, November 2009, pp. 15–16; *Alinta Asset Management Pty Ltd ('AAM'), United Energy OSA – 2008 actual costs*, June 2009, p. 17.

74 ibid.

75 ibid.

opex. This expenditure reflects the percentage of JAM's non-recurrent expenditure allocated to United Energy.[76]

Changes in capitalisation policy
CitiPower and Powercor proposed to capitalise (that is, a transfer of opex to capex) more of its indirect overhead expenditure over the forthcoming regulatory control period.[77] The AER has accepted this increased amount of capitalisation. Accordingly, the AER has reduced CitiPower's and Powercor's base level of opex by $2.9 million ($2010) and $4 million ($2010) respectively.[78] The AER has correspondingly increased CitiPower's and Powercor's capex associated with indirect overheads (refer to chapter 8).

Change in base year costs between 2009 and 2010

The Victorian DNSPs have adopted 2009 as the base year (with the exception of United Energy) and escalated these costs for changes in scale and real costs. Jemena submitted that the base year costs should be inflated to the start of the forthcoming regulatory control period based on the ESCV's assumed opex efficiencies between 2009 and 2010.[79] CitiPower, Powercor and SP AusNet also proposed scale and real cost increases to escalate 2009 base year costs to establish forecast opex for the forthcoming regulatory control period. The AER's consideration of these proposals is detailed in sections 1.7.5 and 1.7.6.

The AER has rolled forward the 2009 base year costs to 2010 (the last year of the current regulatory control period) consistent with the approach proposed by Jemena, which is based on the change in costs assumed by the ESCV in determining the benchmark opex allowance for 2009 and 2010 in its 2006 EDPR. The roll forward of the actual 2009 base year costs takes into account the change in costs assumed by the ESCV in determining the 2009 and 2010 benchmark opex allowance. This is also consistent with the ESCV's approach of assuming that any cost efficiencies achieved by the Victorian DNSPs in the final year of the regulatory control period are zero.

AER conclusions

The AER has compared the Victorian DNSPs' proposed base opex and has adjusted these proposals to reflect the required amendments for the reasons identified above. These adjustments are provided in Table 7.1. In each case the Victorian DNSPs' 2009 opex is lower than their proposed base opex. Based on a consideration of the opex factors which includes:

- the information in the Victorian DNSPs' proposals
- analysis undertaken by the AER, the Victoria DNSPs' actual opex and expected opex preceding the 2011–15 regulatory control period
- benchmark operating expenditure that would be incurred by an efficient DNSP; and

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76 ibid.
77 Powercor, *Regulatory proposal*, p. 144
78 CitiPower/Powercor, *Cost escalation and forecast templates and data*, 31 March 2010, p. 15
79 Jemena, *Regulatory proposal*, p. 129

- as the DNSPs forecast opex is referrable to arrangements which in the opinion of the AER do not reflect arms length terms

the Victorian DNSPs' proposed base opex does not reasonably reflect:[80]

- the efficient costs that a prudent operator in the circumstances of the DNSPs would require to achieve the opex criteria including the opex objectives[81]

- does not reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives.[82]

In relation to United Energy which did not propose a base year amount of opex, the AER is also not satisfied for the reasons discussed above that the opex proposed reasonably reflects the efficient costs that a prudent operator in the circumstances of United Energy would require to achieve the opex criteria including the opex objectives or the realistic expectation of the input costs required to achieve the opex objectives.

For these reasons, the AER is not satisfied that the Victorian DNSPs' proposed base opex reasonably reflects the opex criteria. Instead, the AER has estimated the required base year opex for each DNSP, on the basis of and by making the minimum adjustments necessary as discussed in this chapter to their base opex proposals which it is satisfied reasonably reflects the opex criteria.

These AER's adjustments and the draft decision opex for each DNSP are set out in Table 7.9 and Table 7.10

[80] Clauses 6.5.6(e)(1)(3)(5)(9) of the NER
[81] Clause 6.5.6(c)(2) of the NER
[82] Clause 6.5.6(c)(3) of the NER

Table 7.9 AER conclusion on adjustments to 2009 base year ($’m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Reported/estimated base opex	36.8a	124.9[a]	47.2[b]	141.0[c]	91.2[d]
Movement in provisions	[c-i-c]	[c-i-c]	–	–	–
Distribution licence fees	–0.6	–0.8	–	–0.3	–
AMI reclassifications	–	–	–	–	–
GSL payments	–	–2.0	–	–5.5	–0.1
Avoided distribution costs	–	–	–	–	–
Allocation of overheads to base year	–	–	–	[c-i-c]	[c-i-c]
Exclusion of management fees	–	–	[c-i-c]	[c-i-c]	[c-i-c]
Exclusion of corporate strategy costs	–	–	[c-i-c]	–	[c-i-c]
Non-recurrent expenditure[e]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Change capitalisation of indirect overheads	–2.9	–4.1	–	–	–
2010 benchmark efficiency adjustment	0.6	4.1	1.5	3.6	–0.2
Draft decision base opex	**32.9**	**115.7**	**44.0**	**117.6**	**85.0**

(a) CitiPower, Powercor, *CitiPower ,Powercor response to AER's further information request on provision of unaudited 2009 regulatory accounts*, March 10 2010

(b) Jemena Regulatory Information Notice, 30 November 2009

(c) SP AusNet, *SP AusNet response to AER's further information request on provision of unaudited 2009 regulatory accounts*, March 24 2010, p.1-2

(d) Based on JAM's 2008 regulatory accounts and United Energy's estimated internal costs adjusted by the AER to reflect United Energy's current business model.

(e) Non-recurrent expenditure includes regulatory reset costs, whereas in chapter 13, non-recurrent costs do not include regulatory reset costs.

Table 7.10 Draft decision, base opex ($'m, 2010)

	CitiPower[a]	Powercor[a]	Jemena[b]	SP AusNet[c]	United Energy
DNSP proposed base opex	36.2	133.6	51.0	127.0	np
Draft decision base opex[d]	32.9	115.7	44.0	117.6	85.0

(a) CitiPower, *Regulatory proposal*, p. 148; Powercor, *Regulatory proposal*, p.144
(b) Jemena, *Regulatory proposal*, p.142
(c) SP AusNet, *Regulatory proposal*, p.205
(d) The difference between the DNSPs' proposed base opex and the AER's draft decision base opex will not correspond to the total adjustments in table 7.9 as the AER has adopted Citipower and Powercor's unaudited 2009 regulatory accounts, Jemena's estimated 2009 costs from its ECM model proposals and SP AusNet's extract of its unaudited 2009 regulatory accounts exclusive of updated non recurrent costs rather than their regulatory proposals.
np not provided.

7.5.5 Scale escalation

Scale escalation is typically expressed in terms of an annual rate of growth in opex resulting from an increase in the size of the distribution network. The annual growth rate is determined with reference to scale escalation or network growth drivers that are considered to approximate the resultant growth in the network and in-turn, opex. The annual growth rate is used to escalate base opex and is typically adjusted to reflect identified economies of scale. These savings accrue to the DNSP (and in turn customers) from doing 'more of the same' operating and maintenance activities.

This section presents an overview of the Victorian DNSPs' proposals and the AER's considerations and conclusions with respect to scale escalation. The AER's detailed assessment of the Victorian DNSPs' scale escalation proposals is discussed in appendix J.

As discussed in section 7.5.1, in deciding whether the Victorian DNSPs' forecast opex proposals reasonably reflect the opex criteria, the AER has, as relevant, had regard to the opex factors.

Part of the Victorian DNSPs' forecast opex proposals provided an allowance for scale escalation. Relevant to assessing and determining whether their proposed forecast opex allowance for scale escalation reasonably reflects the opex criteria are the following opex factors, which the AER has specifically had regard to:

- the actual and expected opex of the DNSP during the current and previous regulatory control periods.[83]

Section 6 of appendix J presents a comparison of actual opex incurred during these regulatory control periods against the Victorian DNSPs' proposed opex. The AER has taken into account this analysis, in particular the consideration of any observed trends in actual opex:

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83 Clause 6.5.6(e)(5) of the NER.

- the relative prices of operating and capital inputs.[84]

In analysing the trend in actual opex relative to the Victorian DNSPs' proposals, an adjustment was made to actual opex to minimise the impact of real input price changes on opex to ensure changes in actual opex could be attributable to changes in activity levels (which is of most relevance to scale escalation):

- the substitution possibilities between opex and capex.[85]

Section J.5.2 of appendix J discusses the substitution of opex and capex and where relevant, the AER has adjusted the Victorian DNSPs' proposed forecast opex allowance. Specifically, the AER examined the changes in the level of reliability quality maintained (RQM) capex and estimated the impact this would have on a DNSP's forecast opex allowance.

In addition to the specific opex factors noted above, the AER notes that a forecast opex allowance inclusive of scale escalation is consistent with a forecast opex allowance that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[86] The inclusion of amounts for scale escalation ensures that the total forecast opex allowance incorporates the incremental efficient cost of servicing a growing network over the forthcoming regulatory control period.

Each of the Victorian DNSPs, with the exception of United Energy, applied an explicit escalation to its base opex proposal for growth in the size of the distribution network.

The DNSPs proposed the following growth rates, adjustments to those rates and scale opex increases for the forthcoming regulatory control period are provided in Table 7.11.

84 Clause 6.5.6(e)(6) of the NER.
85 Clause 6.5.6(e)(7) of the NER
86 Clause 6.5.6(c)(3) of the NER.

Table 7.11 Victorian DNSP proposed growth rates and scale escalation opex (per cent, per annum)

	Gross growth rate	Economy of scale adjustment	Net growth rate[d]	Proposed scale opex ($'m, 2010)
CitiPower[a]	5.1	45.0	2.8	21.1
Powercor[a]	3.6	35.2	2.3	56.7
Jemena	–0.3	–	–0.3	–3.1
SP AusNet[b]	1.7	52.8	0.8	13.1
United Energy[c]	–	–	–	–

(a) 5.1 and 3.6 per cent calculated as the average annual rate of change in Network and PNS scale opex from 2010 to 2015, prior to any adjustment for economies of scale.

(b) 1.7 per cent calculated as the average annual rate of change in scale opex from 2010 to 2015. Based on 1.4 per cent average annual growth in SP AusNet customer numbers (used as a proxy for operating cost growth).

(c) United Energy has tendered its Operating Services Agreement (OSA) which is due to commence in 2011. It is United Energy's position (United Energy email to AER dated 29 March 2010) that 'bidders in responding to the tender exercise would have made their own assessment of these factors in developing their cost forecasts and pricing offers.' It is not clear from UED's regulatory proposal the extent to which UED's opex volume assumptions that formed the basis of the tender exercise include consideration of scale escalation. As a result, the remainder of this section refers to UED as not making an explicit scale escalation proposal.

(d) Net growth rate = Gross growth rate x (1 – economy of scale adjustment).

Source: AER analysis; CitiPower and Powercor's cost escalation models; Jemena forecast data model; SP AusNet opex growth model; United Energy, Regulatory proposal, 30 November 2009.

Submissions

The Energy Users Coalition of Victoria (EUCV) made specific reference to the DNSPs' scale escalation proposals, while submissions from the EUCV, Consumer Action Law Centre and Minister for Energy Resources (MER) addressed the issue of opex more generally.

The EUCV suggested that a closer examination of the impact the various growth drivers have on opex was required.[87] Specific reference was made to the use of consumption as a driver and the negligible impact on opex from existing customer consumption growth as opposed to the physical extension of the network.

> If the new customers extend the geographical area serviced, then it is likely that the increase will result in more opex. If, however, the increased number result from increasing density of customers (eg if a house is pulled down and replaced with units) then the increase in opex is marginal at most.[88]

[87] EUCV, p. 54.
[88] ibid., p. 55.

> If the increased demand is purely managed by increasing assets sizes in an existing network (especially if old undersized assets are replaced by larger but new assets) then the increase in demand has little impact on opex required.[89]

The EUCV also recognised that the level of renewal capex is likely to have an impact on operating and maintenance activity.

> With the increase in capex for refurbishment, there must be a proportionate reduction in opex, as this is what justifies the replacement of old assets with new assets.[90]

AER considerations

For the reasons discussed in appendix J, the AER has adopted two growth drivers for each DNSP:

- a composite network growth factor calculated as a simple average of the annual growth in line length and the number of distribution transformers and zone substations over the forthcoming regulatory control period
- the annual growth in customer numbers over the forthcoming regulatory control period.

In assessing each of the DNSPs' proposed growth drivers, the AER recognises that the growth drivers are used to escalate base year opex resulting from an increase in the physical size (that is, scale) of the distribution network. The cost drivers for geographic monopolies that operate within an interconnected network and provide a relatively homogenous service should also be similar.

The Victorian DNSPs' proposals do not reflect the physical homogeneity and interconnectivity of the network. The DNSPs proposed ten different growth drivers,[91] resulting in growth rates from –1.6 per cent per annum to +5.2 per cent per annum (see section J.5.1 of appendix J). However, the growth in the actual physical network required to be maintained and the customers a DNSP is required to service is relatively similar across the DNSPs.[92]

The AER considers that growth factors based on physical metrics such as line length and the number of distribution transformers and zone substations[93] results in forecasts of opex that most closely reflect the actual growth in operating and maintenance activity levels and are more likely to reasonably reflect the opex criteria in clause 6.5.6(c) of the NER.

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89 ibid., p. 56.
90 ibid., p. 49.
91 Network replacement cost, Full Time Equivalent working hours, customer numbers, peak demand, energy consumption, lagged customer numbers, line length, lagged line length overhead, lagged line length underground and zone substations.
92 See table J.6 of appendix J.
93 Growth in the number of zone substations was proposed by SP AusNet and adopted by the AER for the draft decision. The AER will consider alternatives such as growth in installed zone substation capacity in response to the draft decision where such alternatives are sufficiently documented and substantiated.

The AER unadjusted growth rates are outlined Table 7.12

Table 7.12 AER variation to Victorian DNSP proposed gross growth rates (per cent, per annum)

	DNSP proposed gross growth rates	AER variation	AER gross growth rates[a]
CitiPower	5.1	–4.1	1.0
Powercor	3.6	–2.2	1.4
Jemena	–0.3	1.4	1.1
SP AusNet	1.7	–0.2	1.5
United Energy	–	–	1.0

(a) Average annual growth rate applying the AER growth drivers.
Source: AER analysis.

The AER adjusted the gross growth rates (Table 7.12 above) for economies of scale and the effects of the capex/opex trade-off.

The AER adjustments to the gross growth rates are presented in Table 7.13 and the final net growth rates and scale opex allowances are presented in Table 7.14 below.

For further discussion on the assessment of the DNSP proposals and the basis for the conclusions made by the AER, refer to appendix J.

Table 7.13 AER conclusion on net growth rates (per cent, per annum)

	Gross growth rate	Economy of scale	Capex/opex trade-off[b]	Net growth rate
CitiPower	1.0	–0.5[a]	–0.2	0.3
Powercor	1.4	–0.8	–0.1	0.5
Jemena	1.1	–0.6	–0.1	0.4
SP AusNet	1.5	–0.9	–0.1	0.5
United Energy[c]	1.0	–0.5	–0.0	0.4

(a) AER's conclusion on economies of scale (53.3 per cent) expressed as a growth rate per annum. The actual variation for CitiPower is 8.2 per cent (see appendix J) converts to –0.1 per cent based upon the AER's gross growth rate of 1.0 per cent. This applies to the remaining DNSPs.
(b) Average annual growth rate reflective of the variations presented in appendix J.
(c) May not add due to rounding.

Table 7.14 AER scale escalation growth rates and scale opex allowance ($’m, 2010)

	Net growth rate (per cent, per annum)	2011 ($'m)	2012 ($'m)	2013 ($'m)	2014 ($'m)	2015 ($'m)	Total ($'m)
CitiPower	0.3	0.1	0.2	0.3	0.4	0.5	**1.4**
Powercor	0.5	0.6	1.2	1.8	2.3	2.9	**8.8**
Jemena	0.4	0.2	0.3	0.5	0.7	0.8	**2.5**
SP AusNet	0.5	0.6	1.1	1.7	2.2	2.8	**8.4**
United Energy	0.4	0.3	0.6	0.9	1.2	1.5	**4.6**

Source: AER analysis.

AER conclusions

For the reasons discussed above, and in appendix J, the AER is not satisfied that the Victorian DNSPs’ opex proposals reasonably reflect the opex criteria, including the opex objectives.

The AER considers the Victorian DNSPs’ opex proposals should be adjusted for the impact of the growth drivers based on physical metrics, economies of scale and the capex/opex trade-off by the amounts in Table 7.13 and Table 7.14. The AER considers that these amounts reflect the minimum adjustment necessary in order for the AER to be satisfied that the Victorian DNSPs' opex and capex allowances reasonably reflect the opex criteria. In coming to this view, the AER has had regard to the opex factors.

7.5.6 Real cost escalation

Each of the Victorian DNSPs applied real cost escalation to their opex proposals for forecast increases in labour and materials different to forecast increases in the consumer price index. The AER's detailed consideration of labour and materials cost escalation is discussed in appendix K.

As discussed in section 7.5.1, in deciding whether the Victorian DNSPs' forecast opex proposals reasonably reflect the opex criteria, the AER has, as relevant, had regard to the opex factors.

Part of the Victorian DNSPs’ forecast opex proposals provided an allowance for real cost escalation. In assessing and determining whether the Victorian DNSPs' proposed forecast opex allowance for real cost escalation reasonably reflects the opex criteria the AER has had specific regard to the following opex factor:

- the relative prices of operating and capital inputs.[94]

This section (further supported by appendix K), presents the Victorian DNSPs' proposals and the AER's considerations and conclusions about real cost escalation. The AER considers it appropriate to include, within the forecast opex allowance, an

[94] Clause 6.5.6(e)(6) of the NER.

amount for increases in labour and material input costs where the net impact of these costs are forecast to increase above the consumer price index. The AER has taken into account this analysis, in particular the consideration of the relative prices of operating and capital inputs.

In addition to the specific opex factor noted above, the AER notes that a forecast opex allowance inclusive of real cost escalation is consistent with a forecast opex allowance that reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.[95] The inclusion of amounts reflective of real input prices ensures a DNSPs' efficient forecast opex allowance is maintained in real terms over the forthcoming regulatory control period.

The Victorian DNSPs' opex proposals attributable to real cost escalation are outlined in appendix K.

Table 7.15 DNSP proposed opex real cost increases ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	2.0	2.8	3.9	4.5	5.3	**18.6**
Powercor	8.1	11.5	15.5	19.6	23.5	**78.2**
Jemena	3.0	4.2	5.7	7.1	8.3	**28.1**
SP AusNet	2.3	4.8	7.5	10.1	12.5	**37.3**
United Energy	0.4	0.9	1.3	1.8	2.2	**6.6**

Source: CitiPower, *Regulatory proposal*, p. 148; Powercor, *Regulatory proposal*, p. 144; Jemena, response to information requested on 16 February 2010, confidential, submitted on 25 February 2010; SP AusNet, response to information requested on 16 February 2010, confidential, submitted on 26 February 2010; United Energy, response to information requested on 10 May 2010, confidential, submitted on 14 May 2010

AER considerations

For the reasons discussed in appendix K, the AER considers that the weighted opex escalation rates outlined in table 7.16 reasonably reflect the impact of the movement in labour and materials prices in the forthcoming regulatory control period.

95 Clause 6.5.6(c)(3) of the NER.

Table 7.16 Weighted opex escalation rates (per cent)

	2011	2012	2013	2014	2015
CitiPower	2.1	3.2	4.5	6.1	6.9
Powercor	2.2	3.3	4.6	6.5	7.3
Jemena	2.0	3.1	4.2	5.5	6.6
SP AusNet	1.4	2.2	3.1	4.4	5.2
United Energy	1.9	2.8	4.0	5.5	6.3

Source: AER analysis; CitiPower, response to information requested on 10 May 2010, confidential, submitted on 13 May 2010; Powercor, response to information requested on 10 May 2010, confidential, submitted on 13 May 2010; Jemena, response to information requested on 10 May 2010, confidential, submitted on 15 May 2010; SP AusNet, response to information requested on 10 May 2010, confidential, submitted on 17 May 2010.

The AER applied these escalation rates to the base opex, escalated for the impact of forecast scale increases, for each of the Victorian DNSPs, as shown in table 7.17.

The AER notes that the impact of real cost increases, as calculated in table 7.17, is lower than that proposed by the Victorian DNSPs. One reason for this is that the AER does not consider the labour cost escalators proposed by the Victorian DNSPs reasonably reflect the opex criteria, as discussed in appendix K. The AER's consideration of the Victorian DNSPs' base year opex, and escalation of the base year opex for the forecast impacts of scale increases, discussed in sections 7.5.4 and 7.5.5 respectively, has also impacted the real cost increases in table 7.17.

AER conclusions

For the reasons discussed above, and in appendix K, the AER is not satisfied that the Victorian DNSPs’ opex proposals reasonably reflect the opex criteria, including the capex and opex objectives.

Table 7.17 AER conclusion on opex real cost increases ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	0.7	1.1	1.5	2.0	2.3	**7.6**
Powercor	2.5	3.8	5.4	7.6	8.7	**28.1**
Jemena	0.9	1.4	1.8	2.5	2.9	**9.5**
SP AusNet	1.7	2.7	3.7	5.2	6.2	**19.5**
United Energy	1.6	2.4	3.4	4.7	5.5	**17.6**

Source: AER analysis

The AER considers that the Victorian DNSPs’ opex proposals should be adjusted for the impact of labour and materials real cost escalation by the amounts in table 7.17. The AER considers that these amounts reflect the minimum adjustment necessary in order for the AER to be satisfied that the Victorian DNSPs' opex allowances reasonably reflect the opex criteria. In coming to this view, the AER has had regard to the opex factors.

7.5.7 Step changes

Having determined the base level of opex (section 7.5.4), the AER's approach is to recognise that DNSPs may be subject to changes in regulatory obligations or a change in operating environment that would not necessarily be reflected in the recurrent expenditure. The base opex should therefore be adjusted for costs arising from new (or changed) legislative obligations or a change in operating environment (termed ‘step changes’).

This section presents an overview of the Victorian DNSPs' proposals and the AER's considerations and conclusions with respect to step changes. The AER’s detailed assessment of the Victorian DNSPs' step change proposals is discussed in appendix L.

As discussed in section 7.5.1, in deciding whether the Victorian DNSPs' forecast opex proposals reasonably reflect the opex criteria, the AER has, as relevant, had regard to the opex factors.

The Victorian DNSPs’ forecast opex proposals included an allowance for step changes. Relevant to assessing and determining whether their proposed forecast opex allowance for step changes reasonably reflects the opex criteria, including the opex objectives, are the following opex factors, which the AER has specifically had regard to:

- benchmark opex that would be incurred by an efficient DNSP over the regulatory control period[96]
- the actual and expected opex of the DNSP during any preceding regulatory control periods[97]
- the substitution possibilities between opex and capex.[98]

In relation to each of these opex factors, respectively, the AER has specifically considered:

- The proposed step changes common across the DNSPs and the step changes that not every Victorian DNSP has proposed. Comparison of the DNSPs' forecast costs in the context of the future regulatory and operating environment as it affects each DNSP has been relevant to the AER's assessment.
- The step changes proposed by the Victorian DNSPs relating to incremental changes to the current regulatory obligations and operating environment where costs are being incurred, or should be, for current obligations and operations. Consideration of the level of existing costs, whether these costs are allowed for in

96 Clause 6.5.6(e)(4) of the NER.
97 Clause 6.5.6(e)(5) of the NER.
98 Clause 6.5.6(e)(7) of the NER.

the DNSPs' base operating and maintenance expenditure, and the impact on future costs given changes to the current regulatory obligations and operating environment have been relevant to the AER's assessment.

- The step changes proposed by the Victorian DNSPs relating to the age and condition of assets and forecast changes in capital expenditure that may give rise to changes in future opex. The relationship between the DNSPs' capex and opex programs and the justification for changes in opex given incentive arrangements and current operating and maintenance practices have been relevant to the AER's assessment.

In addition to the specific opex factors noted above, the AER considers that a forecast opex allowance inclusive of step changes is consistent with a forecast opex allowance that reasonably reflects the costs of a prudent operator in the circumstances of the relevant DNSP and enables the DNSP to comply with all applicable regulatory obligations or requirements.[99]

The Victorian DNSPs proposed a number of step changes as part of their regulatory proposals. In assessing these proposals, the AER has, in the first instance, had regard to changes in the regulatory obligations and subsequently changes in the operating environment. Consistent with the AER's approach to step changes in the NSW final electricity distribution determination, the AER has then assessed whether the proposed (operating expenditure) opex is prudent and efficient.[100]

The Victorian DNSPs' proposals are detailed in table 7.18.

[99] Clauses 6.5.6(c)(2) and 6.5.6(a)(2) of the NER

[100] AER, Final decision, New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, pp. 163–168.

Table 7.18 Victorian DNSP proposed opex step changes ($'m, 2010)

Step changes	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
Electricity safety regulation related	1.4	18.6	10.0	10.0	4.4	44.3
Environmental obligations	–	–	2.1	–	0.2	2.3
NGERS reporting	–	–	–	–	0.2	0.3
Climate change	1.9	13.6	6.6	18.3	6.9	47.3
Insurance	7.0	27.5	–	16.7	3.5	54.7
National framework for distribution network planning & expansion	2.7	4.3	0.8	1.9	1.8	11.5
Customer communications	0.4	1.0	4.4	3.9	4.3	14.0
Steady state related	–	–	0.6	5.4	1.0	7.0
Regulatory submission costs	–	–	3.4	–	–	3.4
Crime stopper licence fees	–	–	–	–	0.1	0.1
Earth testing non-CMEN areas	–	–	0.6	–	2.5	3.1
DNSP specific[a]	9.9	22.1	24.3	35.1	13.3	104.7
Total	**23.3**	**86.9**	**52.9**	**91.2**	**38.2**	**292.6**

Note: The AER notes that its analysis of the proposed opex step changes starts with values sourced from the Victorian DNSPs' November 2009 regulatory proposal. However, the AER has converted Jemena's and SP AusNet's regulatory proposals from $2009 to $2010. The AER further notes that the opex step changes in SP AusNet's regulatory proposal included a year of labour cost escalation to convert them from $2009 to $2010, and that the step change values quoted in the values listed in this table do not include this labour cost escalation. The AER also acknowledges that a number of DNSPs revised their regulatory proposals and that these values were subsequently updated. Where revised values were provided to the AER, these values have been noted and have been considered in the AER's assessment.
Totals may not add due to rounding.

(a) For SP AusNet this includes an overhead allocation issue, which is discussed in chapter 6.

Source: CitiPower, *Regulatory proposal*, 30 November 2009; Powercor, *Regulatory proposal*, 30 November 2009; Jemena, *Appendix 10: Capital and operational work plan 2010–15* (Confidential), 30 November 2009; SP AusNet, *Regulatory proposal*, 30 November 2009; United Energy, *Appendix B-7: Increased operating and maintenance costs*, 30 November 2009.

Submissions

The AER received a number of submissions on step changes, including from the:

- Energy Users Coalition of Victoria (EUCV)
- Victorian Employers Chamber of Commerce and Industry (VECCI).

The scope of these submissions, and how the AER has taken these submissions into account as part of its determinations, is discussed in appendix L.

AER conclusions

For the reasons discussed in appendix L, the AER is not satisfied that the Victorian DNSPs' opex step change proposals reasonably reflect the opex criteria, including the opex objectives. In coming to its view, the AER has had regard to the opex factors.

The AER has allowed expenditure for some step changes, including where costs have been imposed on the DNSPs to comply with obligations in relation to electrical safety, customer communications and compliance with the national framework for distribution network planning and expansion. The AER has not approved expenditure for step changes where the DNSP's proposal does not reasonably reflect the opex criteria, including that the expenditure is prudent and efficient. Specifically, each proposal should identify new or changed obligations and changes in the operating environment and appropriately quantify all cost savings and benefits.

The AER has also allowed a significant increase in insurance costs for SP AusNet and United Energy.

The AER considers the Victorian DNSPs' opex proposals should be adjusted to reflect the amounts in table 7.19.

Table 7.19 AER conclusion on the Victorian DNSP proposed opex step changes ($'m, 2010)

Step changes	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
Electricity safety regulation related	1.2	–17.1	0.9	5.3	1.4	–8.2
Insurance premiums	–	–	–	15.0	3.5	18.5
National framework for distribution network planning & expansion	2.7	4.3	0.5	1.9	1.4	10.8
Customer communications	0.3	0.7	2.5	–	2.3	5.9
Regulatory submission costs	1.7	4.0	3.5	–	2.2	11.4
DNSP specific	–	–	3.2	2.8	–	6.0
Total	**6.0**	**–8.1**	**10.7**	**25.0**	**10.9**	**44.5**

Note: Totals may not add due to rounding.

The AER considers that the amounts in table 7.19 reflect the minimum adjustment necessary in order for the AER to be satisfied that the Victorian DNSPs' opex step change allowances reasonably reflect the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

7.5.8 Self Insurance

Events for which the DNSP may be granted a self insurance allowance are those where the DNSP bears the risk of an event. The occurrence of such events (and potentially, their cost) cannot be accurately forecast. Self insurance may also be necessary if insurance is not available or only available on uneconomic terms or conditions. In some instances, self insurance is sought in addition to purchased insurance. Some DNSPs seek to self insure for the excess amount (deductibles), which is the amount DNSPs are liable to pay if they make a claim with their insurer. It is important to note that self insurance should only be for risks that are not otherwise remunerated through other components of the total revenue building blocks.

This section presents an overview of the Victorian DNSPs' proposals and the AER's considerations and conclusions with respect to self insurance. The AER’s detailed assessment of the DNSPs' self insurance proposals is discussed in appendix M.

As discussed in section 7.5.1, in deciding whether the Victorian DNSPs' forecast opex proposals reasonably reflect the opex criteria, the AER has, as relevant, had regard to the opex factors.

Part of the Victorian DNSPs’ forecast opex proposals provided an allowance for self insurance. Relevant to assessing and determining whether their proposed forecast opex allowance for self insurance reasonably reflects the opex criteria is the following opex factor, which the AER has specifically had regard to:

- the actual and expected opex of the DNSP during the current regulatory control periods.[101]

In assessing the Victorian DNSPs' self insurance proposals, the AER reviewed whether the forecast opex allowance was already included within the DNSPs' base year actual expenditure (see appendix M). The AER determined that for self insurance proposals relating to below deductible expenditure**,** certain proposals were not accepted on the basis that to allow such expenditure would double count the efficient level of below deductible costs in the base year opex allowance (see appendix M).

In addition to the opex factors, the AER considers that a forecast opex allowance inclusive of self insurance is consistent with a forecast opex allowance which achieves the opex objective regarding maintaining the reliability, safety and security of the distribution system through the supply of standard control services.[102]

The Victorian DNSPs each included an allowance for self insurance within their opex forecast for the forthcoming regulatory control period. Jemena, SP AusNet and United Energy each provided a board resolution to self insure the risks identified in their regulatory proposal.[103] CitiPower, Powercor, SP AusNet and United Energy engaged Aon Global Risk Consulting (Aon) and Jemena engaged Marsh Pty Ltd (Marsh) to quantify their current and future potential self insured risks.[104]

The Victorian DNSPs' opex proposals attributable to self insurance are outlined in tables 7.20 to 7.24 below and discussed in detail in appendix M.

Submissions

In commenting on the AER's position in the ETSA Utilities draft decision, the EUCV stated that:

> In its detailed assessment of increases in opex for self insurance, the AER took a firm line in its review of the ETSA Utilities claims for increased costs.[105]

The EUCV considered that the AER should take a similar approach in assessing the Victorian DNSPs' regulatory proposals.[106]

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101 Clause 6.5.6(e)(5) of the NER.

102 Clause 6.5.6(a)(4) of the NER.

103 CitiPower and Powercor stated that they did not have a board resolution to self insure but did provide board minutes relating to the establishment of their Discretionary Risk Management Scheme (DRMS) with CHED Services which encompasses self insurance arrangements and of which CitiPower and Powercor are members. CitiPower and Powercor also provided the AER with the Constitution under which the DRMS was established, proof of membership of the DMRS and a document setting out the policy framework of the DRMS.

104 Aon Corporation provides risk management services, insurance and reinsurance brokerage, and human capital consulting, globally. See Aon website http://www.aon.com.au/australia/site-map.jsp; Marsh Pty Ltd provides risk and insurance services. See Marsh website http://www.marsh.com.au/about_Marsh/index.php.

105 Energy Users Coalition of Victoria, *Victorian Electricity Distribution Revenue Reset - a response* February 2010, p. 60.

106 Energy Users Coalition of Victoria, *submission to the AER*, p. 60.

AER considerations

The AER has assessed the Victorian DNSPs' self insurance proposals for the 2011–15 regulatory control period against the following criteria:

- whether or not the event is already compensated for through any other aspect of the regulatory regime, including through:
  - other components of the opex forecast (for example, through recurrent expenditure that is incurred during the base year)
  - the capex forecast or roll-forward of the RAB at the end of the regulatory control period
  - the weighted average cost of capital (WACC)
  - pass through events
- whether any remaining negative risks (not already compensated) are outweighed by upside risks (that is, risks are negatively asymmetric in aggregate).

The AER has also introduced broader compliance and monitoring requirements as part of this distribution determination (see chapter 21) which will mandate certain reporting requirements throughout the regulatory control period. The AER's requirements pertaining to self insurance are included in this new reporting regime.

AER conclusion

For the reasons discussed in appendix M, the AER is not satisfied that the Victorian DNSPs' self insurance opex proposals reasonably reflect the opex criteria, including the capex and opex objectives.

The AER considers the Victorian DNSPs' self insurance opex proposals should be adjusted to reflect the amounts in tables 7.20 to 7.24.

Table 7.20 CitiPower's self insurance allowances for 2011–15 regulatory control period ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability	2.72	–
Motor vehicle	0.32	–
Property	1.82	–
Total	**4.86**	**–**

Table 7.21 Powercor's self insurance allowances for 2011–15 regulatory control period ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability	12.18	–
Motor vehicle	1.70	–
Property	2.33	–
Total	**16.21**	**–**

Table 7.22 Jemena's self insurance allowances for 2011–15 regulatory control period ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Substations—catastrophic or component failure	1.028	–
Other assets—storms and lightning	0.552	–
Other assets—pole fires	0.036	–
Damage to third party property	0.167	0.167
Public liability—fatality	0.051	0.051
Public liability—injury	0.304	0.304
Total	**2.669**	**0.522**[a]

(a) An allowance of $104 300 per year of the regulatory period.

Table 7.23 SP AusNet's self insurance allowances for 2011–15 regulatory control period ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability—general	8.022	–
Bushfire	3.558	–
Poles and wires	9.100	–
Insurer default	0.157	–
Fraud	0.044	–
Total	**20.881**	–

Table 7.24 United Energy's self insurance allowances for 2011–15 regulatory control period ($'m, 2010)

Risk	Regulatory proposal	AER draft determination
Liability —general	0.535	–
Liability—fire	0.245	–
Liability—asbestos	0.120	0.12
Poles and wires	2.710	–
Fraud	0.015	–
Insurer's default	0.125	–
Property	13.750	–
Contaminated land	2.380	–
Environmental	0.220	–
Total	**20.030**	**0.12**[a]

(a) An allowance of $24 000 per year of the regulatory period.

The AER considers that the amounts reflected in tables 7.20 to 7.24 reflect the minimum adjustment necessary in order for the AER to be satisfied that the Victorian DNSPs' self insurance opex allowances reasonably reflect the opex criteria. In coming to this view, the AER has had regard to the opex factors.

7.5.9 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 are a legitimate expense for which a DNSP should be provided an allowance.[107]

Part of the Victorian DNSPs’ forecast opex proposals provided an allowance for debt raising costs. Relevant to assessing and determining whether a DNSPs' proposed forecast opex allowance for debt raising costs reasonably reflects the opex criteria are the opex factors, and for debt raising costs the AER has specifically had regard to:

- benchmark opex that would be incurred by an efficient DNSP over the regulatory control period.[108]

[107] 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.

[108] Clause 6.5.6(e)(4) of the NER.

The AER has jointly assessed the benchmark debt raising costs of the Victorian DNSPs on this basis. Where consultant reports have been submitted by one of the DNSPs, to the extent that the information is pertinent to all Victorian DNSPs, the information has been jointly considered within this section.

Direct debt raising costs

The Victorian DNSPs' proposed debt raising costs as a component of their opex forecasts. The direct debt raising costs proposed by the DNSPs, to be applied to the benchmark proportion of the regulatory asset base (RAB) that is financed by debt, are outlined in table 7.25.

Table 7.25 Victorian DNSP proposed direct debt raising costs (basis points, per annum)

CitiPower	Powercor	Jemena	SP AusNet	United Energy
12.3	12.3[a]	12.0	12.0	11.8

(a) Powercor, in their regulatory proposal, proposed direct debt raising costs of 12 basis points per annum. However in their supporting documentation Powercor proposed direct debt raising costs of 12.3 basis points per annum. The AER believes this error is due to rounding.

Source: CitiPower, *Regulatory proposal*, p. 173, Powercor, *Regulatory proposal*, p. 169, Jemena, *Regulatory proposal*, p. 141, SP AusNet, *Regulatory proposal*, p. 231, United Energy, *Regulatory proposal*, p. 149.

In determining their respective direct debt raising costs, CitiPower, Powercor, SP AusNet and United Energy have all drawn on an expert opinion report on debt and equity raising costs prepared by the Competition Economists Group (CEG) for ETSA Utilities as part of the ETSA Utilities Regulatory Proposal 2010–15.[109] In support of the CEG report, CitiPower and Powercor have also provided a letter prepared by CEG (CEG letter) which provided an update of the CEG report by incorporating new data and utilising a prescribed discount rate for amortisation.[110]

Jemena's proposal on debt raising costs noted that they would be consistent with a benchmark efficient firm.[111] Jemena did not refer to any third party consultation in determining its direct debt raising costs.

AER considerations

The AER's detailed analysis and consideration of the Victorian DNSPs' proposed direct debt raising costs are set out in appendix P. In summary, the AER considers that:

- the main arguments put forward by the Victorian DNSPs, including the basis of the CEG report and other reports, have been previously considered by the AER in the South Australian draft and final electricity distribution determinations

[109] CEG, *Debt and equity raising costs: A report for ETSA*, June 2009.
[110] CEG, Letter to Mark De Villiers, Manager Financial and Regulatory Strategy, CitiPower and Powercor, *Update to June 2009 Report: Debt and Equity Raising Costs*, 20 November 2009.
[111] Jemena, *Regulatory Proposal 2011-15*, 30 November 2009, p. 141.

- the outcome of this analysis was an update of the selection of bonds as well as some refinements to the Allen Consulting Group (ACG) methodology.

The AER will continue to apply its current approach based on the 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 underwriter league and volume (LEAG) tables 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 medium term note (MTN) issue size with the latest available data.

The direct debt raising cost allowance for the Victorian DNSPs is dependent on the number of standard sized debt issues required (based on the debt value of its RAB), and the nominal vanilla WACC applying to the draft decision (to be incorporated in the amortisation calculation).

Table 7.26 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 9.68 per cent.

Table 7.26 Draft decision direct debt raising costs with a nominal vanilla WACC of 9.68 per cent (basis points)

Fee	Explanation	1 issue	2 issues	4 issues	6 issues	10 issues
Amount raised ($'m, nominal)	Multiples of median MTN ($250)	250	500	1000	1500	2500
Gross under-writing fee	Median gross underwriting spread, upfront per issue	7.22	7.22	7.22	7.22	7.22
Legal and roadshow	$115k upfront per issue	0.74	0.74	0.74	0.74	0.74
Company credit rating	$50k per annum	2.00	1.00	0.50	0.33	0.20
Issue credit rating	4 basis points up front per issue	0.64	0.64	0.64	0.64	0.64
Registry fees	$3.5k up front per issue	0.14	0.14	0.14	0.14	0.14
Paying fees	$4/$1 million per annum	0.04	0.04	0.04	0.04	0.04
Total	**Basis points per annum**	**10.8**	**9.8**	**9.3**	**9.1**	**9.0**

The completion method

In addition to direct debt raising costs, CitiPower, Powercor and SP AusNet proposed early debt refinancing costs of 16.6 basis points per annum to refinance their debt three-to-six months prior to the date it was required.[112] This early debt refinancing cost approach was first submitted by ETSA Utilities in its regulatory proposal for the South Australian draft electricity distribution determination and was referred to as the 'completion method'. For convenience, any reference to this early debt refinancing cost approach here will be referred to as the completion method.

In support of the completion method, CitiPower, Powercor and SP AusNet provided an article from Standard and Poor's on refinancing.[113] In further support of this article, CitiPower and Powercor also provided a letter from Standard and Poor's clarifying their position on debt refinancing.[114] CitiPower and Powercor, in their respective proposals, noted the Treasury Risk Management Policy of CHEDHA Group (the holding company for CitiPower and Powercor investments) which requires debt funding requirements to be in place six months prior to the requirement for funding.[115] In line with this, SP AusNet also provided confidential extracts from an internal Board meeting regarding the update of its Treasury Risk Policy to address the 'change in the philosophy of the agencies' in refinancing debt.[116]

Taking into account the early debt financing costs of CitiPower, Powercor and SP AusNet, the proposed debt raising costs for the Victorian DNSPs are set out in table 7.27

Table 7.27 Victorian DNSP forecast benchmark debt raising costs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	4.0	4.3	4.4	4.5	4.5	**21.6**
Powercor	6.4	6.4	6.7	7.0	7.0	**33.5**
Jemena	0.5	0.6	0.6	0.7	0.7	**3.1**
SP AusNet	3.5	3.7	4.0	4.3	4.6	**20.0**
United Energy	1.0	1.1	1.1	1.2	1.2	**5.6**

Source: CitiPower, *Regulatory proposal*, p. 174, Powercor, *Regulatory proposal*, p. 170, Jemena, *Regulatory proposal*, p. 142, SP AusNet, *Regulatory proposal*, p. 234,

112 CitiPower, *Regulatory Proposal 2011 to 2015*, 30 November 2009 p. 173, Powercor, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 170 and SP AusNet, *Electricity Distribution Price Review, Regulatory Proposal*, November 2009 p. 232.

113 Standard and Poor's, *Ratings Direct: Refinancing And Liquidity Risks Remain, But Australia's Rated Corporates Are Set To Clear The Debt Logjam*, 22 April 2008.

114 Standard and Poor's, Letter to Julie Williams, Chief Financial Officer, CitiPower and Powercor, *Re: Liquidity Risk Management Request for Clarification*, 30 October 2009.

115 Cheung Kong Infrastructure Ltd and Hong Kong Electric Holdings Ltd Electricity Distribution Holdings (Australia) Pty Ltd; CitiPower, *Regulatory proposal*, p. 173 and Powercor, *Regulatory proposal*, p. 170.

116 SP AusNet, *Regulatory proposal*, p. 233.

United Energy, *Regulatory proposal*, p. 87. Note: Totals may not add due to rounding.

AER considerations

The AER's detailed analysis and considerations of CitiPower's, Powercor's and SP AusNet's proposed debt raising costs associated with the completion method are set out in appendix P. In summary, the AER considers that the benchmark firm should be compensated for the efficient costs of a refinancing plan. However, the AER does not consider that the allowance proposed by the Victorian DNSPs should be added to the (standard) direct debt raising costs allowance based on the ACG methodology. The AER considers that the allowance for (standard) direct debt raising costs already includes the efficient costs of a refinancing plan and that no increase in these costs is required.

AER conclusion

As a result of the AER's analysis of the Victorian DNSPs' regulatory proposals and additional information, the AER is not satisfied that the Victorian DNSPs' proposed debt raising cost allowances reasonably reflect the opex criteria, including the opex objectives.

The AER considers the debt raising allowances set out in table 7.28, and discussed below, represent the efficient costs that a prudent operator in the circumstances of the respective DNSPs would require to achieve the opex objectives. In coming to this view the AER has had regard to the opex factors.

Table 7.28 AER conclusion on benchmark debt raising costs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	0.70	0.73	0.76	0.79	0.81	**3.79**
Powercor	1.17	1.22	1.26	1.30	1.35	**6.30**
Jemena	0.43	0.43	0.44	0.45	0.46	**2.21**
SP AusNet	1.11	1.14	1.19	1.23	1.29	**5.96**
United Energy	0.75	0.78	0.80	0.81	0.82	**3.96**

CitiPower has an opening RAB of $1.29 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of CitiPower's opening RAB is around $771.9 million (nominal). Based on the refinements to the ACG methodology, CitiPower will require around 4 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.3 basis points per annum for direct debt raising costs is a reasonable benchmark for CitiPower. This benchmark is multiplied by the debt component of CitiPower's opening RAB to provide an average allowance of $0.76 million per annum ($2010).

Powercor has an opening RAB of $2.20 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of

Powercor’s opening RAB is around $1.32 billion (nominal). Based on the refinements to the ACG methodology, Powercor will require around 6 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.1 basis points per annum for direct debt raising costs is a reasonable benchmark for Powercor. This benchmark is multiplied by the debt component of Powercor's opening RAB to provide an average allowance of $1.26 million per annum ($2010).

Jemena has an opening RAB of $742 million (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of Jemena’s opening RAB is around $445 million (nominal). Based on the refinements to the ACG methodology, Jemena will require around 2 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.8 basis points per annum for direct debt raising costs is a reasonable benchmark for Jemena. This benchmark is multiplied by the debt component of Jemena's opening RAB to provide an average allowance of $0.44 million per annum ($2010).

SP AusNet has an opening RAB of $2.09 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of SP AusNet’s opening RAB is around $1.26 billion (nominal). Based on the refinements to the ACG methodology, SP AusNet will require around 6 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.1 basis points per annum for direct debt raising costs is a reasonable benchmark for SP AusNet. This benchmark is multiplied by the debt component of SP AusNet's opening RAB to provide an average allowance of $1.19 million per annum ($2010).

United Energy has an opening RAB of $1.39 billion (nominal). On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of United Energy’s opening RAB is around $833 million (nominal). Based on the refinements to the ACG methodology, United Energy will require around 4 bond issues over the forthcoming regulatory control period. As such, the AER considers that an allowance of 9.3 basis points per annum for direct debt raising costs is a reasonable benchmark for United Energy. This benchmark is multiplied by the debt component of United Energy's opening RAB to provide an average allowance of $0.79 million per annum ($2010).

7.6 AER conclusion

The AER has considered each of the Victorian DNSPs’ forecast opex proposals and for the reasons set out in this chapter, having had regard to the opex factors, is not satisfied that the forecasts reasonably reflect the opex criteria including the opex objectives. In summary, the AER is not satisfied that the expenditure associated with the Victorian DNSPs':

- proposed base year opex reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives[117]

[117] See section 7.5.4 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to the revealed cost approach, clause 6.5.6(e)(4) on the use of benchmarking and clause 6.5.6(e)(9) regarding related party contracts.

- application of real cost escalators reasonably reflects a realistic expectation of the cost inputs required to achieve the opex objectives[118]
- application of scale escalators reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives[119]
- proposed step changes are prudent or efficient[120]
- forecast self insurance program are prudent or efficient[121]
- proposed debt raising costs are prudent or efficient.[122]
- proposed DMIAs and GSL payments are prudent or efficient[123]

Under clauses 6.5.6(d) and 6.12.1(4) of the NER, the AER cannot accept a DNSP's total proposed forecast opex and set out an estimate of the required opex which it considers reasonably reflects the opex criteria.

After making the adjustments outlined in this chapter, the AER considers that a forecast opex allowance that reasonably reflects the opex criteria is $2 190 million ($2010) for the Victorian DNSPs. For each DNSP this equates to a forecast opex allowance of:

- CitiPower, $184 million ($2010)
- Powercor, $622 million ($2010)
- Jemena, $247 million ($2010)
- SP AusNet, $672 million ($2010)
- United Energy, $465 million ($2010).

These estimates of the required opex for each Victorian DNSP:

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118 See section 7.5.6 for a discussion of the opex factors, including clause 6.5.6(e)(6) in relation to the relative prices of operating and capital inputs.

119 See section 7.5.5 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to actual and expected opex, clause 6.5.6(e)(6) on the relative prices of operating and capital inputs and clause 6.5.6(e)(7) regarding the substitution between capex and opex.

120 See section 7.5.7 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to actual and expected opex and clause 6.5.6(e)(7) regarding the substitution between capex and opex.

121 See section 7.5.8 for a discussion of the opex factors, including clause 6.5.6(e)(5) in relation to actual and expected opex.

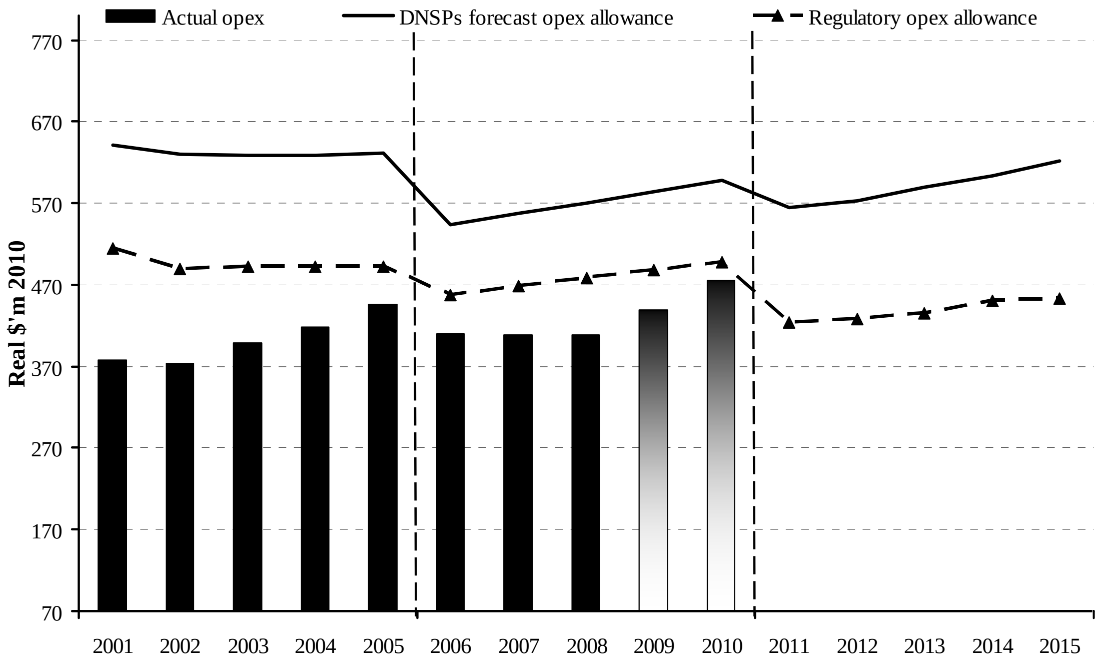
122 See section 7.5.9 for a discussion of the opex factors, including clause 6.5.6(e)(4) on the use of benchmarking.

123 See chapter 17 for a discussion on the DMIS. In reaching its conclusion about the DNSPs' proposed DMIAs, the AER has had regard to the extent to which the DNSP has considered, and made provision for, efficient non-network alternatives (clause 6.5.6(e)(10) of the NER). See chapter 15 for a discussion on GSLs.
See chapter 17 for a discussion of the opex factors relating to DMIS, including clause 6.5.6(e)(10) in relation to non-network alternatives.

- have been determined on the basis of the AER's assessment of the forecast opex proposals
- are the result of making the minimum adjustments necessary to the forecast opex proposals which the AER is satisfied reasonably reflect the opex criteria.

Figure 7.4 illustrates the AER’s draft decision for the Victorian DNSPs’ forecast opex allowance of $2 190 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.4 Victorian DNSP draft decision opex allowance



The DNSPs' actual opex is represented by the bars in Figure 7.4 above. The DNSPs' current underspend relative to the ESCV regulatory opex allowance is denoted by the difference between the bars and dashed line between 2001 and 2010. The Victorian DNSPs' underspend relative to their own proposals is denoted by the difference between the bars and the solid line between 2001 and 2010. The AER's draft decision opex allowance is denoted by the dotted line from 2011–15. The 2009 and 2010 bars represent the Victorian DNSPs' estimated opex as their audited actual opex are not yet available.

The AER draft decision opex allowance for the forthcoming regulatory control period is set at $2 190 million ($2010), which represents a reduction of $763 million, or 26 per cent below the Victorian DNSPs’ regulatory proposals (this broadly aligns with the DNSPs' expected underspend for the current regulatory control period).

An allowance of the $2 190 million ($2010) represents an increase of $49.0 million, or 2 per cent, above the Victorian DNSPs’ estimated actual opex in the current regulatory control period of $2 141 million.

Whilst the recommended expenditure outcomes can be seen as being consistent with the past performance of the DNSPs, the opex allowance is also consistent with the current and prospective Victorian regulatory environment over the forthcoming regulatory control period according to the AER’s assessment of associated cost drivers.

With the exception of the outcomes following the Victorian Bushfire Royal Commission (VBRC) (which subject to the requirements of clause 6.6.1 of the NER, may be treated as a pass-through event), the Victorian DNSPs will not be subject to numerous new regulatory or legislative obligations, or changes to their operating environments that have a material impact on expenditure over the forthcoming regulatory control period. This can be seen in section 7.5.7 where the AER has rejected many of the Victorian DNSPs' step change proposals ($293 million proposed, $44 million accepted) which included additional costs due to, among other things, climate change, insurance and regulatory matters. The AER has accepted that some new regulatory compliance costs will be borne by the DNSPs including in respect of electrical safety, network planning and customer communications.

The Victorian DNSPs have proposed service standards consistent with current levels, and as shown by advice from Nuttall Consulting, the impact of ageing assets is not considered to materially alter the existing opex profile necessary to maintain existing levels of service performance.

The distribution network will expand over the forthcoming regulatory control period, with the addition of new customers and assets. The AER has considered the impact on opex from growth (scale escalation) including expected productivity improvements and has allowed the value of the Victorian DNSPs’ opex allowance to be maintained in real terms (incorporating changes in real input costs for labour and materials). Further, while it is too early to evaluate the precise effect on efficiency from the use of advanced metering infrastructure (AMI – smart meters), the AER expects that such efficiencies will be evident over time and will impact on operating cost trends over time. Through its annual reporting framework, the AER will be monitoring the way AMI impacts on operating costs.

Therefore, the AER considers that a total opex allowance of $2.2 billion over the forthcoming regulatory control period, an increase of around 2 per cent on actual levels in the current regulatory control period, is justifiable. This compares to proposed increases sought by the Victorian DNSPs of around 38 per cent.

The Victorian DNSPs’ operate a mature and comparatively reliable network where asset performance and the operating environment are relatively stable, service performance is are being maintained, and aside from certain specified events (for example, outcomes from the VBRC) the AER has not observed a material change in the Victorian DNSPs' regulatory obligations. The result, under a revealed cost approach, is an efficient level of base expenditure consistent with audited actual costs and a path of opex that is expected to be relatively stable, with only modest increases from current levels. This level of expenditure is reflective of the continuity in regulatory outcomes and expectations. The decision, however, also incorporates continuing incentives for ongoing operating efficiency as well as maintenance and improvement in performance where this is valued by customers.

In accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept each of the Victorian DNSP's proposed forecast opex for the forthcoming regulatory control period. The AER is not satisfied that each of the Victorian DNSP's forecast opex, taking into account the opex factors, reasonably reflects the opex criteria in clause 6.5.6 of the NER. The AER has also set out its approach to opex in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

The AER's reasons are set out in section 7.5 of this draft decision.

The AER's estimate of each DNSP's required opex for the forthcoming regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out in Table 7.29 to Table 7.34 of this draft decision.

Table 7.29 AER draft decision opex allowance for 2011–15 ($'m, 2010)

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

(a) DMIS, GSL

Table 7.30 CitiPower draft decision opex allowance ($'m, 2010)

	2011	2012	2013	2014	2015	Total (2011–15)
CitiPower proposed opex	**45.4**	**47.3**	**50.6**	**49.1**	**51.5**	**244.0**
AER opex build-up						
AER base year costs	32.9	32.9	32.9	32.9	32.9	164.5
AER scale escalation	0.1	0.2	0.3	0.4	0.5	1.4
AER real cost escalation	0.7	1.1	1.5	2.0	2.3	7.6
AER step changes	1.2	0.7	0.9	1.6	1.5	6.0
AER debt raising costs	0.7	0.7	0.8	0.8	0.8	3.8
AER self insurance	–	–	–	–	–	–
AER other[a]	0.2	0.2	0.2	0.2	0.2	1.1
AER total opex	**35.8**	**35.8**	**36.6**	**37.9**	**38.2**	**184.4**
Adjustment	**–9.6**	**–11.5**	**–14.0**	**–11.1**	**–13.3**	**–59.6**
Adjustment (per cent)	**–21.2**	**–24.2**	**–27.7**	**–22.7**	**–25.8**	**–24.4**

(a) DMIS, GSL

Figure 7.5 illustrates the AER's draft decision for CitiPower's forecast opex allowance of $184 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.5 CitiPower draft decision opex allowance

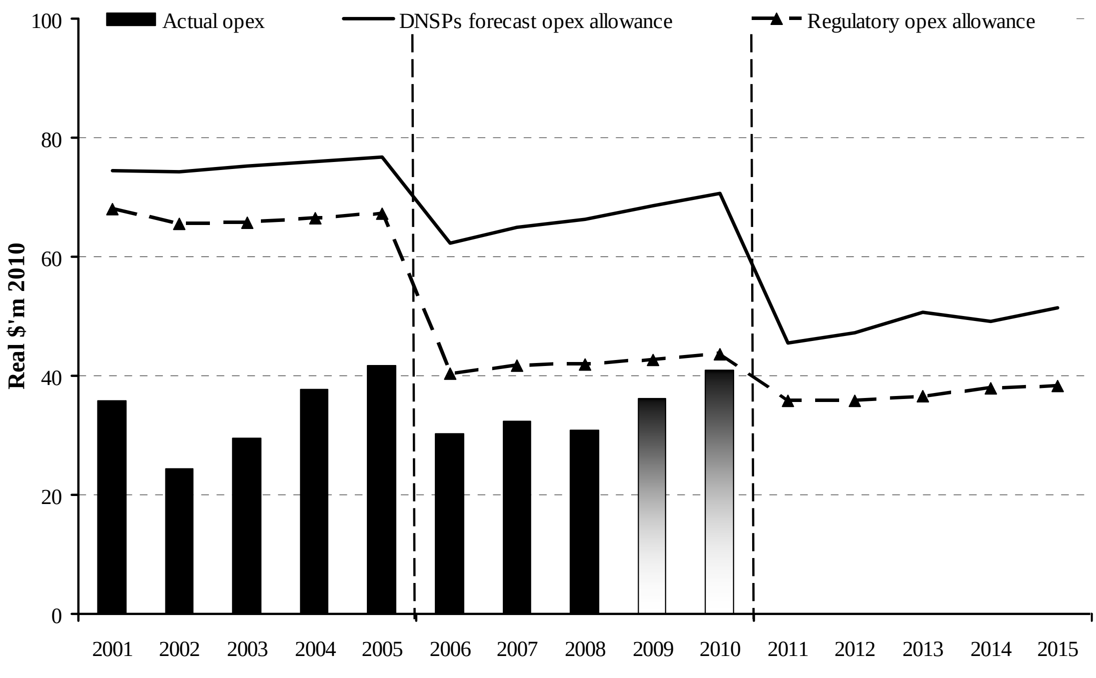


Table 7.31 Powercor draft decision opex allowance ($'m 2010)

	2011	2012	2013	2014	2015	Total (2011–15)
Powercor proposed opex	**165.0**	**171.3**	**178.7**	**187.3**	**199.9**	**902.2**
AER opex build-up						
AER base year costs	115.7	115.7	115.7	115.7	115.7	578.3
AER scale escalation	0.6	1.2	1.8	2.3	2.9	8.8
AER real cost escalation	2.5	3.8	5.4	7.6	8.7	28.1
AER step changes	–1.8	–2.5	–2.5	–0.5	–0.8	–8.1
AER debt raising costs	1.2	1.2	1.3	1.3	1.3	6.3
AER self insurance	–	–	–	–	–	–
AER other[a]	1.8	1.8	1.8	1.8	1.8	8.9
AER total opex	**119.9**	**121.2**	**123.3**	**128.2**	**129.6**	**622.3**
Adjustment	**–45.1**	**–50.1**	**–55.4**	**–59.0**	**–70.3**	**–280.0**
Adjustment (per cent)	**–27.3**	**–29.3**	**–31.0**	**–31.5**	**–35.2**	**–31.0**

(a) DMIS, GSL

Figure 7.6 illustrates the AER's draft decision for Powercor's forecast opex allowance of $622 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.6 Powercor draft decision opex allowance

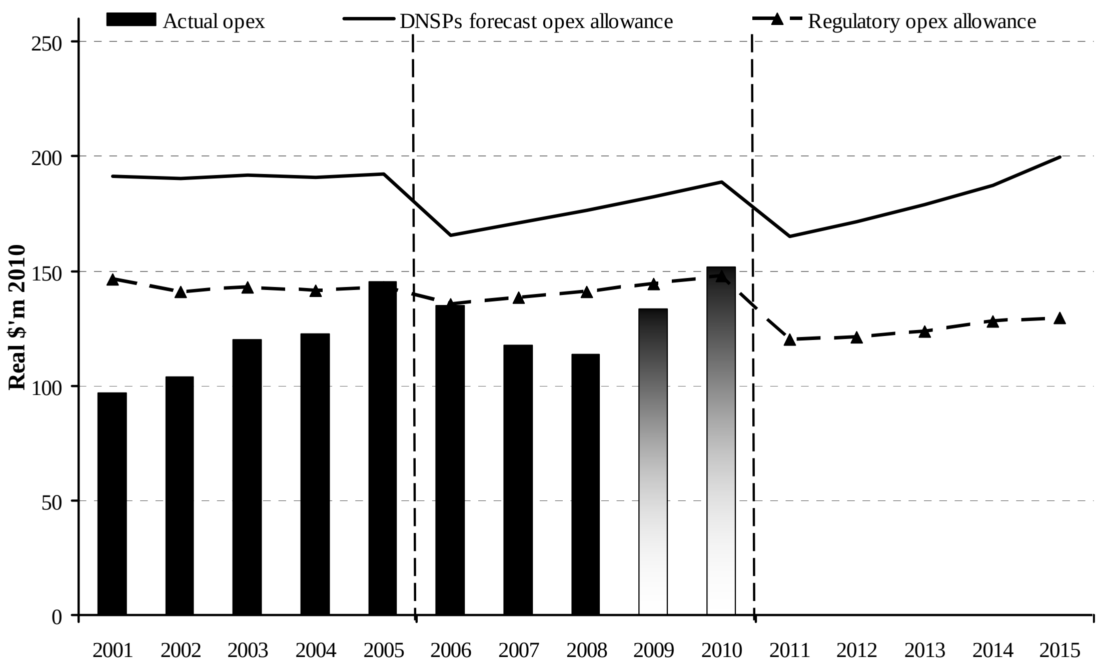


Table 7.32 Jemena draft decision opex allowance ($'m 2010)

	2011	2012	2013	2014	2015	Total (2011–15)
Jemena proposed opex	**62.6**	**61.1**	**62.9**	**66.7**	**66.1**	**319.4**
AER opex build-up						
AER base year costs	44.0	44.0	44.0	44.0	44.0	220.0
AER scale escalation	0.2	0.3	0.5	0.7	0.8	2.5
AER real cost escalation	0.9	1.4	1.8	2.5	2.9	9.5
AER step changes	1.9	1.5	1.2	3.6	2.5	10.7
AER debt raising costs	0.4	0.4	0.4	0.4	0.5	2.2
AER self insurance	0.1	0.1	0.1	0.1	0.1	0.5
AER other[a]	0.2	0.2	0.2	0.2	0.2	1.1
AER total opex	**47.7**	**47.9**	**48.4**	**51.5**	**51.0**	**246.5**
Adjustment	**–14.9**	**–13.2**	**–14.5**	**–15.2**	**–15.1**	**–72.9**
Adjustment (per cent)	**–23.8**	**–21.6**	**–23.1**	**–22.8**	**–22.8**	**–22.8**

(a) DMIS, GSL

Figure 7.7 illustrates the AER's draft decision for Jemena's forecast opex allowance of $247 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.7 Jemena draft decision opex allowance

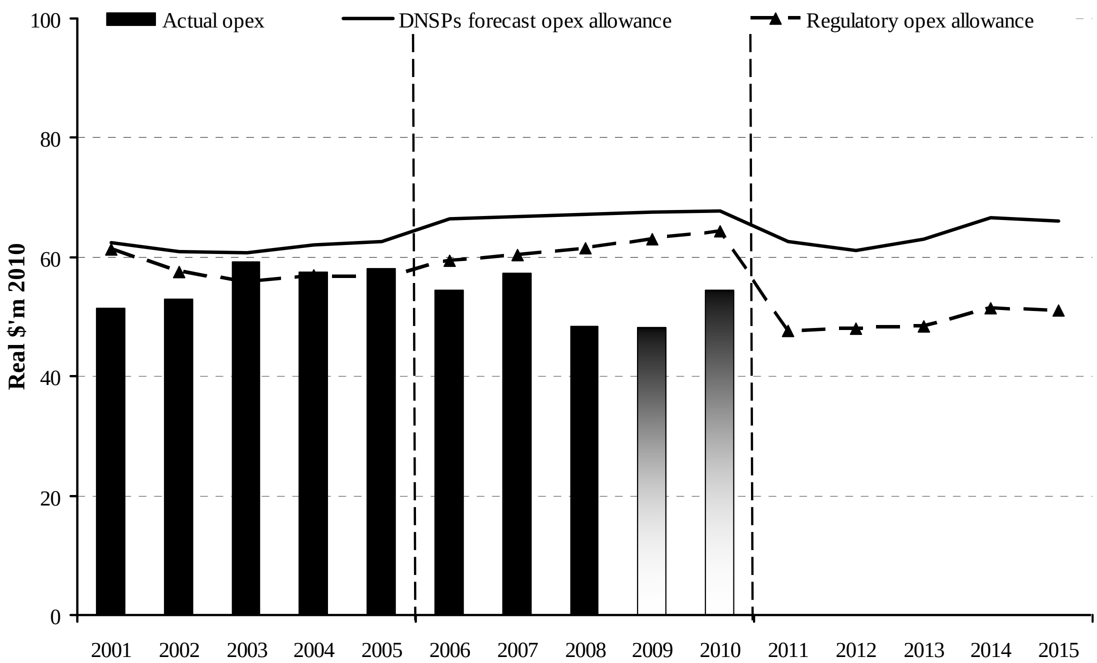


Table 7.33 SP AusNet draft decision opex allowance ($'m 2010)

	2011	2012	2013	2014	2015	Total (2011–15)
SP AusNet proposed opex	**168.4**	**173.4**	**177.5**	**181.7**	**184.7**	**885.7**
AER opex build-up						
AER base year costs	117.6	117.6	117.6	117.6	117.6	588.2
AER scale escalation	0.6	1.1	1.7	2.2	2.8	8.4
AER real cost escalation	1.7	2.7	3.7	5.2	6.2	19.5
AER step changes	4.4	4.1	4.9	5.7	6.0	25.0
AER debt raising costs	1.1	1.1	1.2	1.2	1.3	6.0
AER self insurance	–	–	–	–	–	–
AER other[a]	4.9	4.9	4.9	4.9	4.9	24.7
AER total opex	**130.4**	**131.6**	**134.0**	**136.9**	**138.8**	**671.8**
Adjustment	**–38.0**	**–41.8**	**–43.5**	**–44.7**	**–45.8**	**–213.9**
Adjustment (per cent)	**–22.6**	**–24.1**	**–24.5**	**–24.6**	**–24.8**	**–24.2**

(a) DMIS, GSL

Figure 7.8 illustrates the AER's draft decision for SP AusNet's forecast opex allowance of $672 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.8 SP AusNet draft decision opex allowance

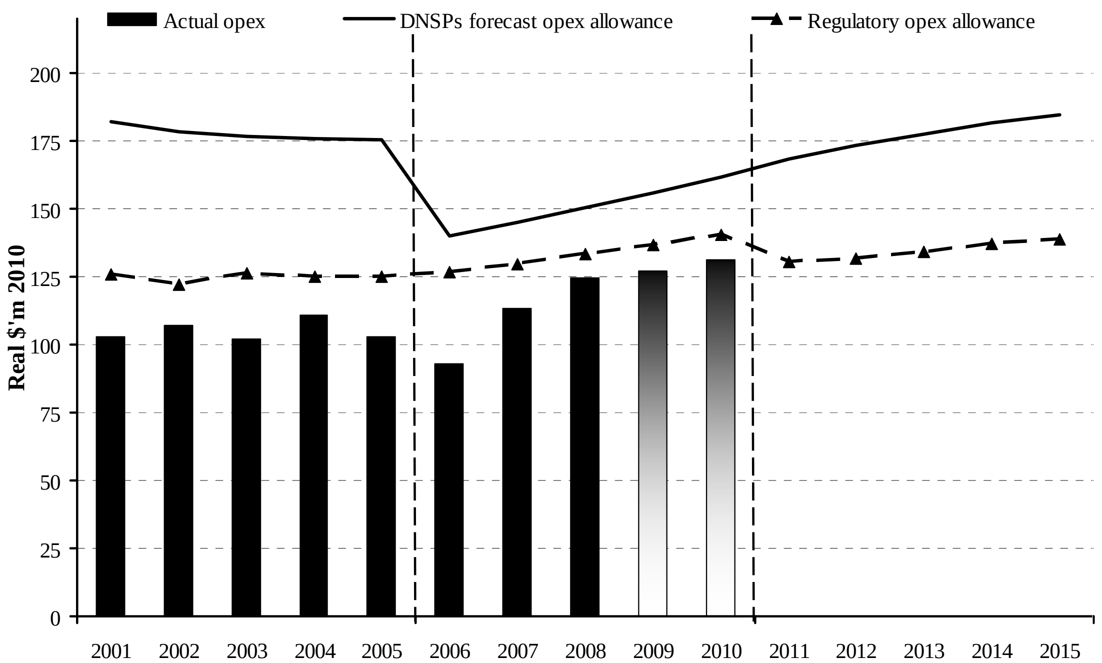


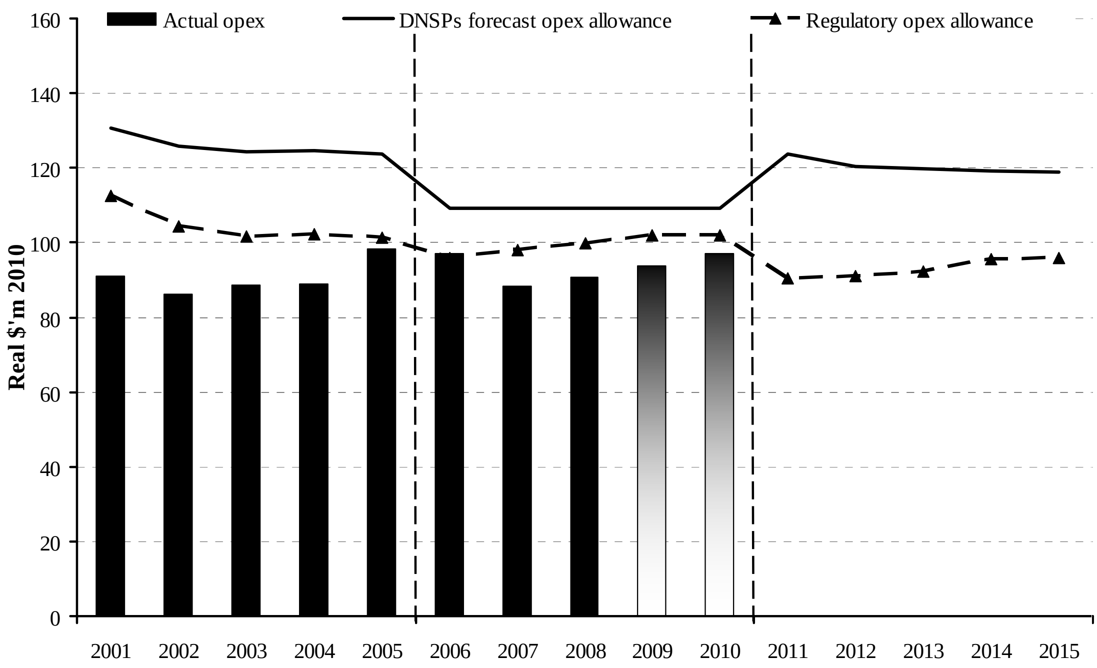
Table 7.34 United Energy draft decision opex allowance ($'m 2010)

	2011	2012	2013	2014	2015	Total (2011–15)
United Energy proposed opex	**123.8**	**120.2**	**119.7**	**119.2**	**118.9**	**601.8**
AER opex build-up						
AER base year costs	85.0	85.0	85.0	85.0	85.0	424.8
AER scale escalation	0.3	0.6	0.9	1.2	1.5	4.6
AER real cost escalation	1.6	2.4	3.4	4.7	5.5	17.6
AER step changes	2.2	1.6	1.6	3.0	2.4	10.9
AER debt raising costs	0.8	0.8	0.8	0.8	0.8	4.0
AER self insurance	0.0	0.0	0.0	0.0	0.0	0.1
AER other[a]	0.7	0.7	0.7	0.7	0.7	3.3
AER total opex	**90.5**	**91.1**	**92.4**	**95.4**	**95.9**	**465.3**
Adjustment	**–33.3**	**–29.1**	**–27.3**	**–23.8**	**–23.0**	**–136.5**
Adjustment (per cent)	**–26.9**	**–24.2**	**–22.8**	**–19.9**	**–19.3**	**–22.7**

(a) DMIS, GSL

Figure 7.9 illustrates the AER’s draft decision for United Energy's forecast opex allowance of $465 million compared to current and previous proposals, prior regulatory opex allowances and actual opex.

Figure 7.9 United Energy draft decision opex allowance



8 Forecast capital expenditure

8.1 Introduction

This chapter sets out the AER's conclusions on forecast capital expenditure (capex) allowances for the Victorian DNSPs for the forthcoming regulatory control period. It also:

- provides a general overview of the proposals
- addresses comments made by stakeholders on the proposals
- discusses the framework the AER has applied in assessing each proposal against the requirements set out at clause 6.5.7 of the National Electricity Rules (NER)
- summarises the AER's main considerations and responses to stakeholder comments
- sets out the AER's reasons why it does not accept the Victorian DNSPs' forecast capex proposals
- sets out the estimate of the total of each Victorian DNSP's required capex for the forthcoming regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capital expenditure factors (capex factors).

This estimate and the AER's conclusions are set out in section 8.13 of this chapter.

8.2 Regulatory requirements

Under clause 6.12.1(3) of the NER, the AER must decide whether to accept, or reject and form its own estimate of the total of forecast capex included in the building block proposal of each Victorian DNSP on the basis of whether the AER is satisfied the forecast capex proposals reasonably reflect the capex criteria (which in turn refer to the capital expenditure objectives (capex objectives)), taking into account the capex factors. The AER's decision on capex is also set out in the determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

The capex objectives, criteria and factors are set out below.

8.2.1 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.

8.2.2 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.

Under clauses 6.5.7(d) and 6.12.1(3)(ii) of the NER, if the AER is not satisfied that a DNSP's forecast capex allowance reasonably reflects the capex criteria, then the AER cannot accept it and must instead form its own estimate which would reasonably reflect the capex criteria. In accordance with clause 6.12.3(f)(2), this estimate must be the minimum adjustment to the forecast capex proposals necessary to comply the NER.

8.3 Summary of Victorian DNSP regulatory proposals

Together, the Victorian DNSPs proposed a total capex of $5.4 billion ($2010) for the forthcoming regulatory control period. This is approximately 66 per cent (in real terms) higher than the expected capex in the current regulatory control period. The amounts proposed by the Victorian DNSPs are set out in table 8.1.

Table 8.1 Victorian DNSPs' proposed total capex ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	474.5	196.3	213.9	218.6	216.3	212.9	1058.1	123
Powercor	944.5	300.5	302.0	316.1	334.5	334.5	1587.5	68
Jemena	327.6	126.6	130.3	122.0	109.4	111.3	599.7	83
SP AusNet	995.8	265.9	297.8	273.3	277.8	256.8	1371.5	38
United Energy	520.5	179.5	169.3	164.9	148.5	127.8	790.0	52
Total	**3262.8**	**1068.8**	**1113.4**	**1094.8**	**1086.5**	**1043.3**	**5406.9**	**66**

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

CitiPower

CitiPower's forecast capex proposal is 123 per cent higher than expected capex in the current regulatory control period. The main categories of the forecast capex proposal to increase are reinforcement, reliability and quality maintained and new connections. CitiPower identified the following key drivers for the increases in its forecast capex proposal:

- Increased reinforcement expenditure from $75 million in the current regulatory control period to $301 million in the forthcoming regulatory control period to accommodate capacity growth after a period of increasing network utilisation and cost pressures due to peak demand growth. The majority of the reinforcement expenditure relates to two large projects, the Metro 2012 capacity upgrade, and the CBD security of supply upgrade project.

- New customer connections expenditure totalling $476 million ($303 million net of customer contributions). CitiPower stated that this expenditure is required to ensure it can deliver all requested works to customers, including embedded generators.

- Ramp up in replacement programs to begin mitigating aged asset risks.

Powercor

Powercor's forecast capex proposal is 68 per cent higher than expected capex in the current regulatory control period. The main areas of the forecast capex proposals are increases in reinforcement, reliability and quality maintained, new connections, and non-network IT. Powercor identified the following key drivers for the increases in its forecast capex:

- Increased reinforcement expenditure from $146 million in the current regulatory control period to $311 million in the forthcoming regulatory control period. Powercor stated that investment in low cost capacity options in the current regulatory control period has allowed deferment of large capital expenditure. However, such low cost options have been exhausted, hence the need for increased reinforcement expenditure over the forthcoming regulatory control period.

- New customer connections gross expenditure totalling $791 million for for the forthcoming regulatory control period ($507 million net of customer contributions). Powercor stated that this expenditure is required to ensure it can deliver all requested works to customers, including embedded generators.

- Reliability and quality maintained expenditure of $464 million in the forthcoming regulatory control period. As with CitiPower, Powercor states that this expenditure is required to address all condition-based deterioration and defects and to replace all assets that have failed in service.

Jemena

Jemena's forecast capex proposal is 83 per cent higher than expected capex in the current regulatory control period. The main areas where the forecast capex proposal increases are reinforcement and reliability and quality maintained. According to Jemena, the increase in reliability and quality maintained is mainly driven by increased age/condition related asset replacement and the need for a number of performance related programs to maintain reliability and quality to the target levels. Jemena stated that the additional performance works are required due to the degradation expected in the forthcoming regulatory control period through climate change and degradation in asset failure rates that have occurred historically.

SP AusNet

SP AusNet's forecast capex proposal is 38 per cent higher than expected capex in the current regulatory control period. The main areas where the forecast capex proposal increases are reinforcement, reliability and quality maintained and new connections. The key drivers of SP AusNet's forecast capex program were identified as:

- New customer connections expenditure of $335 million (net of customer contributions). SP AusNet stated that the 16 per cent increase in this expenditure compared to the current regulatory control period is driven by an increase in unit rates forecast for the forthcoming regulatory control period.

- Reinforcement capex of $404 million compared to $194 million in the current regulatory control period. This increase in reinforcement capex is required to satisfy the 4.4 per cent annual growth in maximum demand and also address the sustained effects of exceptional demand growth during the current regulatory control period. SP AusNet noted that its franchise area includes two of Melbourne's five growth areas designated by the Victorian Government.

- Reliability and quality maintained capex of $322 million. This is a 60 per cent increase compared to the current regulatory control period and is driven by forecast increases in the unit costs and volumes of asset replacement.

United Energy

United Energy's forecast capex proposal is 52 per cent higher than expected capex in the current regulatory control period. United Energy's significant ramp up in replacement programs is intended to begin mitigating aged asset risks.

8.4 Summary of submissions

The AER received submissions from a range of end user representatives, energy retailers, embedded generators and government, including VicUrban, Victorian Employers Chamber of Commerce and Industry (VECCI), Victorian Council of Social Service (VCOSS), Total Environment Centre (TEC), Streetlight Group of Councils, Origin, Victorian Minister for Energy and Resources, Mars Petcare, Energy Users Coalition of Victoria (EUCV), Energy Users Association of Australia (EUAA), Consumer Utilities Advocacy Centre, Consumer Action Law Centre (CALC), Central Victorian Greenhouse Alliance, City of Darebin and the Australian Industry Group.

The submissions raised the following concerns:

- Efficiency and prudency of capex—submissions by Origin, CALC, EUCV, and EUAA questioned the accuracy of DNSPs' forecast capex given historical levels of capex.[1] In particular, submissions by CALC and EUCV noted the trend of DNSPs underspending capex.[2] Additionally, TEC was critical of the NER allowing an automatic roll forward of all capex regardless of whether the capex was within or exceeded the allowance in the regulatory reset.[3]

- Customer contributions forecasts—CALC noted that historically the DNSPs' have been poor in forecasting customer contributions and that the AER should look closely at a more accurate way of forecasting customer contributions.[4] EUCV

1 Origin, February 2010, p. 5–6; Consumer Action Law Centre (CALC), February 2010, p. 11; Energy Users Coalition of Victoria (EUCV), February 2010, p. 4; Energy Users Association of Australia (EUAA), February 2010, p. 8.
2 CALC, February 2010, p. 11, EUCV, February 2010, p. 4.
3 Total Environment Centre, 11 February 2010, p. 28.
4 CALC, February 2010, p. 11, EUCV, February 2010, p. 9.

noted that that the high increase in reinforcement and new connections capex outstripped expected growth in peak demand. [5]

- Deferral or prioritisation of capex—submissions by CALC, Origin and EUCV noted the significant volumes of replacement capex/ageing assets sought by DNSPs and questioned whether deferrals could be considered.[6]

- Cost escalation—EUCV noted the rate of increases in material and labour costs used was higher than general inflation and EUCV considered the AER's approach of allowing larger than CPI adjustments for material based on estimates is inefficient.[7]

- Benchmarking—the need to benchmark DNSPs capex was raised by CALC, VCOSS and EUAA, including a request for the AER to collate and make data available to stakeholders to enable them to more effectively comment on the DNSPs' proposals.[8]

8.5 Consultant review

Specifically, the AER engaged Nuttall Consulting to undertake a set of targeted capex reviews that focussed on areas of significant capex increases.

Nuttall Consulting's reviews included consideration of the Victorian DNSPs' proposals for the regulatory control periods from 2001–05 and 2006–10 as well as the previous allowances set by the previous regulator—the Essential Services Commission of Victoria (ESCV). Nuttall Consulting also reviewed the relative capital efficiencies of the Victorian DNSPs, particularly with respect to other National Electricity Market (NEM) states.

As part of its process of reviewing DNSPs' proposals, Nuttall Consulting undertook a review of the DNSPs' proposals for the regulatory control periods from 2001–10 as well as the previous allowances set by the previous regulator, the Essential Services Commission of Victoria (ESCV). Nuttall Consulting also reviewed the relative capital efficiencies of the DNSPs, particularly with respect to other National Electricity Market (NEM) states.

Nuttall Consulting chose for comparison purposes a plot which compared capex per customer against customer density for each of the NEM DNSPs.[9] This plot shows the Victorian DNSPs generally sit below the regression line. Nuttall Consulting also compared a plot of the ratio of capex to the regulated asset base. Nuttall Consulting concluded from this analysis that the existing level of actual capex was relatively efficient for the Victorian DNSPs. Nuttall Consulting's analysis also found that the historical accuracy of the DNSPs' capex proposals was relatively poor. Forecasting is discussed further in section 8.6.2.

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5 EUCV, February 2010, p. 28.
6 CALC, February 2010, p. 28, Origin, February 2010, p. 5–6; EUCV, February 2010, p. 11–12, 16.
7 EUCV, February 2010, p. 10.
8 CALC, February 2010, p. 11; Victorian Council of Social Service, February 2010, p. 1; EUAA, February 2010, p. 32.
9 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 12.

Nuttall Consulting therefore regarded the existing actual level of DNSP capital expenditure to represent an efficient base or starting point. For this reason, areas where capex was not increasing above historical trends were either not reviewed, or reviewed at a high-level only.

In summary, Nuttall Consulting's review process involved:

- detailed desktop reviews of each Victorian DNSP's capex proposals and supporting information
- examining whether each Victorian DNSP had considered, and made provision for, efficient non–network alternatives
- consideration of the relative prices of operating and capital inputs and the substitution possibilities between opex and capex[10]
- consideration of governance frameworks to ensure capex proposals are line with capex policies and procedures and are consistent with the capex objectives
- meetings with the Victorian DNSPs to discuss particular elements of the capex proposal and the supporting materials
- requesting additional information from the DNSPs to aid Nuttall Consulting's understanding and considerations of the Victorian DNSPs' capex programs and development of views on key issues
- discussion and agreement with the AER on the areas of targeted capex review.

A summary of Nuttall Consulting's overall recommendation is provided in table 8.2.

Table 8.2 Summary of Nuttall Consulting's recommendations (per cent)

DNSP	Reduction from proposals	Increase 2006–08 actual expenditure	Increase 2006–10 estimate
CitiPower	43	87	47
Powercor	38	20	17
Jemena	49	15	1
SP AusNet	41	32	-4
United Energy	34	46	16
Total	**40**	**35**	**13**

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010.

[10] NER clause 6.5.7(e)(6) and clause 6.5.7.(e)(7).

The annual forecast capex resulting from Nuttall Consulting's recommended adjustments are provided in table 8.3.

Table 8.3 Nuttall Consulting's recommended forecast capex ($’m, 2010)

		2011	2012	2013	2014	2015
CitiPower	Proposed capex	132.7	149.1	160.9	159.0	153.5
	Nuttall's view	91.8	89.8	97.4	73.9	79.7
Powercor	Proposed capex	204.6	202.8	215.1	230.3	226.9
	Nuttall's view	123.7	129.3	133.4	138.9	144.5
Jemena	Proposed capex	111.4	114.4	105.2	91.4	91.8
	Nuttall's view	49.0	53.7	53.8	52.6	54.3
SP AusNet	Proposed capex	197.1	232.1	210.3	212.3	184.5
	Nuttall's view	110.4	114.1	120.7	131.3	135.7
United Energy	Proposed capex	157.3	147.3	142.1	126.2	105.9
	Nuttall's view	88.4	89.9	88.8	90.3	93.8
Total	**Proposed capex**	**803.2**	**845.7**	**833.6**	**819.2**	**762.7**
	Nuttall's view	**463.4**	**476.8**	**494.1**	**487.1**	**508.0**

Note: Proposed capex excludes new customer connections as this element of capex was not considered by Nuttall Consulting. Both the proposed capex and the Nuttall Consulting view include direct and indirect overheads, related party margins and costs increases. Due to the targeted approach employed Nuttall Consulting did not review certain categories of some DNSPs forecast capex. For these categories the proposed capex is taken as the Nuttall Consulting's view.

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010.

8.6 Issues and AER considerations overview

8.6.1 AER approach to assessment

The costs as submitted to the AER by the Victorian DNSPs include not only the direct cost of a particular service or activity but also additional cost components for cost increases, overheads and margins. The approach used by the AER to estimate the efficient forecast capex over the forthcoming regulatory control period is to remove margins, overheads, associated cost increases and, where relevant, customer contribution components from the Victorian DNSPs’ forecasts to arrive at a direct cost estimate for each component of the Victorian DNSPs’ proposed capex.

In deciding whether the Victorian DNSPs' forecast capex proposals reasonably reflects the capex criteria, the AER has, as relevant, had regard to the capex factors.

One of the capex factors refers to the analysis undertaken by or for the AER and published before the distribution determination is made in its final form.[11]

The approach in undertaking this analysis has been to determine and examine whether:

- the methods and assumptions which underlie and were used to develop the forecast capex proposal are robust and reflect a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives
- the estimates of real cost escalators and their application reflect a reasonable expectation of input cost forecasts
- the projects and programs that form the forecast capex proposals reflect the capex criteria, including with respect to their scope, timing and costs
- the forecast capex proposals are deliverable and are therefore commensurate with what a prudent DNSP would require to achieve the capex objectives.

Where the AER analysis has found, having regard to the capex factors, that a forecast in relation to a component is satisfactory then the AER has accepted the DNSP's forecast for that component. Where the AER has not been satisfied then the AER is required by the NER to form a view on the minimum necessary adjustment to satisfy the capex criteria.

The AER's approach in this review has been to review what costs may be considered efficient in the circumstances. In most instances where a need to substitute an alternative estimate of the likely cost has arisen, the AER has adopted a 'revealed cost' approach. This approach considers that a well managed DNSP responding to the regulatory incentive framework will not incur inappropriate costs. Therefore, for that DNSP, its historical costs in relation to an activity can be regarded as an efficient base for determining an alternative view for that activity.

To arrive at the AER's view as to the total capex requirement the AER must sum the components and add back its view of the appropriate overheads, associated costs increases, margins and (where relevant) customer contributions.

Overall, these considerations are intended to assist the AER to determine whether it is satisfied that the total forecast capex reasonably reflects the capex criteria listed in clause 6.5.7(c) of the NER.

The characteristics of distribution network activities mean that there is a large number of individual projects and programs. It is neither efficient nor effective for the AER to undertake a detailed review of each and every project. Accordingly, while a range of the Victorian DNSPs' projects and programs were reviewed by the AER and its consultants, the AER's overall assessment has placed less reliance on individual project reviews. Further the AER and its consultants have focused on, as relevant:

11 NER clause 6.5.7(e)(3).

- the methodologies and the underlying assumptions used to determine the forecast capex proposals in order to gauge their reasonableness
- general factors (for example, trends in asset age, faults etc) and methods (for example, expenditure modelling) in examining the investment proposed in the network
- departures from identified trends in historical expenditure formulated through comparative analysis techniques.

The AER notes that this analysis at times involves and overlaps with its consideration of the other capex factors listed at clause 6.5.7(e).

In assessing and determining whether each of the Victorian DNSPs’ proposed capex forecast reasonably reflects the capex criteria, the AER has had regard the capex factors as relevant. Specifically the AER’s analysis of forecast capex takes into account:

- the information included in or accompanying the building block proposal.[12]

This draft decision (which should be read in conjunction with the relevant appendices chapter) sets out the AER’s analysis of the information provided to the AER as part of the building block proposals.

- submissions received in the course of consulting on the building block proposal.[13]

This draft decision (which should be read in conjunction with the relevant appendices chapter) sets out the AER’s response to submission received in the course of consulting on the building block proposal.

- analysis undertaken by or for the AER and published before the distribution determination is made in its final form.[14]

This draft decision (which should be read in conjunction with the relevant chapters and appendices) sets out the analysis undertaken by the AER and its consultants in determining each DNSP's capex allowance.

- benchmark capex that would be incurred by an efficient DNSP over the regulatory control period.[15]

This draft decision (which should be read in conjunction with the relevant chapters and appendices) sets out the consideration by the AER and its consultants of benchmark capex requirements in determining each DNSP's capex allowance.

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[12] NER clause 6.5.7(e)(1).
[13] NER clause 6.5.7(e)(2).
[14] NER clause 6.5.7(e)(3).
[15] NER clause 6.5.7(e)(4).

- the actual and expected capex of the DNSP during any preceding regulatory control periods.[16]

This draft decision (which should be read in conjunction with the relevant chapters and appendices) sets out the consideration by the AER and its consultants of actual and expected capex in a previous regulatory control period in determining each DNSP's capex allowance.

- the relative prices of operating and capital inputs.[17]

This draft decision (which should be read in conjunction with the relevant chapters and appendices) sets out the consideration by the AER and its consultants of the relative prices of operating and capital inputs in determining each DNSP's capex allowance.

- the substitution possibilities between opex and capex.[18]

This draft decision (which should be read in conjunction with the relevant chapters and appendices) sets out the consideration by the AER and its consultants of the substitution possibilities between opex and capex in determining each DNSP's capex allowance.

- 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.[19]

This draft decision (which should be read in conjunction with the relevant chapters and appendices) sets out the consideration by the AER and its consultants of whether the total labour costs included in the capex and opex forecasts are consistent with the incentives provided by the applicable service target performance incentive scheme in determining each DNSP's capex allowance.

- 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[20]

This draft decision (which should be read in conjunction with the relevant chapters and appendices) also sets out the analysis undertaken by the AER of related party margins in determining each DNSP's capex allowance.

- the extent the DNSP has considered, and made provision for, efficient non-network alternatives.[21]

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16 NER clause 6.5.7(e)(5).
17 NER clause 6.5.7(e)(6).
18 NER clause 6.5.7(e)(7).
19 NER clause 6.5.7(e)(8).
20 NER clause 6.5.7(e)(9).
21 NER clause 6.5.7(e)(10).

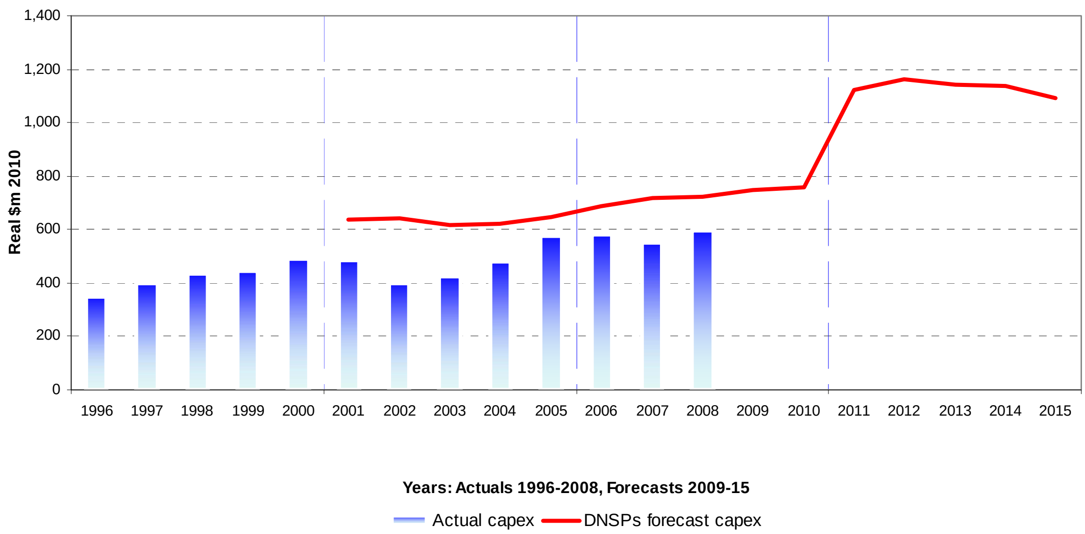
This draft decision (which should be read in conjunction with the relevant chapters and appendices) also sets out the analysis undertaken by the AER and its consultants of whether the DNSPs had considered efficient non–network alternatives in determining each DNSP's capex allowance.

8.6.2 Actual expenditure versus forecast

Two of the capex factors the AER must have regard to is the benchmark capex that an efficient Victorian DNSP would incur over the forthcoming regulatory control period and the actual and expected capital expenditure that DNSP respectively incurred or was allowed to incur during any preceding regulatory control periods.[22]

Trend analysis plays an important role here. The trend analysis the AER has undertaken tests the forecasting performance of DNSPs and assess their actual expenditure in comparison to these forecasts and assess trends in DNSPs capital expenditure.[23]

Figure 8.1 Capital expenditure trend analysis



Source: AER internal analysis.

In figure 8.1 above, DNSPs’ forecast capex represents the capex forecast by DNSPs, starting in 2001 through to the forthcoming regulatory control period ending in 2015. Actual capex represents the actual capex of DNSPs in the current and previous regulatory control periods. The DNSPs forecasts of their capex over 2001–08 are significantly higher than the actual capex spent by DNSPs over 2001–08.

The AER’s trend analysis indicates that DNSPs’ past capital expenditure forecasts have been high and that DNSPs are again forecasting significant growth in their capital expenditure in the forthcoming regulatory control period. DNSPs’ actual

22 NER clause 6.5.7(e)(4) and (5).

23 For additional details surrounding the AER’s benchmarking and trend analysis investigation see Appendix I of this draft decision.

capital expenditures on the other hand have been substantially below their forecast allowance consistently over time.

A major feature of an incentive based regulatory framework is that the regulated firm should achieve efficiency gains whereby actual expenditure is lower than the forecast. However, equally it is the case that the regulator must take great care to ensure that the forecasts adopted are accurate and well substantiated as the observed difference in figure 8.1 may be due to efficiency gains, forecasting errors or to some combination of the two competing explanations. This AER's trend analysis suggests that the DNSPs' capital expenditure forecasts tend to systematically over estimate capital expenditure. DNSPs appear to spend significantly less than forecast, and previously allowed, and DNSPs’ actual capital expenditure tends to follow a fairly gradually increasing trend.

8.6.3 Forecasts for reliability and quality maintained capital expenditure programs resulting from the Victorian Bushfire Royal Commission

In 2009, the Victorian Government established the Victorian Bushfire Royal Commission (VBRC) to investigate the cause of the February 2009 bushfires. Although two interim reports have been issued by the VBRC, at the time of this draft decision, the VBRC had not issued its final recommendations to the Victorian Government. Both the AER and the Victorian DNSPs note that the VBRC is expected to make recommendations that include increased activities in reducing future bushfire risks. The AER recognises that implicit in the DNSPs' regulatory proposals are a range of current and future activities that may impact on future bushfire risks. Many activities such as the renewal of ageing assets are undertaken as a matter of good industry practice and are broadly categorised as expenditure to ensure targets for reliable electricity continue to be met. It is self-evident that some of this activity will directly impact on bushfire risk even if it has not been undertaken with fire risk reduction as the primary objective.

The AER cannot pre-empt either the VBRC's recommendations or the government's response. The DNSPs proposed that this uncertainty may best be dealt with as a pass through application at a later date. Subject to the requirements of approving cost pass throughs in clause 6.6.1 of the NER, the AER agrees with this approach in principle.

The AER recognises that the forecast capex proposals include future conductor replacement activities that may impact on future bushfire risks. In the case of SP AusNet and Powercor, Nuttall Consulting noted that there is an economic case for enhanced activity in relation to the renewal of ageing overhead line assets (that is, conductors) however expressed concerns that the Victorian DNSPs may not be able to accurately target this expenditure. On this basis, Nuttall Consulting recommended that the AER 'ring-fence' this proposed activity pending a revised submission from the DNSPs.

The AER agrees with Nuttall Consulting that there is an economic case for enhanced activity in relation to the renewal of ageing overhead line assets and the concern that the Victorian DNSPs may not be able to accurately target this expenditure. However, in respect of Nuttall Consulting’s recommendation, the AER is unable to defer consideration of future conductor replacement activities. This is because clause

6.12.1(3) of the NER requires it either to accept or to not accept a forecast capex proposal in which case the AER must estimate the required capex it is satisfied with that reasonably reflects the capex criteria. As there is an economic case for the renewal of ageing overhead line assets, in consultation with Nuttall Consulting, the AER has estimated the amount of capex required for an enhanced level of conductor replacement activity to be undertaken in the forthcoming regulatory control period.

The AER also recognises that SP AusNet and Powercor in particular are exposed to high bushfire risk zones. For this reason the AER has also estimated an enhanced allowance for capital expenditure activities to mitigate bushfire risk. The AER's view of conductor replacement activity for each Victorian DNSP is discussed in section 8.9.6 of this chapter. The Victorian DNSPs will have an opportunity to make further submissions on this matter in their revised proposals.

8.6.4 Forecast reliability and quality maintained expenditure resulting from the AECOM climate change report

The AER has reviewed the AECOM reports on climate change effects as submitted by each Victorian DNSP. These reports demonstrate the likelihood of climate change effects over the medium to longer term. The AER considers that while it is likely that there is some prospect that the claimed effects will become significant over time, a particular concern is that the AECOM reports adopt climate change models that attempt to measure the impact of events over the next few decades to forecast effects likely in the near term. The models adopted are not fit for short term forecasting and the claimed effects have been rejected on this basis.

Further, the AECOM reports do not demonstrate any material shifts in asset ageing or deterioration nor in operating conditions sufficient to materially alter the expected future demand or power system capability in the forthcoming regulatory control period. However, the AER agrees with AECOM’s assessment that currently there is no model capable of accurately predicting climate change effects over the forthcoming regulatory control period. That being said, the AER considers that the effects of climate change on the DNSPs will continue to emerge progressively over time. As circumstances change, there will be measured responses by the DNSPs in their planning and operating procedures which, over time, will cause the technical and financial effects to crystallise. Therefore, the AER considers any climate change effects on the DNSPs will be gradual and may be dealt with progressively as they arise in future regulatory control periods.

8.6.5 AER view on margins, overheads, cost increases

CitiPower’s, Powercor’s, Jemena’s and SP AusNet's proposed capital expenditure forecasts for the forthcoming regulatory control period included, in addition to the direct capital expenditure costs, allowances for margins paid to related party service providers, direct and indirect overheads and real cost increases. United Energy only separately identified real cost increases in its proposed capital expenditure forecast, as its forecasts are heavily based on outsourced contracts.

The breakdown of the Victorian DNSPs’ forecast capex proposals into gross direct capex, overheads, cost increases, margins and customer contributions identified are shown in table 8.4 to table 8.8 below. This has been produced based on the RIN templates, additional information provided by the Victorian DNSPs and analysis undertaken by the AER.

Table 8.4 CitiPower proposed gross capex, overheads, cost increases, margins and customer contributions ($’m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	433.0	191.7	203.6	197.2	187.7	181.7	961.9	122
Direct overheads	55.3	15.2	16.0	16.4	17.1	17.4	82.2	49
Indirect overheads	60.2	15.6	16.3	16.6	17.2	17.4	83.2	38
Cost increases	0.0	4.3	8.6	13.3	17.1	20.3	63.5	–
Margins	23.0	7.3	7.9	8.0	8.6	8.1	39.8	73
Less contributions	-96.9	-37.7	-38.6	-33.0	-31.3	-32.0	-172.6	78
Total net capex	**474.5**	**196.3**	**213.9**	**218.6**	**216.3**	**212.9**	**1058.1**	**123**

Source: CitiPower Regulatory Proposal, RIN template 2.1.

Table 8.5 Powercor proposed gross capex, overheads, cost increases, margins and customer contributions ($’m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	1067.1	303.4	300.7	308.8	320.1	314.8	1547.7	45
Direct overheads	25.5	8.5	8.6	8.8	9.0	9.1	43.9	72
Indirect overheads	108.3	23.6	24.3	25.1	25.8	26.2	125.0	15
Cost increases	0.0	6.7	12.4	18.6	25.2	32.8	95.7	–
Margins	31.8	11.1	10.8	11.1	13.0	12.3	58.3	83
Less contributions	–288.2	–52.8	–54.8	–56.3	–58.5	–60.7	–283.1	–2
Total net capex	**944.5**	**300.5**	**302.0**	**316.1**	**334.5**	**334.5**	**1587.5**	**68**

Source: Powercor Regulatory Proposal, RIN template 2.1

Table 8.6 Jemena proposed gross capex, overheads, cost increases, margins and customer contributions ($’m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	339.4	120.4	122.0	114.3	103.0	103.9	563.5	66
Direct overheads	41.6	17.3	17.8	16.8	15.2	15.4	82.5	98
Indirect overheads	–	–	–	–	–	–	–	–
Cost increases	0.0	1.8	3.6	5.0	5.7	7.0	23.2	–
Margins	–	–	–	–	–	–	–	–
Less contributions	–53.4	–13.0	–13.1	–14.0	–14.5	–15.0	––69.5	30
Total net capex	**327.6**	**126.6**	**130.3**	**122.0**	**109.4**	**111.3**	**599.7**	**83**

Source: Jemena Regulatory Proposal, RIN template 2.1.
Note: Due to Jemena’s claims for confidentiality, Jemena’s direct overheads, indirect overheads and related party margins have been aggregated into direct overheads.

Table 8.7 SP AusNet proposed gross capex, overheads, cost increases, margins and customer contributions ($’m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	965.0	245.6	267.0	240.2	243.3	220.5	1216.5	26
Direct overheads	73.2	15.4	17.4	16.4	16.2	16.0	81.4	11
Indirect overheads	73.2	15.4	17.4	16.4	16.2	16.0	81.4	11
Cost increases	0.0	6.9	12.6	16.1	18.4	22.3	76.3	–
Margins	2.3	1.0	1.0	1.0	1.0	1.0	4.9	108
Less contributions	–118.0	–18.3	–17.5	–16.8	–17.3	–19.0	––89.0	–25
Total net capex	**995.8**	**265.9**	**297.8**	**273.3**	**277.8**	**256.8**	**1371.5**	**38**

Note: SP AusNet reported all overheads as indirect. Consistent with the approach on opex (chapter 7) the AER has allocated their overheads 50 per cent to direct overheads and 50 per cent to indirect overheads. Also see chapter 13 for further discussion.
Source: SP AusNet, Regulatory Proposal, RIN template 2.1.

As United Energy's forecasts are heavily based on outsourced contracts, there is no separate allowance for overheads, cost increases or margins in the forthcoming regulatory control period.

Table 8.8 United Energy proposed gross capex, overheads, cost increases, margins and customer contributions ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
Gross direct capex	579.6	194.2	184.3	179.6	163.2	142.5	863.8	49%
Direct overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	–
Indirect overheads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	–
Cost increases	0.0	8.0	7.8	9.7	10.8	10.8	47.0	–
Margins	4.3	0.0	0.0	0.0	0.0	0.0	0.0	-100%
Less contributions	-63.5	-22.7	-22.8	-24.4	-25.5	-25.5	-120.9	90%
Total net capex	**520.5**	**179.5**	**169.3**	**164.9**	**148.5**	**127.8**	**790.0**	**52%**

Source: United Energy Regulatory Proposal, RIN template 2.1.

The AER's assessment of the forecast capex proposals in sections 8.7 to 8.12, are based on direct costs and excludes the Victorian DNSPs' forecasts of related party margins, overheads and real cost increases. The AER has undertaken a separate assessment of the Victorian DNSPs' proposed related party margins, overheads and real cost increases and has then applied its draft determination on these elements of capital expenditure to the total draft decision capital expenditure allowance for each Victorian DNSP. The following outlines the AER's draft decision on these elements of each of the Victorian DNSPs' capital expenditure forecasts that applies to all capital expenditure categories.

Related party margins

CitiPower, Powercor, Jemena and SP AusNet included in their proposed forecast capital expenditure an allowance for related party margins, outlined in table 8.9.

Table 8.9 Victorian DNSPs' proposed related party margins ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	23.0	7.3	7.9	8.0	8.6	8.1	39.8	73
Powercor	31.8	11.1	10.8	11.1	13.0	12.3	58.3	83
Jemena	–	–	–	–	–	–	–	–
SP AusNet	2.3	1.0	1.0	1.0	1.0	1.0	4.9	108
United Energy	4.3	0.0	0.0	0.0	0.0	0.0	0.0	–

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

Note: Due to Jemena's claims for confidentiality, Jemena's proposed related party margins have not been separately identified.

The AER has assessed the reasonableness of each DNSP's proposed margins for related party transactions, which are applied to the proposed expenditure forecasts, in chapter 6 of this draft decision.[24] The AER concluded in chapter 6 that the margins for all related party transactions proposed by CitiPower, Powercor, Jemena and SP AusNet have not been adequately justified as prudent and efficient—see chapter 6 for further details of the AER's conclusions.

In making its assessment of related party margins that the DNSPs applied to their proposed capital expenditure forecasts, the AER has adopted the reasoning and conclusions reached on margins for related party transactions in chapter 6. The AER has therefore not allowed for any related party margin in its conclusions on capital expenditure for CitiPower, Powercor, Jemena and SP AusNet. United Energy did not propose a related party margin in relation to its capex forecast.

Table 8.10 AER conclusion on related party margins ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	0.0	0.0	0.0	0.0	0.0	0.0
Powercor	0.0	0.0	0.0	0.0	0.0	0.0
Jemena	0.0	0.0	0.0	0.0	0.0	0.0
SP AusNet	0.0	0.0	0.0	0.0	0.0	0.0
United Energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Direct overheads

CitiPower, Powercor, Jemena and SP AusNet included an allowance for direct overheads as part their forecast capex proposals, as shown in table 8.11.

[24] NER clause 6.5.7(e)(9).

Table 8.11 Victorian DNSPs' proposed direct overheads ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	55.3	15.2	16.0	16.4	17.1	17.4	82.2	49
Powercor	25.5	8.5	8.6	8.8	9.0	9.1	43.9	72
Jemena	–	–	–	–	–	–	–	–
SP AusNet	73.2	15.4	17.4	16.4	16.2	16.0	81.4	11
United Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	–

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

Note: Due to Jemena's claims for confidentiality, Jemena's proposed direct overheads have not been separately identified.

The AER considers that it is reasonable to allow for direct overheads in the forthcoming regulatory control period. However, the basis of the proposed rate of direct overheads was not clear to the AER, and has not been supported in any documentation provided in the Victorian DNSPs' regulatory proposals. The AER is therefore not satisfied that the forecast direct overheads by CitiPower, Powercor, Jemena and SP AusNet reasonably reflect the efficient costs to achieve the capex criteria including the capex objectives.

The AER considers that historical direct overheads incurred provides a reasonable starting point to forecast direct overheads for the forthcoming regulatory control period. The AER has therefore adjusted the proposed direct overheads where the DNSP has forecast direct overheads, as a percentage of direct costs, greater than historical levels. United Energy did not seek an allowance for direct overheads.

The AER has concluded that allowing the direct overheads for CitiPower, Powercor, Jemena and SP AusNet, shown in table 8.12, reasonably reflects the efficient costs to achieve the capex criteria including the capex objectives.

Table 8.12 AER conclusion on direct overheads ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	9.6	9.2	9.6	7.5	7.8	43.6
Powercor	5.1	5.2	5.3	5.4	5.5	26.6
Jemena	1.3	1.3	1.3	1.4	1.4	6.7
SP AusNet	11.4	11.4	11.6	11.9	12.7	59.1
United Energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	**27.4**	**27.1**	**27.9**	**26.2**	**27.4**	**135.9**

Indirect overheads

CitiPower, Powercor, Jemena and SP AusNet have also proposed an allowance for indirect overheads as part of their forecast capex proposals, shown in table 8.13.

Table 8.13 Victorian DNSPs' proposed indirect overheads ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	60.2	15.6	16.3	16.6	17.2	17.4	83.2	38
Powercor	108.3	23.6	24.3	25.1	25.8	26.2	125.0	15
Jemena	–	–	–	–	–	–	–	–
SP AusNet	73.2	15.4	17.4	16.4	16.2	16.0	81.4	11
United Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	–

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

Note: Due to Jemena's claims for confidentiality, Jemena's proposed indirect overheads have not been separately identified.

The AER considers that it is reasonable to allow for indirect overheads in a forecast of capital expenditure. The basis of the proposed rate of indirect overheads used by Jemena and SP AusNet was not clear to the AER, while CitiPower and Powercor provided the calculations to determine its proposed indirect overheads. The AER notes that CitiPower and Powercor have applied its scale and real cost escalators to determine indirect overheads. In addition, CitiPower and Powercor proposed an indirect overhead allowance based on its allocation of costs arising from CitiPower's and Powercor's proposed classification of services. However, the AER has not applied CitiPower's and Powercor's proposed services classification. Accordingly the AER has substituted its own scale and input escalators to the opex and capex forecasts. The AER has not applied CitiPower's and Powercor's method to determine indirect overheads.

To calculate a reasonable level of indirect overheads for CitiPower, Powercor, Jemena and SP AusNet, the AER considers that historical indirect overheads incurred provides a reasonable starting point to forecast direct overheads for the forthcoming regulatory control period. The AER has taken 2009 as the base year from the Victorian DNSPs' regulatory accounts, and has made some adjustments to actual amounts provided in the regulatory accounts. For CitiPower's and Powercor's indirect overheads, the AER has adjusted the 2009 base year indirect overheads to take into account their proposed capitalisation of operating expenditure overheads.

Further, the AER notes that SP AusNet has an element of direct overheads in its base year (as reported in its regulatory accounts). The AER has adjusted for this by assuming that 50 per cent of the 2009 overheads in the base year relates to indirect overheads. The AER has also removed allowances for management fees included in SP AusNet's forecast indirect overheads, consistent with the AER's draft decision on outsourcing and related party transactions—see chapter 6.

To determine the forecast indirect overheads for the forthcoming regulatory control period, the AER has escalated the adjusted 2009 operating expenditure amounts for CitiPower, Powercor, Jemena and SP AusNet for growth and real price increases. The AER's approach to forecast indirect overheads and the application of growth and real price increases is consistent with the AER's approach to forecasting operating expenditure—see chapter 7.

The AER is therefore not satisfied that the forecast indirect overheads by CitiPower, Powercor, Jemena and SP AusNet reasonably reflect the efficient costs to achieve the capex criteria including the capex objectives. The AER made an allowance for indirect overheads in its draft decision on capital expenditure for CitiPower, Powercor, Jemena and SP AusNet consistent with the approach described above, which it considers to be the minimum adjustment necessary to reflect the capex criteria. United Energy did not seek an allowance for indirect overheads.

Table 8.14 AER conclusion on indirect overheads ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	14.4	14.6	14.8	15.1	15.3	74.2
Powercor	22.6	23.0	23.4	23.9	24.2	117.2
Jemena	2.8	2.8	2.9	2.9	3.0	14.4
SP AusNet	14.5	14.5	15.1	15.7	16.1	75.9
United Energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	**54.3**	**55.0**	**56.2**	**57.7**	**58.5**	**281.7**

Real cost increases

CitiPower, Powercor, Jemena, SP AusNet and United Energy in their forecast capex proposals adjusted their forecasts to account for real cost increases in key inputs including copper, aluminium, steel, crude oil, construction costs, sector related and general labour costs, shown in table 8.15.

Table 8.15 Victorian DNSPs’ proposed real cost increases ($’m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total
CitiPower	0.0	4.3	8.6	13.3	17.1	20.3	63.5
Powercor	0.0	6.7	12.4	18.6	25.2	32.8	95.7
Jemena	0.0	1.8	3.6	5.0	5.7	7.0	23.2
SP AusNet	0.0	6.9	12.6	16.1	18.4	22.3	76.3
United Energy	0.0	8.0	7.8	9.7	10.8	10.8	47.0
Total	**0.0**	**27.7**	**45.0**	**62.6**	**77.2**	**93.2**	**305.7**

Source: CitiPower, response to information requested on 10 May 2010, submitted on 13 May 2010; Powercor, response to information requested on 10 May 2010, submitted on 13 May 2010; Jemena, response to information requested on 10 May 2010, submitted on 15 May 2010; SP AusNet, response to information requested on 10 May 2010, submitted on 17 May 2010; United Energy, response to information requested on 10 May 2010, submitted on 14 May 2010.

The AER has undertaken an assessment of the proposed real cost escalators, which is included in appendix K of this draft decision.. The AER's draft decision on each real cost escalator included in appendix K has been used to determine an allowance for real cost increases that reasonably reflects the efficient costs to achieve the capex criteria including the capex objectives.

Table 8.16 AER conclusion on real cost increases ($’m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	6.2	7.7	9.2	8.4	8.8	40.3
Powercor	11.2	14.0	15.9	18.5	19.3	78.9
Jemena	0.8	1.2	1.4	1.7	1.7	6.8
SP AusNet	9.6	11.6	13.2	15.5	16.8	66.7
United Energy	1.8	2.1	2.8	3.9	4.7	15.3
Total	**29.6**	**36.6**	**42.5**	**47.9**	**51.3**	**208.0**

8.7 New customer connections

8.7.1 Victorian DNSP regulatory proposals

The new customer connections category included in standard control capital expenditure includes capital expenditure related to all connections where augmentation of supply is required. Customer contributions are calculated based on the requirements under the Victorian Electricity Industry Guideline No. 14. Although not shown in the table, customer contributions are removed from gross expenditure to determine the net capital expenditure that is rolled into the regulatory asset base. Table 8.17 sets out the Victorian DNSPs’ proposed forecast new customer connection capital expenditure at a gross and net level.

Table 8.17 Victorian DNSPs' proposed new gross and net customer connections capex ($'m, 2010)

		2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	Gross	205.3	83.4	84.5	72.6	68.8	69.9	379.1	85
	Net	108.4	45.7	45.9	39.6	37.5	37.8	206.5	90
Powercor	Gross	576.4	129.4	132.5	134.0	137.1	140.6	673.7	17
	Net	288.2	76.7	77.7	77.7	78.6	79.9	390.6	36
Jemena	Gross	107.0	25.4	26.2	27.6	28.9	30.2	138.2	29
	Net	53.5	12.4	13.1	13.6	14.4	15.2	68.7	28
SP AusNet	Gross	347.1	75.5	71.1	67.0	68.7	74.7	357.0	3
	Net	229.1	57.2	53.6	50.3	51.3	55.7	268.0	17
United Energy	Gross	194.7	42.2	41.9	43.6	43.7	43.0	214.4	10
	Net	131.2	19.5	19.0	19.3	18.2	17.5	93.5	–28.8
Total	**Gross**	**1430.5**	**355.8**	**356.1**	**344.8**	**347.2**	**358.3**	**1762.4**	**23.2**
	Net	**810.5**	**211.4**	**209.3**	**200.4**	**200.0**	**206.1**	**1027.3**	**26.8**

Note: Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1. Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, templates 2.1 and 3.1.

CitiPower and Powercor

CitiPower forecast net capex for new customer connections to increase from $108.4 million ($2010) in the current regulatory control period to $206.5 million ($2010) in the forthcoming regulatory control period. Powercor proposed a forecast for new customer connection net expenditure of $288.2 million ($2010), increasing from $390.1 million ($2010) from the current regulatory control period. CitiPower and Powercor submit the main factors driving increases in new customer connections categories include:

- the reduction in the marginal cost of reinforcement used in the calculation of customer contributions which translates into a decrease in capital contributions received by customers
- forecast increases in project cost for customer connections
- the introduction of a fault level compliance service in the 2011–2015 regulatory control period

- the growth in customer numbers.

CitiPower and Powercor both stated in their regulatory proposals that they generally only know up to six months in advance what customer contributions they are likely to receive from customers. Therefore both CitiPower and Powercor have used 2009 as the base year to determine forecast customer contributions.[25]

Jemena

Jemena has proposed new net customer connections expenditure for the forthcoming regulatory control period of $68.7 million ($2010), increasing from $53.5 million ($2010) from the current regulatory control period. Jemena stated that the level of customer investment is correlated with the level of economic activities in Melbourne, and therefore bases its capital expenditure forecasts on customer number growth as forecast by NIEIR, and business growth forecasts provided by the Construction Forecasting Council.[26]

SP AusNet

SP AusNet proposed $268 million ($2010) in total net customer connections capex over the forthcoming regulatory control period. This is 16 per cent greater than it expects to spend in the current regulatory control period. SP AusNet stated that this increase is to meet the expected customer growth forecasts for the forthcoming regulatory control period and accommodate higher unit costs. SP AusNet also forecast that customer contributions as a proportion of gross customer capital expenditure are forecast to fall from an average 29 per cent in the current regulatory control period to an average of 21 per cent in the forthcoming regulatory control period. This it submitted is due to costs increasing, while amounts customers are liable to contribute remain relatively stable.[27]

United Energy

United Energy has forecast its customer initiated net capital expenditure to be $111 million ($2010) over the forthcoming regulatory control period, decreasing from $131 million ($2010) in the current regulatory control period. United Energy stated that a reduction of customer initiated expenditure for the forthcoming regulatory control period is primarily driven by weaker forecast economic growth, and a one-off major connection in the current regulatory control period. United Energy stated in its regulatory proposal that its forecast is based on five components:

- actual expenditure, using data from recently completed projects
- approved projects, where the customer has accepted United Energy's offer

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[25] CitiPower, *Regulatory proposal*, November 2009, p. 92–98, Powercor, *Regulatory Proposal*, November 2009, pp. 85–91.

[26] Jemena, *Regulatory Proposal: Appendix 10 – Jemena Electricity Networks (Vic) Ltd – Capital and Operational Work Plan (COWP) 2010–15* (Confidential), 30 November 2009, pp. 13–15.

[27] SP AusNet, *Regulatory Proposal*, November 2009, pp. 163–169.

- pending projects, where the customer has not yet confirmed acceptance of United Energy's offer
- horizon projects, where only limited details are known at this time
- forecast projects, where the projects have not been yet been identified.[28]

8.7.2 Submissions on DNSP regulatory proposals

The Consumer Action Law Centre (CALC) raised in its submission that it was concerned that distributors are very poor at forecasting customer contributions and that the AER should look closely at a more accurate way of forecasting customer contributions.[29] The CALC also suggested estimating customer contributions by dividing forecast capex by forecast customer contributions.[30]

8.7.3 AER considerations

The AER undertook a review of historical and forecast gross capex and net capex (and therefore the percentage of customer contributions), the gross unit cost and the number of customer connections to determine whether the forecast new customer connections capex is consistent with the capex requirements of the NER. As discussed in section 8.6.5, this analysis has been undertaken at the direct cost level, and has excluded an assessment of expenditure related to margins, overheads and real cost increases. To assist with this review of new customer connections, the AER requested that the Victorian DNSPs provide a breakdown of customer connections expenditure and connection numbers by customer type for the current and forthcoming regulatory control periods. The AER also sought further explanation from the Victorian DNSPs where significant changes from actual historical data were being forecast, resulting in significant increases in net capex.

In assessing and determining whether each of the Victorian DNSPs' proposed new customer connections forecast capex reasonably reflects the capex criteria, the AER has had regard to the capex factors as relevant. In addition to capex factors 1, 2 and 3, the AER's analysis of forecast new customer connections expenditure capex takes into account:

- benchmark capex that would be incurred by an efficient DNSP over the regulatory control period.[31]

Appendix I to this draft decision (which should be read in conjunction with this chapter) sets out the AER's analysis which benchmarks the Victorian DNSPs against their interstate counterparts including benchmarking the DNSPs' forecasts against the AER's forecasts. The AER considered whether it could assess the efficient level of new customer connections capex for the forthcoming regulatory control period by applying a similar benchmark approach.

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[28] United Energy, *Regulatory Proposal*, November 2009, pp. 109–111.
[29] Consumer Action Law Centre, Submission, January 2010, p. 9.
[30] Consumer Action Law Centre, Submission, January 2010, p. 22.
[31] NER clause 6.5.7(e)(4).

- the actual and expected capex of the DNSP during any preceding regulatory control periods.[32]

The AER has compared the actual capex incurred during the current and previous regulatory control periods against the DNSPs' proposed capex and the AER’s estimate of the required capex for the forthcoming regulatory control period taking into account any observed trends in actual capex.

Regarding forecast customer contributions, the AER notes CALC's submission to this review process concerning how customer contributions were under forecast in the past and how businesses subsequently over recovered customer contributions. The AER has assessed the Victorian DNSPs' forecast customer contributions to ensure that the estimates are consistent with historical levels, and where it deviates, reasonable justification has been made consistent with the capex criteria.

X factor customer contribution calculation issue

During the review process, an issue has arisen in relation to an incompatibility between how customer contributions for connection assets were calculated and applied under the Victorian Electricity Industry Guideline 14 and how the AER calculates and applies X factors under the NER. Under the NER, the X factor is applied to smooth the price path in the forthcoming regulatory control period whereas under Guideline No. 14, the X factor was applied as an efficiency measure.

Using the Victorian DNSPs' proposed X factors for the final year of the forthcoming regulatory control period results in a significant increase in the estimated incremental revenue component used in the calculation of new customer contributions for the forthcoming regulatory control period, which leads to substantially lower contributions by customers to connection works. The practical consequence of this is that the DNSPs have over forecast expected future customer contributions and therefore under estimated net capex. However, based on the X factors in the final year included in this draft decision the impact on net capex would be less significant—refer to chapter 18.

In relation to addressing the X factor in calculating customer contributions, the AER and the DNSPs sought advice from the Department of Primary Industries (DPI). DPI recommended that both the AER and DNSPs should consider the interactions between the average distribution price levels, customer contributions and net capital expenditure and whether a different X factor needs to be set in the final year to better reflect the forecast trajectory of distribution prices. DPI alternatively recommended that the AER consider requesting the ESCV to amend Guideline No. 14 to address this issue.[33]

At the time of this draft decision, the Victorian DNSPs' proposed calculation of customer contributions does not meet the requirements of Guideline No. 14. The AER

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32 NER clause 6.5.7(e)(5).

33 ACIL Tasman (Marianne Lourey) and PWC(Jeff Balchin) for the Victorian Department of Primary Industries, *Consultancy paper on customer contributions*, April, 2010.

has instead calculated customer contributions on the basis of historical levels (in percentage terms) as a placeholder for the purposes of this draft decision.

Pending the resolution of the issues outlined above, the AER considers that the Victorian DNSPs in their revised proposals must calculate customer contributions in accordance with Guideline No, 14. The AER will review the DNSPs' revised X factors and estimates of their customer contributions as part of the final decision.

CitiPower and Powercor

The AER in its assessment of CitiPower’s and Powercor's proposed customer connections expenditure found that new customer connections were forecast to increase significantly for both DNSPs—75 per cent for CitiPower and 42 per cent for Powercor. This increase is largely driven by forecast expenditure for co-generation projects, and proposed expenditure related to residential and business subdivisions. The AER sought further explanation of this increase and specifically the categories of new customer connections that have been forecast to increase significantly.

In March 2010, following AER queries, CitiPower and Powercor revised their forecasts for new customer connections expenditure. CitiPower reduced its forecast new customer connections net capital expenditure from $206 million to $185 million for the forthcoming regulatory control period, while Powercor reduced its forecast to $300 million from $390 million, at the direct cost level.

The AER sought details of the model used by each DNSP to forecast its anticipated customer connections. However, as forecast connections/jobs were not provided, this did not allow the AER to undertake analysis of unit costs by connection type as was undertaken for other DNSPs. The AER considers that an efficient DNSP should have regard to the likely number of connections/jobs in making its forecast.

From the customer connection models provided to the AER, it was found that CitiPower and Powercor used 2009 as a starting point to determine their forecasts.[34] The AER agrees that historical data should be used to determine the forecasts, though the AER considers that using actual reported expenditure from the current regulatory control period provides a more accurate basis to forecast expenditure rather than one year of data. The AER found inconsistencies with the data used in the models for 2009 to the data provided that reconciled with the data provided to the AER in their respective RIN templates. The AER has therefore used only historical data that reconciles with the RIN templates.

In determining their forecast new customer connections expenditure, CitiPower’s and Powercor's forecasts have also applied growth in total customer numbers to its forecast new customer connections. The AER does not agree that this approach is reasonable as growth in connections expenditure should only occur if the number of new connections/jobs is forecast to change. Given that customer growth rates are forecast to be reasonably consistent with historical levels, the AER considers that it is reasonable to use average historical expenditure as the basis for the forecast.

[34] CitiPower, *Customer connection model*, (March update), Powercor, *Customer Connection model*, (March update).

Based on this assessment the AER is therefore not satisfied that the proposed forecast gross customer connections by CitiPower and Powercor reasonably reflect the efficient costs to achieve the capex criteria including the capex objectives. To determine an estimate that reasonably satisfies the capex criteria, the AER has adjusted CitiPower's forecast gross expenditure by applying the 2006–09 average gross connection expenditure for residential and business subdivision projects and low voltage connections with customer supply capacity at greater than 500 kVA. The AER notes that CitiPower has proposed the CUB connection as a major connection within its forecast of low voltage connections with customer supply capacity at greater than 500 kVA. The AER notes that the timing of the work is dependent upon CitiPower's obligation agreement between CitiPower and the customer, which is currently in the early stages of development.[35] Based on the information provided, the AER considers that there is not sufficient evidence that the project will take place within the proposed timing. Given this, the AER considers that allowing average historical expenditure within this category provides a reasonable forecast of expenditure for this category.

With regard to Powercor's forecast new customer connections capital expenditure, based on the assessment described above, the AER did not consider that the increase in expenditure for residential subdivisions and HV connections had been adequately justified as prudent and efficient expenditure in accordance with the capex criteria. Therefore the AER has adjusted forecast gross expenditure for these categories to be consistent with historical expenditure levels.

CitiPower and Powercor in their proposed forecast standard control capital expenditure included capital expenditure related to services including, customer supply negotiations, labour and materials for routine connections, meter installation costs and temporary supply services. CitiPower also proposed expenditure related to fault level mitigation for new embedded generators as part of standard control capital expenditure. These costs are proposed to be netted off by revenue received for the fault level mitigation compliance service.

The AER has not accepted the proposed classification of these services as standard control and has classified these services as alternative control as discussed in chapter 2. The AER has therefore removed the proposed gross capital expenditure and capital contributions for these services from the forecast new customer connections assessed as part of expenditure related to standard control services.

The AER notes that CitiPower’s and Powercor's proposed customer contributions used 2009 as a starting point to determine their forecast. Both DNSPs have proposed reduced customer contributions rates in their forecasts, based on changes to the marginal rate of reinforcement used in their calculations of customer contributions. This is based on the AER's recommendations on what it considers to be fair and reasonable incremental costs which are attributable to a customer for upstream augmentation in CitiPower's network.[36] However the basis of the reduction in forecast customer contributions proposed by CitiPower and Powercor was not clearly

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35 CitiPower, *Material program - CUB site: Customer Connection Augmentation*, February 2010, p. 3.

36 AER, *Benchmark Upstream Augmentation Charge Rates for CitiPower's Network - Draft Decision*, February 2010, p. 23.

supported in the information provided. The AER considers that given the X factor issue that customer contributions will need to be reassessed between the draft and final decision. For the draft decision the AER therefore adjusted CitiPower’s and Powercor's forecast customer contributions to be consistent with average customer contributions from 2006–09.

For the reasons discussed and based on the AER's analysis of the regulatory proposals, the AER is not satisfied that CitiPower’s and Powercor's new customer connection capital expenditure reasonably reflects the capex criteria including the capex objectives. In coming to this view the AER has had regard to the capex factors outlined in section 8.7.3. The AER considers that reducing CitiPower’s and Powercor's new customer connections gross capex forecasts to $197.5 million for CitiPower and $526.6 million for Powercor results in expenditure that reasonably reflects the capex criteria, 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.

The AER is not satisfied with the proposed net expenditure for CitiPower and Powercor, given that the current requirements of Guideline No. 14 have not been taken into account in the forecast calculation of customer contributions, as described above. Historical customer contributions levels for CitiPower and Powercor have been used as a place-holder in this draft decision, as this issue needs to be resolved between the draft and final decision.

Jemena

The AER in its assessment of Jemena's forecast customer contributions found that they were forecast to fall from an average 54 per cent in the current regulatory control period to 46 per cent in the forthcoming regulatory control period. Specifically, this proposal included a significant increase in net forecast expenditure for new customer connections, in the areas of business supply projects and special capital works. This issue was raised with Jemena.

Jemena in its response noted that its forecast of customer contributions was based on a fixed percentage of the average of three years of actual contributions. The AER considers this approach to be reasonable however the AER was concerned the historical data used by Jemena did not reconcile with the data provided in the RIN. Jemena noted that the data reconciling with the RIN was based on an allocation process used to determine the regulatory accounts, not actual data.[37]

The AER considers that it is reasonable to use consistent data to determine the forecast based on the average three years of actual data. It would be preferable to be using audited regulatory accounts data as the basis for historical expenditure, rather than unaudited data. However the AER considers that it is reasonable to use the actual data as the basis of its forecasts, rather than data based on an allocation process. The AER considers that this data should be verified by Jemena between the AER's draft and final decisions.

[37] Email from Jemena to the AER, Response to customer connections capex questions, 5 March 2010.

Jemena also proposed routine connections as a standard control service and included capital expenditure related to routine connections in the standard control forecast. This amount has been netted off by revenue from the forecast revenue from routine connections. The AER has not accepted this classification and has included it as an alternative control service—refer to the services classification chapter for further explanation of this draft decision. This has no net impact on forecast new connections capital expenditure for the forthcoming regulatory control period.

For the reasons discussed and based on the AER's analysis of forecast new customer connections capex, the AER is not satisfied that Jemena's new customer connection gross capital expenditure reasonably reflects the capex criteria including the capex objectives. The AER has amended Jemena's gross capital expenditure forecast to remove capex related to routine connections. In coming to this view the AER has had regard to the capex factors outlined in section 8.7.3.

The AER is not satisfied with the proposed net expenditure for Jemena, given that the current requirements of Guideline No. 14 have not been taken into account in the forecast calculation of customer contributions, as described above. Historical customer contributions levels for Jemena have been used as a place-holder in this draft decision, as this issue needs to be resolved between the draft and final decision. The AER has amended Jemena's customer contributions forecast to remove forecast contributions related to routine connections.

SP AusNet

The AER's initial assessment of SP AusNet's new customer connections sought further detail from SP AusNet on the basis of its forecast reduction in new customer contributions from historical levels of 29 per cent to a forecast level of 21 per cent of gross connections expenditure. During the review process, SP AusNet provided an update on its forecast of customer contributions, taking into account 2009 actual expenditure. Based on 2009 actual expenditure, SP AusNet revised its forecast customer contributions, to increase from an average 21 per cent to 29 per cent of gross new customer connections.[38] This results in net new customer connection forecast expenditure reducing from $268 million to $248 million over the forthcoming regulatory control period.

In its assessment of SP AusNet's proposed new customer connections, the AER also found that unit costs were trending upwards for low density housing in the forecast period, yet the historical data suggested units costs were trending downwards. It also sought further explanation for the basis of a forecast increase in unit costs for business supply projects. However, based on further information provided by SP AusNet and further assessment by the AER, the AER considered that average unit costs for these categories are consistent with historical trend.

Given SP AusNet's revised forecast of new customer connections and considering the average unit rates being reasonably consistent with historical trends, the AER is

[38] Email from SP AusNet to the AER, Response to customer connections capex questions, 19 February 2010, p. 3–4.

satisfied that SP AusNet's updated forecast new customer connections reflects the capex criteria to comply with the NER.

For the reasons discussed and based on the AER's analysis of SP AusNet's proposed new customer connections gross capital expenditure, and incorporating SP AusNet's revised forecast for customer contributions, the AER is satisfied that SP AusNet's gross new customer connections net capital expenditure reasonably reflects the efficient costs to achieve the capex objectives. It also reflects a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives. In coming to this view the AER has had regard to the capex factors outlined in section 8.7.3.

The AER is not satisfied with SP AusNet proposed net new customer connections expenditure, given that the current requirements of Guideline No. 14 have not been taken into account in the forecast calculation of customer contributions, as described above. Historical customer contributions levels for SP AusNet have been used as a place-holder in this draft decision, as this issue needs to be resolved between the draft and final decision.

United Energy

The AER in its assessment of United Energy's proposed net customer connections expenditure found that its forecast to decline by 9.6 per cent over the forthcoming regulatory control period, from and forecast increase in customer contributions from an average 35 per cent to 62 per cent.

The AER reviewed the breakdown of United Energy's forecast new customer connections, broken down by customer type. The AER found that its forecast gross expenditure broken down by unit costs and customer numbers are consistent with historical trend for each of United Energy's customer connection categories.

For these reasons and as a result of the AER's analysis, the AER is satisfied that United Energy's forecast gross new customer connections for the forthcoming regulatory control period reasonably reflects the efficient costs to achieve the capex objectives. It also reflects a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives. In coming to this view the AER has had regard to the capex factors outlined in section 8.7.3.

The AER is not satisfied with the proposed net expenditure for United Energy, given that the current requirements of Guideline No. 14 have not been taken into account in the forecast calculation of customer contributions, as described above. Historical customer contributions levels for United Energy have been used as a place-holder in this draft decision, as this issue needs to be resolved between the draft and final decision.

8.7.4 AER conclusion

Table 8.18 below sets out the AER's conclusion on the Victorian DNSPs' proposed capex for new customer connections, for the forthcoming regulatory control period. In reaching its conclusion the AER has, in accordance with the requirements of the NER, considered the information provided in the regulatory proposals and later material provided to clarify the interpretation of the proposals, submissions received, its own analysis and the actual and expected capex of the DNSP in the current regulatory control period. Although the AER also considered whether an appropriate benchmark could be established for this activity the AER found that insufficient data existed to set a reliable benchmark.

Within the approved total capex allowance, each DNSP retains discretion regarding the allocation and expenditure of capital. The AER expects each DNSP to be responsive to changing conditions in order to meet customer requirements while managing and operating the network in accordance with good electricity industry practice. If any matter arises which requires a DNSP to reorder its priorities then it is appropriate for the DNSP to do so within the total capex allowance. Basing forecast on historical trends should also mitigate concerns the previous forecasts bore little relation to actual expenditure.

Table 8.18 AER conclusion on new gross and net customer connections capex ($'m, 2010)

		2011	2012	2013	2014	2015	Total
CitiPower	Gross	39.6	39.6	39.5	39.4	39.5	197.5
	Net	17.9	17.8	17.8	17.8	17.8	89.0
Powercor	Gross	103.7	104.9	104.7	106.1	107.2	526.6
	Net	47.0	47.4	46.7	47.2	47.4	235.6
Jemena	Gross	22.9	23.8	24.6	26.2	28.0	125.6
	Net	12.4	13.1	13.6	14.4	15.2	68.7
SP AusNet	Gross	75.5	71.1	67.0	68.7	74.7	357.0
	Net	51.5	48.6	46.0	47.2	51.3	244.8
United Energy	Gross	42.2	41.9	43.6	43.7	43.0	214.4
	Net	19.5	19.0	19.3	18.2	17.5	93.5
Total	**Gross**	**283.9**	**281.3**	**279.5**	**284.1**	**292.4**	**1421.1**
	Net	**148.3**	**146.0**	**143.4**	**144.7**	**149.2**	**731.6**

Note: These draft decision capex amounts are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

8.8 Reinforcement

8.8.1 Introduction

DNSPs undertake reinforcement capital expenditure in order to meet the growing demand on the network. Reinforcement expenditure involves augmentation of network components to ensure they have sufficient capacity to meet high peak demand days. Reinforcement expenditure largely consists of augmentation of zone substations or establishing new zone substations, upgrading sub-transmission lines, 22kV distribution feeders and upgrading or establishing new distribution substations.

8.8.2 Approach

In assessing and determining whether each of the Victorian DNSPs' proposed reinforcement forecast capex reasonably reflects the capex criteria, the AER has had regard to the capex factors as relevant. In addition to capex factors 1, 2 and 3, the AER's analysis of forecast reinforcement expenditure capex takes into account:

- benchmark capex that would be incurred by an efficient DNSP over the regulatory control period.[39]

Appendix I to this draft decision (which should be read in conjunction with this chapter) sets out the AER's analysis which benchmarks the Victorian DNSPs against their interstate counterparts including benchmarking the DNSPs' forecasts against the AER's forecasts to assess the efficient level of reinforcement capex for the forthcoming regulatory control period.

- the actual and expected capex of the DNSP during any preceding regulatory control periods.[40]

The AER has compared the actual capex incurred during the current and previous regulatory control periods against the DNSPs' proposed capex and the AER's estimate of the required capex for the forthcoming regulatory control period taking into account any observed trends in actual capex.

- the extent the DNSP has considered, and made provision for, efficient non-network alternatives.[41]

The AER's review of reinforcement expenditure has assessed whether other non-network alternatives had been adequately considered in determining an efficient forecast of reinforcement capex.

Where the DNSPs' forecast reinforcement capex was significantly greater than actual capex incurred during the previous and current regulatory control periods, the AER also further investigated:

- the policies, procedures, and forecasting methodologies associated with the targeted matters
- whether there is a justifiable need for the proposed investment
- whether reasonable options were considered other than major augmentation (that is, deferrals) and the most efficient outcome selected to satisfy that need.

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[39] NER clause 6.5.7(e)(4).
[40] NER clause 6.5.7(e)(5).
[41] NER clause 6.5.7(e)(10).

In conducting the review of the Victorian DNSPs' forecast reinforcement capex allowance, the AER assumed the current level of capex to be a representation of an efficient base to forecast augmentation expenditure.

8.8.3 Victorian DNSP regulatory proposals

Each Victorian DNSP has proposed significant increases in reinforcement expenditure for the 2011–15 regulatory control period. Victorian DNSPs have argued the need for increased expenditure is to accommodate growth in the utilisation of the networks and growth in peak demand levels. Table 8.19 outlines the Victorian DNSPs' proposed reinforcement expenditure at a direct cost level, with total reinforcement forecast expenditure for all Victorian DNSPs to increase by 108 per cent from the current regulatory control period.

Table 8.19 Victorian DNSPs' proposed reinforcement capex ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	56.4	44.2	46.6	57.8	46.7	34.1	229.4	307
Powercor	121.4	43.9	44.8	49.2	53.0	50.7	241.5	99
Jemena	59.2	24.9	33.6	31.4	28.3	25.1	143.3	142
SP AusNet	164.7	56.6	71.1	62.4	66.6	64.5	321.2	95
United Energy	152.7	44.6	41.2	44.5	42.5	32.1	205.0	34
Total	**554.5**	**214.2**	**237.4**	**245.2**	**237.1**	**206.5**	**1140.4**	**106**

Note: Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1. Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, templates 2.1 and 3.1.

CitiPower

For the forthcoming regulatory control period, CitiPower proposed reinforcement expenditure of $229.4 million ($2010), a 307 per cent increase in expenditure from the current regulatory control period. CitiPower stated that there is a particular need to increase its reinforcement expenditure in the forthcoming regulatory control period to accommodate capacity growth after a period of increasing network utilisation and address new cost pressures and those associated with peak demand.[42]

Major reinforcement projects proposed by CitiPower include the continuation of work on the CBD security of supply and the Metro 2012, which includes upgrading the terminal station at Brunswick to a new 66kV connection point in order to relieve the loading on the CBD terminal stations, West Melbourne and Richmond. Other

42 CitiPower, *Regulatory Proposal*, November 2009, p. 87.

proposed reinforcement projects include the upgrade of the Docks area zone substation.

Powercor

Powercor has proposed an increase in reinforcement capital expenditure from $121.4 million to $241.5 million ($2010), a 99 per cent increase from the current regulatory control period. Powercor claim that this is due to continued growth in maximum demand and to maintain security standards for urban and rural zone substations.[43] Major projects included in Powercor's proposed expenditure include establishing new zone substations in Torquay and East Gisborne, increasing capacity of sub-transmission lines from the Geelong terminal station and from the Bendigo terminal station to the Charlton zone substation.

Jemena

Jemena has proposed reinforcement capital expenditure for the period to increase from $59.2 million ($2010) in the current regulatory control period to $143.3 million ($2010) for the 2011-2015 regulatory control period (a 142 per cent increase from the 2006–10 regulatory control period). Jemena stated in its regulatory proposal that its network initiated augmentation is driven by capacity development requirements and the forecast increase in customer load demand.[44] Major projects included in Jemena's proposed reinforcement expenditure include Preston/East Preston zone substation upgrade from 6.6kV to 22kV, new zone substations at Craigieburn, Tullamarine, Broadmeadows and Alphington, and a major distribution substation augmentation program.

SP AusNet

SP AusNet has forecast a program of $321.2 million ($2010) for augmentation works for the period. This is a 95 per cent increase ($164.7 million) from the current regulatory control period. SP AusNet has stated that this increase in the forthcoming regulatory control period is driven by peak demand growth, which is expected to continue at a rate of 4.4 per cent per year. Other reasons stated are growing and unsustainable levels of energy at risk and network utilisation, both of which require stabilisation.[45]

Major projects included in SP AusNet's reinforcement expenditure include new zone substations at Cranbourne, South Morang, Lakes Entrance, Mooroolbark and Wollert. SP AusNet's proposed reinforcement expenditure also includes significant increases in the augmentation of 66 kV lines and HV feeder upgrade programs during the forthcoming regulatory control period.

United Energy

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43 Powercor, *RegulatoryProposal*, November 2009, p. 77.

44 Jemena, *Regulatory Proposal: Appendix 10 – Jemena Electricity Networks (Vic) Ltd – Capital and Operational Work Plan (COWP) 2010–15* (Confidential), 30 November 2009, p. 15.

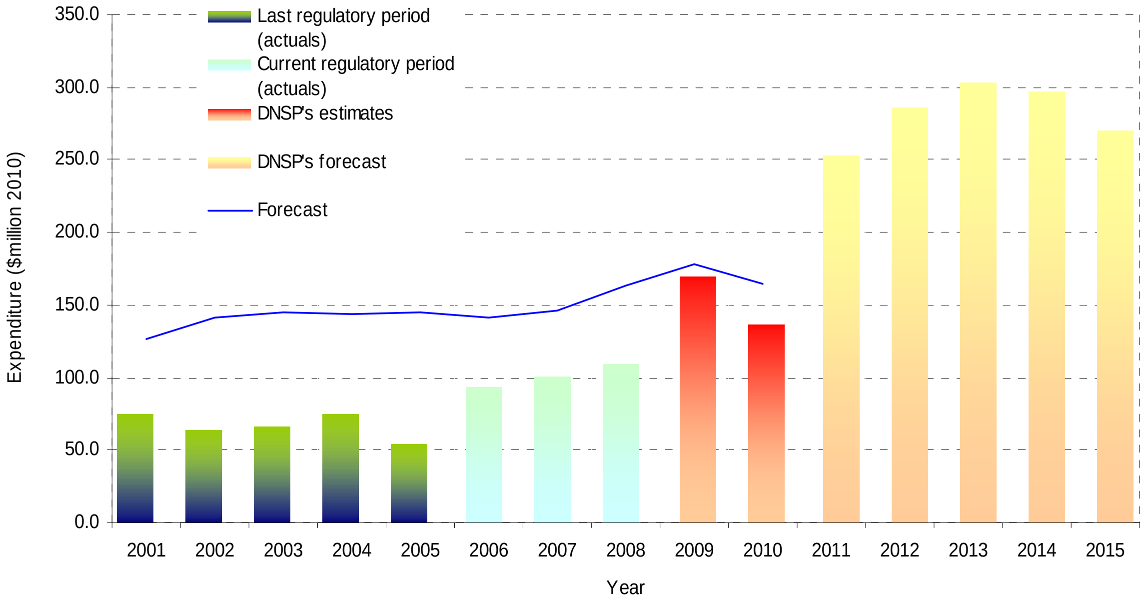
45 SP AusNet, *Regulatory Proposal*, November 2009, p. 122.

United Energy has proposed reinforcement expenditure of $205 million ($2010), which is a 34 per cent increase from the current regulatory control period. Major projects included new zone substations at Keysborough and Templestowe and the redevelopment and upgrade of Rosebud and Mornington zone substations.

8.8.4 Comparison of forecasts to current regulatory control period actual expenditure

Figure 8.2 compares the current regulatory control period actual expenditure with the proposed expenditure by the Victorian DNSPs, historically and for the forthcoming regulatory control period. The AER notes that in the current regulatory control period actual expenditure has been increasing consistently over the current and previous regulatory control periods for all Victorian DNSPs. However, the AER notes that previous DNSPs' capital expenditure proposals have been significantly higher than the actual expenditure incurred. Actual expenditure was approximately 50 per cent of the 2001 forecast for that period and in the current regulatory control period actual expenditure was only 67 per cent of the 2006 forecast for 2006–08.

Figure 8.2 Total reinforcement expenditure - all Victorian DNSPs



Note: The expenditure amounts in this figure are on a fully absorbed basis.

SP AusNet is the only DNSP that has incurred expenditure above the level it forecast for the current regulatory control period. In the case of SP AusNet, it considers that it had much higher demand growth and higher input costs than they anticipated at the time of 2006 EDPR proposal.[46]

46 SP AusNet, *Regulatory Proposal*, November 2009, p. 111.

8.8.5 Submissions on DNSP regulatory proposals

Origin in its submission was concerned with the relationship between peak demand, energy consumption and capex growth. It noted that assumptions about the relative changes in growth in volumes and peak demand have not been made sufficiently explicit, and it is not clear why the Victorian DNSP forecasts should differ from those in the Australian Energy Market Operator's Electricity Statement of Opportunities. Origin stated that if peak demand does grow as volumes drop this implies increases in capex are spread over fewer sales, which will result in persistent network price increases for customers.[47]

The AER considers that where possible DNSPs need to consider the potential for non-network solutions to address peak demand issues on the network. The AER has aimed to ensure that alternative non–network options have been considered as part of the economic analysis to determine an efficient forecast of reinforcement expenditure. The AER has also undertaken a thorough analysis of the proposed maximum demand and forecast energy sales—see chapter 5.

8.8.6 Consultant review

The AER engaged Nuttall Consulting to review each Victorian DNSPs' proposed reinforcement expenditure for the forthcoming regulatory control period. Nuttall Consulting undertook a high level review of the Victorian DNSPs' planning processes and methodologies used to determine their forecasts. It also undertook a more detailed analysis of specific projects for each business. In undertaking these two review processes Nuttall Consulting has made recommendations on the reasonableness of the proposed reinforcement expenditure forecasts for each Victorian DNSP.

Based on the findings from its methodological and detailed project reviews, Nuttall Consulting has determined an average weighted probability of the proposed reinforcement expenditure being required in the forthcoming regulatory control period for each DNSP. To determine its recommended level of reinforcement expenditure Nuttall Consulting has then applied this weighted probability to the DNSPs' proposed reinforcement expenditure.

Nuttall Consulting noted that the two key drivers for the proposed increases in reinforcement expenditure are growth in demand over the forthcoming regulatory control period and utilisation of existing assets. In relation to maximum demand growth, all Victorian DNSPs are forecasting significant levels of demand growth over the forthcoming regulatory control period, with SP AusNet forecasting significantly higher growth at 4.4 per cent per annum. At the same time, all Victorian DNSPs consider that the utilisation of their assets is high and has increased during the current regulatory control period.[48]

Nuttall Consulting also took into account the AER's review of the Victorian DNSPs' maximum demand forecasts in making its assessment of reinforcement expenditure, due to the potential impact on the timing of augmentations that would result from

47 Origin Energy, *Submission to the AER Review of Victorian Electricity DNSPs regulatory proposals*, February 2010,pp. 2–3.
48 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 46.

revised maximum demand forecasts. Given the probabilistic approach taken in making its recommendation, Nuttall Consulting has allowed for the general findings in determining the likelihood of projects occurring as planned.

Methodological Review

A key component of Nuttall Consulting's review of reinforcement expenditure was to assess the appropriateness of the methodologies used to determine each DNSP's reinforcement expenditure forecast. The following outlines Nuttall Consulting's review of the key methodologies used by the Victorian DNSPs to determine their reinforcement expenditure forecasts. This methodological review sought to inform its more detailed project review and its final assessment of the reasonableness of the Victorian DNSPs' proposed forecasts.

In its review of each DNSP's methodologies used to determine forecasts for sub-transmission lines and zone substation augmentations, Nuttall Consulting found that all Victorian DNSPs have undertaken a bottom up build of their forecasts, with projects forecast being determined using a probabilistic approach. This approach weighs the forecast value of the expected energy at risk to customers against the costs to reduce the energy at risk.[49]

Nuttall Consulting found that the Victorian DNSPs have differed in the approach used. Specifically, it found that only SP AusNet had rigorously applied detailed probabilistic planning to the development of its reinforcement plans. Jemena and United Energy on the other hand indicate that full probabilistic analysis is undertaken. However, these assessments have not been undertaken for many projects, and it appears that engineering judgement has been used to determine project timings in these cases. Alternatively CitiPower and Powercor determine investment using internal planning criteria to simplify the planning analysis, rather than a full probabilistic assessment. Nuttall Consulting considers that this criteria is generally conservative, and would essentially advance projects from their optimal economic time.[50]

In terms of the scope and timing of a project known issues may be taken into account by a DNSP, including matters such as age, condition, or physical circumstances of the existing assets and arrangements. The AER notes that the basis of this timing of major projects was heavily reliant on the judgement of planning engineers. The manner in which this judgement is exercised was not clearly set out in most Victorian DNSPs' regulatory proposals. The AER further notes that forecast projects are subject to significant change in scope and timing when each DNSP conducts a more thorough analysis later in the business/planning cycle.

A key input into the energy at risk calculations used to determine the timing of augmentations is the load duration curve. The shape of the load duration curve can impact on the amount of energy at risk used to justify an augmentation. As the load profile becomes peakier, the energy at risk will reduce whereas, if a calculation is made on the basis of a flatter profile then the apparent energy at risk will increase.

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49 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 49.
50 ibid., p. 52.

The Victorian DNSPs have generally forecast a combination of increased maximum demand and lower energy sales in the forthcoming regulatory control period. Nuttall Consulting considers that this change in the load profile reduces the energy at risk that DNSPs should be using to justify augmentation. However, Nuttall Consulting found that some Victorian DNSPs had used old, flatter load profiles to predict energy at risk. Nuttall Consulting considered that this may overstate the level energy at risk as load profiles have changed significantly, due to maximum demand growing at a higher rate than energy over the last 10 years. Furthermore, given that this is predicted to continue, Nuttall Consulting considered that for the DNSPs that use older load profiles to predict energy at risk this problem of over-forecasting would be further compounded. Nuttall Consulting therefore considered that this may result in projects being advanced by periods from one to three years depending on the discrepancy in the load growth forecast.[51]

Another key element in the determining energy at risk assessed by Nuttall Consulting is the weather condition assumptions made in determining forecast maximum demand. Nuttall Consulting's assessment noted that four of the Victorian DNSPs—CitiPower, Powercor, Jemena and SP AusNet—based their maximum demand forecasts on a 50 per cent probability of exceedence (PoE). This translates to maximum demand forecasts being based on a probability of exceeding one in two year weather conditions. United Energy used a more conservative approach of a 10 per cent PoE, which is basing maximum demand forecasts on a probability of exceeding one in 10 year temperatures. This therefore assumes higher forecast temperatures compared with the other DNSPs and higher forecast maximum demand. Nuttall Consulting considered that for United Energy this may considerably overstate the forecast of energy at risk, resulting in projects being advanced by one to three years depending on the load growth.[52]

Nuttall Consulting also assessed the probability of failure of transformers used by the DNSPs to determine their energy at risk calculations. Nuttall Consulting noted that DNSPs used a one in 100 year catastrophic failure rate with a two to three month outage time. Nuttall Consulting considered that although the outage rates applied are consistent with industry standards, there is some discretion that the DNSP could apply. Specifically with outage time, Nuttall Consulting considered that there is scope for this to be reduced via optimisation of spares and contracting arrangements with transformer manufacturers.[53]

With regard to the methodologies used to forecast distribution substation expenditure, Nuttall Consulting assessed the methodologies proposed by Jemena, United Energy and SP AusNet in developing a pro-active approach to replacing distribution transformers. The proposed approach estimates the maximum demand of the transformer population, based on customer types and metering information. The number of transformers requiring upgrading is then determined based upon the quantity with a predicted maximum demand above the maximum transformer rating.[54] The AER notes that CitiPower and Powercor have not proposed proactive programs,

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[51] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 52–53.
[52] ibid., p. 53.
[53] ibid.
[54] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 54.

and have proposed forecasts at the distribution substation level more consistent with the historical trend.

Overall, Nuttall Consulting considered that the methodologies used for developing internal capital plans are reasonable for developing a comprehensive list of projects that can be monitored and developed further.[55]

However, Nuttall Consulting does not consider that the largely bottom up based process that each of the DNSPs have applied is 'fit for purpose' in terms of being a reasonable unbiased estimator for the future prudent and efficient expenditure at the aggregate level. In particular, Nuttall Consulting does not consider that such a process adequately allows for further optimisation of projects and synergies between projects that will occur as the individual projects and the overall capital plans advance through the capital governance process.[56]

Nuttall Consulting does note that in some circumstances these processes will result in some projects being advanced or their scope increased. However, Nuttall Consulting considers that more detailed evaluation and justification associated with the approval processes will most likely result in overall expenditure being less than the simple summation of total projects planned.[57]

These key methodological issues associated with the DNSP's reinforcement expenditure forecasts were considered further by Nuttall Consulting in its more detailed project reviews outlined in the next section.

Detailed project review

Nuttall Consulting undertook a detailed review of major reinforcement projects proposed by each Victorian DNSP. This detailed review included an end–to–end review of the costs, timing and deliverability of the major projects proposed by each DNSP.

The overall aim of the project reviews has been to determine the likelihood that the project expenditure will be required as proposed by the DNSPs. The AER and Nuttall Consulting considered that this is a reasonable approach to account for the likely consequences of the governance processes and the other specific methodological concerns with the reinforcement expenditure forecasts as discussed above.

Based on this assessment, Nuttall Consulting has assigned to each project a low, moderate, or high probability that the expenditure will be required in the forthcoming regulatory control period, and with the proposed timing. Combining the results from its methodological review and detailed project review, Nuttall Consulting has determined a weighted aggregate probability for the total proposed reinforcement expenditure being required. Nuttall Consulting has recommended applying this weighted probability to determine a revised reinforcement expenditure forecast for each DNSP.

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[55] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 51.
[56] Ibid., p. 51.
[57] ibid., p. 51–52.

The following outlines Nuttall Consulting's key findings from its project review for each Victorian DNSP and its overall recommendation for forecast reinforcement expenditure.

CitiPower

Nuttall Consulting undertook a detailed project review for CitiPower which included an assessment of the CBD security of supply and the Metro 2012 projects. These projects largely involve proposed upgrading the terminal station at Brunswick to a new 66kV connection point in order to relieve two CBD terminal stations, West Melbourne and Richmond. Other projects assessed included the proposed upgrade of the Docks area zone substation and HV feeder works in the CBD area.

The table below outlines Nuttall Consulting's recommendations on each of the detailed projects reviewed for CitiPower.

Table 8.20 CitiPower augmentation projects reviewed by Nuttall Consulting

Project reviewed	Nuttall Consulting assessment	Nuttall Consulting recommendation of probability of project being required
CBD Security of supply	Increase in costs above that included in the original regulatory test has not been justified. It is recommended to base forecast on costs included in original regulatory test.	Not applicable.
Metro 2012	Increase in costs above that included in the original regulatory test has not been justified. It is recommended to base forecast on costs included in original regulatory test.	Not applicable.
11 kV Feeder works	Half the works appear to be security related and the other half are capacity related. However the energy at risk does not support cost of project going ahead.	Low probability of being required.
3rd Transformer at BQ zone substation	The cost of energy at risk does not appear to justify project and other alternative options have not been sufficiently considered.	Low probability of being required.
3rd Transformer at SB zone substation	The energy at risk does not justify the project. Alternative options have also not been considered in sufficient detail.	Low probability of being required.
Docks area zone substation upgrade	Given its concerns regarding the load profile assumed, Nuttall Consulting considered that the proposed project should be deferred. It also considered that there may be lower cost options that may be justified through more detailed analysis.	Moderate probability of being required.

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp.96-100.

Overall findings

Based on its review, Nuttall Consulting considered that CitiPower has not adequately demonstrated that its proposed increase in reinforcement expenditure is reasonable. It considered that a reasonable estimate would be more in line with historical trend.[58]

This is based on a number of findings. Firstly, in relation to its findings from its methodological review, Nuttall Consulting considered that CitiPower's approach is reasonable for developing internal capital plans. However, it does not consider that this largely bottom up based process has been shown to be a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level.[59]

Nuttall Consulting also had a number of concerns with key input assumptions used by CitiPower for its forecasts. Specifically it considered that the average load profile from 2001–05 used by CitiPower may overstate risks and could result in projects

58 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 100.
59 ibid., p. 94.

being advanced by up to three years. Further, Nuttall Consulting considered that the internal planning criteria assumed by CitiPower, does not adequately demonstrate how the economic benefits through the reduction in the energy at risk outweigh the cost of the projects forecast.[60] These key methodological issues were further supported by its detailed project review.

For the specific projects reviewed, generally Nuttall Consulting considered that the timing did not appear to be economically justified, in terms of the benefits through the reduction in the energy at risk. Only one project reviewed, the Docks Area zone substation upgrade, which was planned for 2014, if undertaken with the proposed timing would result in only a small benefit. However given its concerns with CitiPower's load profile and the forecast of peakier loads for the forthcoming regulatory control period, Nuttall Consulting considered that there is a reasonable possibility that this project will be deferred.[61]

Nuttall Consulting considered that in many cases there appears to be potential for other lower cost options to be developed but this potential has not been considered by CitiPower. Nuttall Consulting considered that a more thorough economic evaluation may determine that the deferral of a project or a lower cost infrastructure alternative as being the most efficient option. Nuttall Consulting also considered that the AER's review of CitiPower's maximum demand forecast also supports the view that many projects may be optimally deferred, particularly those towards the end of the period.[62]

In relation to the CBD security of supply and Metro 2012 projects, Nuttall Consulting's detailed project review, found that these projects had been through a regulatory test and were subject to a detailed review by the ESCV. However Nuttall Consulting considered that CitiPower has not adequately demonstrated the basis of the proposed additional expenditure included in the forecasts. Therefore it recommends the cost estimates that formed part of the original regulatory test are included in the forecasts with adjustments for cost escalations.[63]

Nuttall Consulting also considered that for other projects of, such as elements of the HV feeder projects, the main need appears to be the increased security of supply. However they do not form part of the original regulatory test for the CBD security of supply and on their own they do not appear to be economically justified.

Based on Nuttall Consulting's methodological and detailed project review and the issues found with CitiPower's proposed forecast as described above, it considered that there is a low probability (39 per cent)[64] that the reinforcement expenditure, excluding CBD Security of Supply and Metro 2012, would be required as proposed by CitiPower in the forthcoming regulatory control period.[65]

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60 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 95.
61 ibid., p. 101.
62 ibid., p. 101.
63 ibid., p. 101.
64 This has been calculated in accordance with Nuttall's weighted average probability methodology.
65 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 101.

Powercor

Nuttall Consulting undertook a detailed review of Powercor's proposed new zone substation at Gisborne, augmentation at the Eaglehawk zone substation, augmentation of the Charlton to Bendigo sub-transmission lines, upgrade of transformers at East Geelong, and an upgrade of 66V lines at the Geelong terminal station.

The following table outlines the outcomes of Nuttall Consulting's detailed review of the identified Powercor's augmentation projects.

Table 8.21 Powercor augmentation projects reviewed by Nuttall Consulting

Project reviewed	Nuttall Consulting assessment	Nuttall Consulting recommendation of probability of project being required
Eaglehawk augmentation	Nuttall Consulting considered that this project was economically justified and alternative options have been adequately considered.	High probability being required.
Gisborne new zone substation	The planned augmentation works does not economically justify the proposed timing of the project. The AER’s revised maximum demand forecasts at the Woodend zone substation further support the deferral of this project.	Low to moderate probability of being required.
Augmentation of Charlton to Bendigo sub–transmission line	Nuttall Consulting found other options including deferral of some stages may be found to be optimal with further economic analysis.	Low to moderate probability of being required.
Geelong East transformer	The energy at risk calculations suggest the timing is justified, however this does not appear to account for transfers.	Moderate probability of project being required.
Geelong sub–transmission lines upgrade	The energy at risk appears to justify the timing, however the regulatory test undertaken for this project does not cover all the works proposed by Powercor.	A moderate to high probability of project being required.
Cobram East - Numurkah 66 kV line upgrade	Load for this line will be high and some augmentation will be required. However Powercor has not clearly demonstrated that the energy at risk is sufficient to justify the proposed project.	A moderate to high probability of project being required.

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp.178-181.

Overall findings

Based on its review, Nuttall Consulting considered that Powercor has not adequately demonstrated that its proposed increase in reinforcement expenditure is reasonable. It considered that a reasonable estimate would be more in line with historical trend.[66]

This is based on a number of findings. Firstly, in relation to its findings from its methodological review, Nuttall Consulting considered that Powercor's approach is reasonable for developing internal capital plans. However, it does not consider that this largely bottom up based process has been shown to be a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level.[67]

In relation to its forecasting methodology, Nuttall Consulting also had a number of concerns with key input assumptions used by Powercor. Specifically it considered that the load profile from 2009 used by Powercor may overstate risks due to the number of extended periods of high temperature. Nuttall Consulting considered that applying a load profile that is more representative of 50 per cent PoE conditions may result in projects being deferred by up to three years. Further, Nuttall Consulting considers that the internal planning criteria assumed by Powercor, does not demonstrate how the economic benefits through the reduction in the energy at risk outweigh the cost of the projects forecast.[68] These key methodological issues were further supported by its detailed project review.

In its assessment of Powercor's major augmentation projects, Nuttall Consulting generally found that the timing of the projects reviewed were justified by the benefits due to reducing energy at risk at the specified zone substations. In some cases Nuttall Consulting considered that low cost options that have not been considered in detail by Powercor. Nuttall Consulting considers that upon further economic analysis, staging/deferring of a project or a lower cost alternative infrastructure may be revealed to be the most efficient option.[69]

Nuttall Consulting also considered that the AER's recommended reductions to Powercor's maximum demand forecasts, provides further justification for the deferral a number of augmentation projects.[70]

Therefore based on its methodological and detailed projects reviews and the issues found with Powercor's proposed reinforcement expenditure as described above, Nuttall Consulting considers that there is a moderate probability (62 per cent)[71] of the total forecast reinforcement expenditure proposed by Powercor being required in the forthcoming regulatory control period.[72]

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66 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 182.
67 ibid., p. 177.
68 ibid., p. 177.
69 ibid., p. 182.
70 ibid., p. 182.
71 This has been calculated in accordance with Nuttall's weighted average probability methodology.
72 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 182.

Jemena

Nuttall Consulting as part of its review selected a sample of Jemena's major reinforcement projects. Major sub-transmission projects reviewed include the East Preston and Preston zone substation upgrade, new zone substations at Craigieburn and Tullamarine, and various sub–transmission loops. Nuttall Consulting also undertook a review of the proposed distribution substation transformers.

Nuttall Consulting's key findings of its detailed project reviews are outlined in the table below.

Table 8.22 Jemena augmentation projects reviewed by Nuttall Consulting

Project reviewed	Nuttall Consulting assessment	Nuttall Consulting recommendation of probability of project being required
Preston/ East Preston conversion	This project is mainly age driven, but it does not appear that assets require replacement at the proposed time. Further analysis will result in a more optimal timing and likely deferral of some elements.	A low to moderate probability of being required.
Pascoe Vale transformer upgrade	The load at risk is not sufficient to justify this project. There is also not sufficient evidence to suggest that alternatives have been fully considered.	Moderate probability of project being required.
Tullamarine new zone substation	There is not a clear demonstration that energy at risk is sufficient to justify the timing of the project.	Moderate probability of being required.
Craigieburn new zone substation	The cost of energy at risk does not justify the project, and other lower cost options have not been considered. The AER’s revised maximum demand forecast at the Somerton zone substation further support project deferral.	Low probability of being required.
TTS-CN-CS-TTS 66 kv line	The cost of energy at risk appears to justify project and the alternative options have been reasonably considered.	High probability of being required.
KTS-MAT-AW-PV-KTS 66kv loop	The cost of energy at risk indicates the project should be deferred by 1 to 2 years.	Low probability of project being required.
Distribution transformer program	It is unclear how effective the transformer replacement program will be effective in reducing failure rates. A low probability has been applied to allow for existing levels of upgrades, with some allowance for escalation in volumes.	Low probability of being required.

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp.141-145.

Overall Findings

Based on its review, Nuttall Consulting considered that Jemena has not adequately demonstrated that its proposed increase in reinforcement expenditure is reasonable. It considered that a reasonable estimate would be more in line with historical trend.[73]

This is based on a number of findings. Firstly, in relation to its findings from its methodological review, Nuttall Consulting considered that Jemena's approach is reasonable for developing internal capital plans. However, it does not consider that this largely bottom up based process has been shown to be a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level.[74]

Nuttall Consulting also had significant concerns with Jemena's key input assumptions used in its forecasting methodology. Specifically, it was concerned with its approach to assessing load at risk, where in the forthcoming regulatory control period Jemena assumes a load profile based upon demand in 1999–2000. Nuttall Consulting's analysis suggested that this may overstate the energy at risk prediction in the forthcoming regulatory control period, due to the 'peakier' nature of the load profile that has occurred since that time (this is driven by the higher maximum demand growth compared to energy growth that has occurred since that time, and is forecast to continue). Nuttall Consulting therefore considered that this may result in projects beings deferred by up to three years depending on the associated load growth.[75]

From its detailed project reviews, Nuttall Consulting considered that for some of the projects such as the Preston voltage upgrade and Pascoe Vale upgrade, the driver of the timing of the projects was the age/condition of existing assets. Without this issue, Nuttall Consulting considered that the energy at risk and capacity issues would not require the augmentation at the proposed time.[76]

In many cases, Nuttall Consulting considered that the projects reviewed did not appear to be economically justified, in terms of benefits from reducing the energy at risk. Further, Nuttall Consulting also considers there to be other lower cost options, not considered in detail by Jemena. Nuttall Consulting considers that a more thorough economic evaluation may lead to staging and/or deferral of projects or a lower cost alternative infrastructure as being the preferred option.[77]

With regard to the distribution transformer upgrade program, as outlined above Nuttall Consulting questioned whether moving from a reactive approach to a proactive approach would lead to reduced failures of distribution substations due to the inability to predict transformer failure. Nuttall Consulting considers that it cannot be concluded that a more proactive approach will be more prudent and effective at this stage.[78]

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73 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 145.
74 ibid., p. 140.
75 ibid., pp. 140–141.
76 ibid., p. 146.
77 ibid., p. 146.
78 ibid., p. 146.

Based on its methodological and detail project review, and the issues identified Jemena's proposed reinforcement expenditure, as described above, Nuttall Consulting considered that there is a moderate probability that the reinforcement expenditure would be required as proposed by Jemena. Therefore based on Nuttall Consulting has recommended that there is a low probability (38 per cent)[79] of the total forecast reinforcement expenditure proposed by Jemena as being required in the forthcoming regulatory control period.[80]

SP AusNet

Nuttall Consulting's detailed project review for SP AusNet included an assessment of proposed new 66/22kV zone substations at Mooroolbark and Wollert in order to address excessive loading and load at risk at respective surrounding zone substations. Other proposed projects assessed by Nuttall Consulting also included the establishment of a second 66kV line between the Kilmore South and Seymour zone substations to address voltage stability limitation on the 66kV sub-transmission loop under the loss of the existing line between Kilmore South and Seymour.

The table below outlines the Nuttall Consulting's recommendations on each of the detailed projects reviewed for SP AusNet.

[79] This has been calculated in accordance with Nuttall's weighted average methodology.
[80] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 146.

Table 8.23 SP AusNet augmentation projects reviewed by Nuttall Consulting

Project reviewed	Nuttall Consulting assessment	Nuttall Consulting recommendation of probability of project being required
Mooroolbark Zone Substation	SP AusNet's energy at risk and loss reduction calculations supports the timing of this project. However a more extensive economic analysis of issues may result in the project scope and timing being optimised further. The AER's revised maximum demand forecasts resulted in a lower demand growth at one of the contributing substations impacting on its load at risk profile.	Moderate to low probability of being required.
Wollert Zone Substation	SP AusNet's energy at risk calculations support the cost of the project going ahead. Alternative options appear to have been adequately considered.	High probability of being required.
2nd 66 kV line from Kilmore South and Seymour Zone Substations	SP AusNet's energy at risk and loss reduction calculations supports the timing of this project. A more extensive economic analysis of issues may result in the project scope and timing being optimised further. Energy at risk based on historical outage probability appears high. Outage probability requires further justification and options assessment should consider options to improve the probability.	Moderate to low probability of being required.
Zone substation transformer upgrade program	Based on a review of a sample of zone substation transformers, the overall energy at risk does appear to justify the timing of these projects. A more extensive economic analysis of issues may result in the project scope and timing being optimised further. A more extensive economic analysis of management of spares may also result in some deferral. The AER revised maximum demand forecasts also support the deferral of zone substation augmentations.	Moderate probability of project being required
Distribution transformer upgrade program	It is unclear how effective the transformer replacement program will be effective in reducing failure rates. A moderate probability as been applied based to allow for existing levels of upgrades, with some allowance for escalation in volumes.	Moderate probability of project being required.

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp.217-221.

Overall findings

Based on its review, Nuttall Consulting considered that SP AusNet has not adequately demonstrated that its proposed increase in reinforcement expenditure is reasonable. It considered that a reasonable estimate would be more in line with historical trend.[81]

This is based on a number of findings. Firstly, in relation to its findings from its methodological review, Nuttall Consulting considered that SP AusNet's approach is reasonable for developing internal capital plans. However, it does not consider that

81 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 226.

this largely bottom up based process has been shown to be a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level.[82]

Nuttall Consulting also had significant concerns with SP AusNet's key input assumptions used in its forecasting methodology. Specifically, it was concerned with its approach to assessing load at risk, where in the forthcoming regulatory control period SP AusNet assumes a load profile based upon demand in 2007–08. Nuttall Consulting's analysis suggested that this may overstate the risks, particularly in the latter half of the forthcoming regulatory period, and may result in the deferment of some projects.[83]

Based on its detailed project review, Nuttall Consulting noted that whilst the overall timing of SP AusNet's proposed projects can be justified in terms of benefits due to reducing the expected energy not supplied, it considered that in some cases projects or parts of projects could be deferred or that the benefits from the projects were marginal.[84]

In regard to timing of the proposed projects, Nuttall Consulting noted that several factors could see a delay for a number of projects. Firstly, Nuttall Consulting noted that some projects may be deferred by a year or two as SP AusNet did not allow for potential load transfer. Also, given the view that the demand profile will become peakier through the forthcoming regulatory control period, there is a reasonable assumption that some projects will be deferred particularly near the end of the forthcoming regulatory control period. Finally, with regard to the transformer upgrades, Nuttall Consulting considered that a more effective use of spares for transformers may allow some of the risks involved with transformer failures to be reduced, resulting in deferral of some of these projects.[85]

Nuttall Consulting also noted that some of the large projects have been proposed to address a number of issues. Due to the provision of limited detailed economic analysis of these projects, Nuttall Consulting noted that there is a reasonable potential that either staging/deferral of the project or a lower cost option may be the preferred option. However, this potential would only come to light through further robust analysis of more detailed project material.[86]

Finally, Nuttall Consulting considered that SP AusNet has not adequately demonstrated that the pro-active distribution transformer upgrade program will realise the benefits that are predicted.[87]

Therefore based on its methodological and detailed project reviews, and the issues it has identified with SP AusNet's proposed reinforcement expenditure, as described above, Nuttall Consulting considered that there is a moderate probability

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82 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 221.
83 ibid, p. 222.
84 ibid., p. 226.
85 ibid.
86 ibid.
87 ibid.

(53 per cent)[88] that the reinforcement expenditure would be required as proposed by SP AusNet.[89]

United Energy

Nuttall Consulting undertook a detailed review of a sample of United Energy's major augmentation projects. These projects included new zone substations at Keysborough and Templestowe, a proposed third transformer at Mentone, upgrade works at Mornington and Rosebud zone substations. It also undertook a review of United Energy's proposed distribution substation program.

The following table outline Nuttall Consulting's key findings in relation to the detailed project reviews it undertook.

88 This has been calculated in accordance with Nuttall's weighted average methodology.
89 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 226.

Table 8.24 United Energy augmentation projects reviewed by Nuttall Consulting

Project reviewed	Nuttall Consulting assessment	Nuttall Consulting recommendation of probability of project being required
Templestowe - new zone substation	The energy at risk does not justify the project until after the forthcoming regulatory control period.	Low probability of being required.
Keysborough - new zone substation	The energy at risk calculations indicate that this project is justified. However there is some potential for further optimising the scope and timing for project.	Moderate to high probability of being required.
Mentone - transformer augmentation	Cost of energy at risk is sufficient to justify project. Other interim options of 22 kV line much lower cost may be justified	A high probability of being required
Malvern to Burwood sub-transmission 66 kV lines	There is no energy at risk does justify this project in the forthcoming regulatory control period. There is also a possibility of transformer replacements at Burwood being deferred, resulting in the deferral of the line upgrade.	Moderate probability of being required.
Tyabb - Dromana - Rosebud - Sorrento 66 kV lines	The energy at risk calculations does not support the timing of the project. Reasonable possibility that the project will be deferred or work required will be reduced in scale.	Moderate probability of being required.
Distribution transformer program	It is unclear how effective the transformer replacement program will be in reducing failure rates. A moderate probability has been applied based to allow for existing levels of upgrades, with some allowance for escalation in volumes.	Moderate probability of being required

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp.256-259.

Overall findings

Based on its review, Nuttall Consulting considered that United Energy has not adequately demonstrated that its proposed increase in reinforcement expenditure is reasonable. It considered that a reasonable estimate would be more in line with historical trend.[90]

This is based on a number of findings. Firstly, in relation to its findings from its methodological review, Nuttall Consulting considered that United Energy's approach is reasonable for developing internal capital plans. However, it does not consider that this largely bottom up based process has been shown to be a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level.[91]

As outlined in the table above, in many cases Nuttall Consulting's review found that the timing of United Energy's projects did not appear to be economically justified, or the benefits through the reduction in energy at risk were marginal. Given its use of conservative 10 per cent PoE weather conditions as the basis for its maximum demand forecasts, Nuttall Consulting considered that many of the proposed projects could be deferred by up to three years depending on the load growth.[92]

In many cases, Nuttall Consulting considered that the projects reviewed did not appear to be economically justified, in terms of benefits from reducing the energy at risk. Further, Nuttall Consulting also considered there to be other lower cost options, not considered in detail by United Energy. Nuttall Consulting considers that a more thorough economic evaluation may lead to staging and/or deferral of projects or a lower cost alternative infrastructure being the preferred option.[93]

For other projects, Nuttall Consulting found that the proposed timing was due to the age and condition of the assets. Without this issue, it appeared that the cost of energy at risk did not justify the proposed timing.[94]

With regard to the distribution transformer upgrade program, Nuttall Consulting considered that United Energy has not adequately demonstrated the pro-active upgrade program will realise the benefits that have been predicted. It also considered that many of the most faulty distribution transformers would have been replaced after the summer 2009 which incurred 1 in 50 year weather conditions.[95]

Based upon its methodological and detailed project reviews, and the issues identified with United Energy's proposed forecast, as described above, Nuttall Consulting considered that there is a moderate probability (63 per cent)[96], that the reinforcement expenditure would be required as proposed by United Energy in the forthcoming regulatory control period.[97]

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90 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 259.
91 ibid., p. 255.
92 ibid., p. 255.
93 ibid., p. 260.
94 ibid., p. 260.
95 ibid., p. 259.
96 This has been calculated in accordance with Nuttall's weighted average methodology.
97 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 260.

Overall review findings for all DNSPs

Based on its methodological and detailed project reviews, Nuttall Consulting considered that each of the Victorian DNSPs have not demonstrated that their proposed reinforcement expenditure reasonably represents a prudent and efficient allowance. Based on its findings, it considered that significant reductions to the proposed plans is likely to occur as the plans pass through the governance processes and more detailed evaluation and justification is undertaken.[98]

Specifically, for many of the projects reviewed, Nuttall Consulting's analysis of the benefits through the reduction in energy at risk did not justify the project at the proposed timing, or it did not consider benefits to be significant. Given some of the conservative input assumptions used, Nuttall Consulting considered that the optimal timing for many projects will be deferred by one to three years from the times proposed by the Victorian DNSPs.[99]

Nuttall Consulting also considered that in many cases, alternative lower cost options, such as the deferral and/or staging of projects, or lower cost infrastructure, may be the preferred option following the more rigorous evaluation that will occur as projects are evaluated, justified and approved within the capital governance processes.[100]

With regard to the distribution transformer upgrade program proposed by Jemena, United Energy and SP AusNet, Nuttall Consulting did not consider that they have adequately demonstrated that the pro-active upgrade program will realise the benefits that are predicted. In particular, Nuttall Consulting did not consider that the DNSPs have provided sufficient evidence to show that the proposed methodologies can adequately target the transformers, such that it will reduce the transformer failure rate sufficiently. Nuttall Consulting also considered that a delay until the AMI roll-out may allow information from these meters to be used to assist in better targeting.[101]

Nuttall Consulting considered that based on this overall assessment actual reinforcement expenditure will be far more in line with the historical trend. Therefore as outlined above, Nuttall Consulting considered that applying its recommended probability to the proposed reinforcement expenditure, based on its methodological and detailed project reviews, provides a reasonable forecast level of reinforcement expenditure for each DNSP.

To profile the revised expenditure for each DNSP based on its recommended aggregate probability, Nuttall Consulting has recommended using the average actual expenditure in the 2006 to 2008 period as a starting point for the expenditure profile. Nuttall Consulting has then applied an annual growth rate to profile the recommended revised forecast reinforcement expenditure, based on the aggregated probability determined for each DNSP.[102]

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98 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 54.
99 ibid..
100 ibid, p. 53.
101 ibid, p. 54.
102 ibid.

8.8.7 AER considerations

The AER reviewed each Victorian DNSP's augmentation capex proposals for the forthcoming regulatory control period. The AER considered the documentation provided by the Victorian DNSPs in support of their regulatory proposals, and has considered the detailed technical assessment from Nuttall Consulting, as outlined in the previous section, about the prudency and efficiency of the proposed reinforcement expenditure.

The AER in its review had concerns with the significant increases in expenditure forecast by each DNSP for the forthcoming regulatory control period, and the lack of supporting documentation to justify the proposed increased expenditure. This being that the RIN template requested information based on the categories included in the ESCV's regulatory accounts. However, the information relating to reinforcement expenditure did not allow for detailed assessment of the proposed forecast reinforcement capex. Given the significant increases, the AER requested that the Victorian DNSPs provide historical and forecast expenditure provided in the RIN template broken down by:

- sub-transmission—zone substations, circuits
- distribution—feeders, transformers.

This information was required to gain a further understanding of the expenditure included in the RIN, and to identify where certain elements of reinforcement expenditure were being forecast to increase significantly from the current regulatory control period, which was not clear from the Victorian DNSPs' regulatory proposals. This enabled the AER and Nuttall Consulting to focus its review on those areas where the significant increases of reinforcement capex were forecast in the DNSPs' proposals. Specifically, while all DNSPs had proposed significant increases in expenditure at the zone substation level it also revealed the significant increase in Jemena, SP AusNet and United Energy's proposed expenditure in distribution substations, which was not clear from the initial regulatory proposals.

In its assessment of reinforcement expenditure the AER also sought advice from ACIL Tasman on the reasonableness of the DNSPs' proposed maximum demand forecasts that form the basis of the proposed zone substation augmentations. ACIL Tasman's assessment considered that each DNSP had over forecast their maximum demand, and recommended that maximum demand zone substation forecasts be reduced to reconcile with the maximum demand forecast made by NIEIR, subject to some adjustments.[103] The AER considers that established zone substations that have forecast growth 1.5 per cent above the average for all zone substations, as well as those where forecast growth is 1.0 per cent above its historic average rate of growth, should be targeted for reduction—refer to chapter 5. The AER's conclusion on maximum demand forecasts further supports Nuttall Consulting's recommendations to defer a number of the DNSPs' proposed reinforcement projects.

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[103] ACIL Tasman, *Victorian Electricity Distribution Price Review—Review of maximum demand forecasts*, Report prepared for the AER, 19 April 2010.

With regard to the methodology used by the Victorian DNSPs to determine their forecasts, the AER found that in many cases the basis of this timing of major projects was based not just on the cost of energy at risk but a number of factors, and was heavily reliant on the judgement of planning engineers. These reasons were not clear in the regulatory proposals and in many cases it appeared that DNSPs provided significantly more detail on how they planned the network rather than information to justify their forecasts. This assessment was supported by Nuttall Consulting's methodological review findings and detailed project reviews. Further, the AER considers that the Victorian DNSPs did not adequately provide a clear link in their regulatory proposals between the exercise of engineering judgement and the economic efficiency of the forecast.

The AER notes that the lack of economic analysis for the proposed forecasts was in most cases due to the fact that the business cases for investment are only taken a year prior to commencement of the project. Therefore, forecast projects are subject to significant changes in scope and timing when a more thorough analysis is undertaken at the business case stage. The AER agrees with Nuttall Consulting's findings that in many cases further cost benefit analysis may not support the proposed scope and timing of the projects as proposed in the DNSPs' forecasts at the time of the AER's review.

Based on its own investigation of the methodologies used to determine the reinforcement forecasts capex proposals the AER considers that the proposed forecasts based on a bottom up build of all projects do not adequately take account of the further detailed analysis and refinement of projects that results in the actual projects that are required and undertaken in the forecast period. This is consistent with previous regulatory control periods where actual expenditure has been considerably less than what DNSPs have originally forecast. Further, the AER considers that the forecasts need to take greater account of historical actual expenditure levels as a starting point for forecast expenditure.

With regards to the distribution transformer upgrade program, based on the information assessed by the AER, it agrees with the recommendations made by Nuttall Consulting that Jemena, SP AusNet and United Energy have not adequately justified that their proactive replacement program will effectively reduce failure rates of distribution transformers. The AER further concurs with Nuttall Consulting and the businesses that in many cases the distribution transformers most susceptible to faulting would have been detected and replaced following the January 2009 heatwave. Furthermore, that following the rollout of the AMI, the AER also considers that better data will be available to more efficiently target faulty distribution transformers. Therefore the AER agrees with the recommendation made by Nuttall Consulting that there is a low to moderate probability that programs proposed by Jemena, SP AusNet and United Energy will be required in the forthcoming regulatory control period.

The AER notes that in relation to Jemena's property purchases for zone substations, $11.5 million in direct costs has been transferred from proposed non-network other capex to proposed reinforcement expenditure, consistent with section 8.12.2. This has been included in Jemena's total reinforcement expenditure assessed by the AER.

Based on the analysis undertaken by the AER, it considers that each DNSP has not adequately justified that the proposed increases in forecast reinforcement expenditure reasonably reflects the capex criteria. It considers that greater emphasis should be given to historical expenditure as a basis of forecast expenditure. In determining an alternative reinforcement expenditure forecast for each Victorian DNSP, the AER agrees with Nuttall Consulting's recommendations that resulted from its technical review of the methodologies that were used to determine the proposed reinforcement capex forecasts and the detailed project reviews that supported these findings. Therefore the AER considers that allowing for Nuttall Consulting's recommendations as a proportion of the proposed expenditure for each DNSP, based on its weighted probability analysis and outlined in table 8.25, provides an estimate of expenditure forecast for each DNSP that reasonably reflects the capex criteria, taking into account the capex factors outlined in section 8.8.2.

Table 8.25 Reinforcement expenditure—proportion of DNSPs' proposed expenditure allowed for in AER draft decision (per cent)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Proportion of DNSPs' proposed expenditure	39	62	38	53	63

Note: In the AER's draft decision these percentages are applied to the proposed direct reinforcement costs.

In terms of profiling the alternative forecast reinforcement expenditure across each year of the forthcoming regulatory control period, the AER concurs with the approach recommended by Nuttall Consulting that expenditure is likely to increase over the regulatory control period, given the expected increasing demand on the network over time. The AER has therefore has applied an annual growth factor to profile the recommended amount of expenditure to allow for an increasing level expenditure over the forthcoming regulatory control period for each DNSP.

8.8.8 AER Conclusion

For the reasons discussed and as a result of the AER's analysis of the regulatory proposals and Nuttall Consulting's report recommendations, the AER is not satisfied that the proposed reinforcement capex forecast by CitiPower, Powercor, Jemena, SP AusNet and United Energy reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors. The AER agrees with Nuttall Consulting that reducing each DNSP's proposed reinforcement expenditure to the expenditure outlined in table 8.26 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 outlined section 8.8.2.

The AER notes that although the Victorian DNSPs have indicated they have prepared their capex forecasts on a detailed project-by-project basis, and the AER has for the most part assessed expenditure in this way, the AER's conclusions relate to a total forecast capex allowance for this capex cost category. Within the approved total capex allowance, each DNSP retains discretion regarding the allocation and expenditure of capital. The AER expects each DNSP to be responsive to changing conditions in order to meet customer requirements while managing and operating the network in accordance with good electricity industry practice. If any matter arises which requires a DNSP to reorder its priorities then it is appropriate for the DNSP to do so.

Table 8.26 AER conclusion on reinforcement capex for Victorian DNSPs ($'m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	39.6	32.4	36.5	11.2	11.9	131.5
Powercor	26.4	28.1	29.9	31.7	33.7	149.8
Jemena	10.1	10.9	11.8	12.7	13.7	59.1
SP AusNet	28.3	31.0	33.8	36.9	40.3	170.3
United Energy	24.7	25.2	25.7	26.2	26.7	128.4
Total	**129.2**	**127.5**	**137.6**	**118.7**	**126.3**	**639.2**

Note: These numbers are at a direct cost level and exclude the AER's draft decision on margins, overheads and real cost increases.

8.9 Reliability and Quality Maintained (RQM)

8.9.1 Introduction

This section focuses on capital expenditure to replace and renew existing network assets to maintain the reliability and quality of supply. With time, network assets age and deteriorate and, if not replaced, may fail, resulting in a deteriorating level of service reliability and quality.

The reliability and quality maintained capex category does not include expenditure to improve the reliability and quality of supply. The incentive mechanism to improve performance is covered under the STPIS.

8.9.2 Approach

In assessing and determining whether each of the Victorian DNSPs' proposed RQM forecast and the AER's estimate of the required forecast RQM capex which reasonably reflects the capex criteria, the AER has had regard the capex factors as relevant. Specifically the AER's analysis of forecast RQM capex takes into account:

- the benchmark capex that would be incurred by an efficient DNSP over the regulatory control period.[104]

Appendix I of this draft decision (which should be read in conjunction with this chapter) sets out the AER's analysis which benchmarks the Victorian DNSPs against their interstate counterparts including benchmarking the DNSPs' forecasts against the AER's forecasts to assess the efficient level of RQM capex for the forthcoming regulatory control period.

- the actual and expected capex of the DNSP during the current and previous regulatory control periods.[105]

The AER has compared the actual capex incurred during these regulatory control periods against the DNSPs' proposed capex and the AER's estimate of the required capex for the forthcoming regulatory control period taking into account any observed trends in actual capex. Due to calibration concerns as to whether the DNSPs' forecasting models could reliably predict future asset replacement requirements, the AER has applied its repex model instead to forecast the required RQM capex.

Where[106]:

- the results of the DNSPs' forecasting models were greater than that of the repex model or
- the DNSPs' forecast RQM capex was significantly greater than actual capex incurred during the previous and current regulatory control periods,

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[104] NER clause 6.5.7(e)(4).
[105] NER clause 6.5.7(e)(5).
[106] As per clause NER 6.5.7(e)(3) the AER further investigated why there was a difference in the results.

the AER further investigated:

- the policies, procedures, and forecasting methodologies associated with the targeted matters
- whether there is a justifiable need for the proposed investment
- whether other reasonable options were considered instead of replacement (that is, deferrals) and the most efficient outcome selected to satisfy that need.[107]

In conducting the review of the DNSPs forecast RQM capex allowance, the AER assumed the current level of capex to be a representation of an efficient base[108] to maintain reliability and quality of supply.[109]

The AER's repex model

In September 2009 the AER engaged Nuttall Consulting to develop a replacement capex forecasting model similar to those applied by Ofgem in the UK. The model produced by Nuttall Consulting forecasts replacement needs at an aggregate level using age as a proxy for the many factors that drive individual asset replacements. The model was also calibrated so that it reflected historical levels and costs.

In assessing previous regulatory proposals, the AER noted that the DNSPs utilised complex forecasting models to forecast their RQM capex need. As some of these models were black boxed propriety models, the AER was unable to assess the underlying assumptions within and confirm the outputs of these models.

For this draft decision, the AER's approach has been to utilise the DNSPs' historical replacement data to forecast their RQM capex requirements for the forthcoming regulatory control period. This provides a useful reference to assess regulatory proposals. This approach allows a common framework to be applied without the need to be overly intrusive in data collection and detailed analysis of the asset management plans.[110]

A full explanation of the model can be found in section 3 of the Nuttall Consulting Report.

8.9.3 Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs have proposed a RQM capex allowance of $1.3 billion over the forthcoming regulatory control period. The AER notes:

- the apparent pre-mature timing[111] for asset replacements

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[107] NER clause 6.5.7(e)(10)
[108] Please refer to Appendix I of this draft decision for further details.
[109] NER clause 6.5.7(e)(8).
[110] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 29.
[111] Refers to an accelerated level of asset replacements compared to the current regulatory control period.

- insufficient economic justification behind some replacement programs
- issues with the apparent scoping and costing of projects
- the replacement programs does not reflect known condition of assets
- the inaccuracy of the DNSPs' historical forecasts compared to actual expenditure.

The following table summarises the Victorian DNSPs' RQM forecasts.

Table 8.27 Victorian DNSPs' proposed RQM forecasts for the forthcoming regulatory control period ($'m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	126.0	45.0	54.6	48.5	50.9	58.9	258.0	105
Powercor	215.3	72.2	71.8	74.1	73.1	73.2	364.4	69
Jemena	65.0	30.4	27.9	27.5	31.9	33.8	151.5	133
SP AusNet	169.0	48.6	61.0	53.8	51.3	43.6	258.4	53
United Energy	131.5	60.6	58.3	56.5	50.5	51.2	277.2	111
Total	**706.8**	**256.8**	**273.7**	**260.5**	**257.8**	**260.7**	**1309.4**	**85**

Note: Direct costs only.
Source: RQM reconciliation to RIN by asset class.

8.9.4 Summary of submissions

Victorian Minister for Energy and Resources

The Hon. Peter Batchelor MP, Minister for Energy and Resources, submitted that the AER should consider historical trends when determining each DNSPs' capex allowance. The Minister noted the difficulties faced by the ESCV in setting the capex allowance for the current regulatory control period. The Minister also noted the current underspend of the capex allowance by the DNSPs, despite significant reductions of this allowance for the current regulatory control period by the ESCV.[112]

Energy Users' Coalition of Victoria

The Energy Users' Coalition of Victoria (EUCV) submitted that:

- the AER should develop a holistic view on (other than the bottom up assessment of the Victorian DNSPs' applications) whether the proposed capex programs are valid and whether consumers will be able to pay for the hikes in revenue

[112] Minister of Energy and Resources, *Submission on the Victorian electricity network service providers' regulatory proposal for 2011–2015*, p. 2.

- the AER should undertake careful analysis to ensure that the proposed capex programs are not being made when the imperative to do so is low, and where deferment would lead to lower (and therefore more efficient) costs

- the AER should require DNSPs to demonstrate a need for replacements versus the risk of deferrals. Furthermore, the AER should investigate the timing of expenditure versus the costs of early investments

- the AER has a responsibility to ensure that the Victorian DNSPs' capex claims are fully justified and supported by evidence

- the EUCV was also concerned that the DNSPs were replacing assets earlier than their end of life—with consumers bearing the costs for early replacement.[113]

Consumer Action Law Victoria

Consumer Action Law Centre (CALC) noted:

- the capex forecasts may indicate inefficient management of capex

- while some overspend may indicate a need for increased capex, closer scrutiny should be applied to ensure that 'gold-plating' was not occurring

- there appears to be evidence of a disparity between asset ageing and responsible asset management

- the deliverability of the program should be taken into account

The CALC also recommended the AER to further scrutinise the proposals to determine the efficiency of forecast capex (including unit costs), to track the expenditure outcomes for future determinations, and to introduce a wide capital works model.[114]

Consumer Utilities Advocacy Centre

Consumer Utilities Advocacy Centre (CUAC) questioned and noted:

- the similar reason (ageing of assets) cited by the DNSPs for an increase in the capex allowance in the current and forthcoming regulatory control periods

- whether the forecast capex can be deferred and, if approved, whether the capex program can be delivered

- the process may be an opportunity for businesses to gold plate the networks at high cost to consumers.

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[113] Energy Users Coalition of Victoria, *Response to 2010 AER review of Victorian Electricity DBs applications*, February 2010, pp. 10,12,16,25 and 28.

[114] Consumer Action Law Centre, *Submission to the Review of initial Distribution Network Service Providers' Proposals for the 201 –2015 Regulatory Control Period*, 16 February 2010, pp. 2,4,8,11 and 16.

Accordingly, the CUAC recommended the AER to carefully examine the costs and benefits to consumers.[115]

Energy Users Association of Australia

The Energy Users Association of Australia (EUAA):

- noted that the level of proposed capex by the businesses appeared to be excessive
- recommended that the AER take into account the capex factors outlined in the NER, including benchmarking.[116]

Origin

Origin noted the assessments made by Jemena's capex consultant GHD and recommended the AER to apply the same scrutiny to all capex forecasts.[117]

8.9.5 Consultant review

As part of its review of the DNSPs' RQM capex proposal, Nuttall Consulting reviewed the documentation provided by the DNSPs, sought more detailed information on specific projects and undertook a series of meetings with the DNSPs. From its review, Nuttall Consulting concluded that:

- The capital governance and practices of the DNSPs were well-evolved, fit-for-purpose capital governance processes and practices.[118] However, the full extent of these processes has not been applied to these plans. That is, the level of evaluation and justification that may be expected prior to the approval of specific proposed projects and programs have not been applied to the DNSPs' forecasts.
- The DNSPs have not adequately demonstrated that the model inputs and assumptions were "fit for purpose" in terms of enabling a 'bottom-up' build that was a reasonable estimator of overall prudent and efficient expenditure.
- There was insufficient detail on how the DNSPs have managed the risk over the current regulatory control period and why it was justified that these risks must be removed, and how risks will change moving into the forthcoming regulatory control period.
- There was a lack of economic analysis provided for some projects to demonstrate that the project/s scope and timing are required.[119]

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[115] Consumer Utilities Advocacy Centre, *Response to the Victorian distribution businesses regulatory proposals*, 17 February 2010, p. 5.
[116] Energy Users Association of Australia, *AER Review of Victorian electricity distribution prices and distributors' proposals for the period 2011–2015*, 12 February 2010, p. 13.
[117] Origin, *Response to Victorian DNSPs regulatory proposals*, 11 February 2010, p. 6.
[118] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review* 22 May 2010, p. 41.
[119] ibid., pp. 64–66.

Nuttall Consulting also undertook replacement expenditure (repex) modelling using models developed for the AER for each business. This repex modelling work is described in detail in Section 3 of Nuttall Consulting's report.

Nuttall Consulting's proposed adjustments to each DNSPs' proposed RQM forecast can be found in section 4 of its report.

Where Nuttall Consulting determined that the DNSPs' forecasts should not be accepted, Nuttall Consulting, in consultation with the AER, generally adopted a revealed cost approach to establishing an alternative view. In particular, the average of the audited actual expenditure in the current regulatory control period was adopted as a best estimate of likely future needs. It should also be noted that Nuttall Consulting's work was conducted on a 'fully absorbed' cost basis which the AER subsequently converted to a direct cost basis in consultation with Nuttall Consulting.

8.9.6 Issues and AER considerations

This section details the AER's considerations in reviewing the DSNPs' proposed RQM allowance. In assessing the DNSPs' forecasts the AER has had regard to the capex factors as outlined in section 8.9.2.

Although DNSPs have prepared their forecasts at the function code level, the AER's assessments and decision ultimately relate to a total forecast capex allowance. Within the approved total capex allowance, each DNSP retains discretion regarding the allocation and expenditure of capital. The AER expects each DNSP to be responsive to changing conditions in order to meet customer requirements while managing and operating the network in accordance with good electricity industry practice. If any matter arises which requires a DNSP to reorder its priorities then it is appropriate for the DNSP to do so.

Where the AER has recommended an adjustment to the forecast RQM expenditure within this subsection, the adjustment was made by subtracting the DNSP's forecast against the AER's repex model forecast.

Response to submissions

The AER's analysis of past RQM capex estimation and implementation found consistent evidence of systemic bias and/or inaccurate estimation of future capex requirements consistent with the concerns raised in the submissions noted above. These findings are discussed in more detail in the following sections.

The AER notes the EUCV's concerns regarding the DNSPs' forecasts capex. In assessing and determining whether each of the Victorian DNSPs' proposed capex forecast and the AER's estimate of the required forecast capex which reasonably reflects the capex criteria, the AER has had regard the capex factors as relevant. Specifically the AER's analysis of forecast capex takes into account the EUCV's comments in:

- assessing the DNSPs' capex forecasts through a variety of methodologies, top down, bottom up and benchmarking

- assessing the timing of the capex program and the justification behind them including options for deferrals.

In response to the EUCV's specific concerns that the DNSPs may be replacing assets before the end of their useful lives, the AER is not in a position to dictate when asset replacements should occur. That is a task that is appropriately allocated to the DNSPs. The AER assessment has examined the asset replacement strategies of the DNSPs and has sought to examine whether those strategies are prudent and efficient. The AER's investigation has generally found there is evidence that the Victorian DNSPs have achieved significant and worthwhile extensions in plant life for a number of categories of plant and equipment. The AER is satisfied that the Victorian DNSPs' practices are appropriate in this regard and that there is no evidence of premature replacement of assets.

The AER notes the CALC's, CUAC's, EUAA's and Origin's concerns regarding the DNSPs' forecasts capex. In assessing and determining whether each of the Victorian DNSPs' proposed capex forecast and the AER's estimate of the required forecast capex which reasonably reflects the capex criteria, the AER has had regard the capex factors as relevant. Specifically the AER's analysis of forecast capex takes into account the stakeholder's comments in:

- benchmarking[120] and assessing the DNSPs' historical and forecast capex
- assessing the timing of the capex program (including deliverability) and the justification behind them including options for deferrals.

In response to the CALC's specific recommendation regarding tracking expenditure for future determinations, the AER has over time expanded its data collection and accordingly. The AER is continuing to establish policies, techniques and standardised systems and processes for data collection. The AER is also in the process of modifying RINs and the annual reporting regime to improve the data collection for future determination purposes.

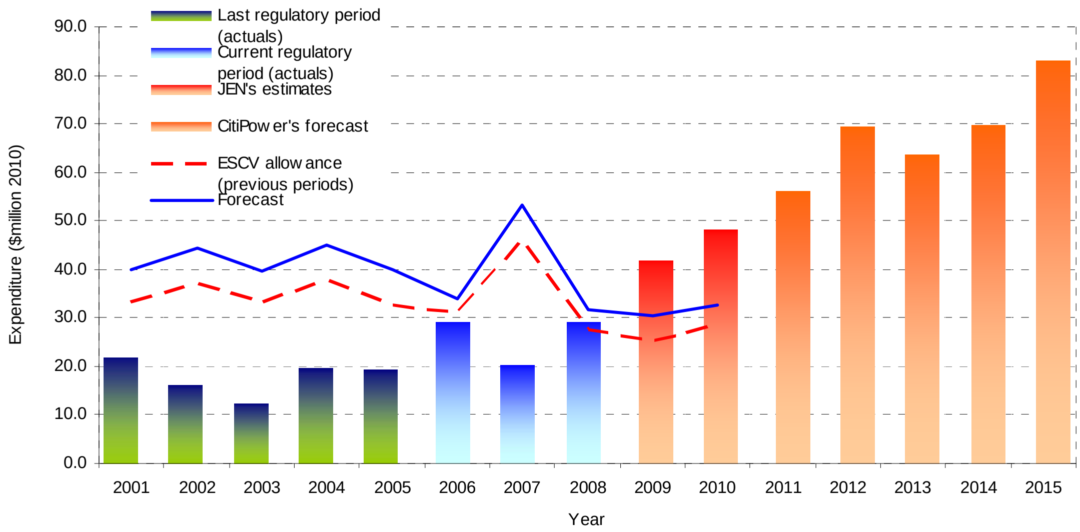
In response to the EUAA's specific concern regarding benchmarking, the AER's response to this submission can be found in Appendix I of this draft decision.

CitiPower

CitiPower proposed a RQM capex allowance of $258 million ($2010) for the forthcoming regulatory control period. Its proposal highlighted a need for capex to be raised significantly in the forthcoming regulatory control period to manage existing faults levels and to replace ageing assets.[121] Figure 8.3 illustrates CitiPower's RQM capex for the previous, current and forthcoming regulatory control periods. Figure 8.3 also includes CitiPower's forecasts and the ESCV's allowance for the two previous regulatory control periods.

120 The AER's response to benchmarking can be found in appendix I of this draft decision.
121 CitiPower, *Regulatory proposal*, p. 116.

Figure 8.3 CitiPower RQM capex— historical and proposed ($’m, 2010)



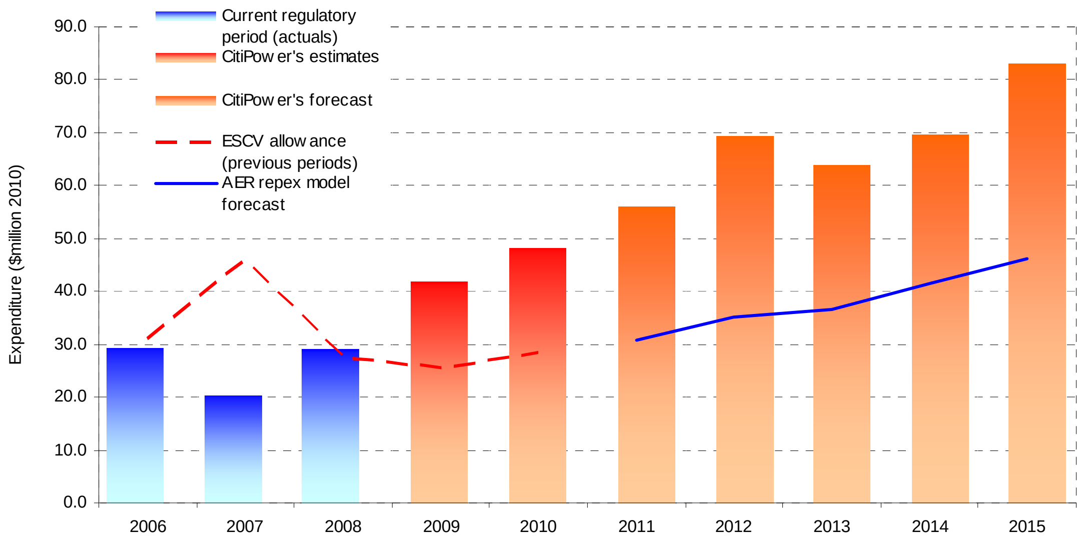
Source: RIN templates. These numbers are fully absorbed as historical allocations were not available.

Figure 8.3 demonstrates that CitiPower has:

- consistently forecast a higher level of expenditure than what was required
- a tendency to underspend its RQM capex allowance.

The AER has applied CitiPower's historical asset data to its repex model and the AER's forecast for CitiPower is illustrated in figure 8.4.

Figure 8.4 AER's forecast on RQM capex for CitiPower ($’m, 2010)



Source: RIN templates and AER's repex model. These numbers are fully absorbed as historical allocations were not available.

The AER has reviewed the information provided by CitiPower in support of its forecast RQM allowance, including that associated with the ageing of its networks and the purported effects of climate change on its networks in the forthcoming regulatory control period.

As indicated in the section 8.9.2, the AER's top down investigation has targeted particular areas of concern and its considerations of these issues are outlined below.

Fault level mitigation

CitiPower has proposed $75 million ($2010) for a new fault level mitigation program to keep the fault levels on its network to within plant ratings in the forthcoming regulatory control period. CitiPower currently manages fault levels by opening selected zone substation circuit breakers to allow fault levels to drop. However, when customers connect an embedded generator, the presence of the generator can cause an increase in the potential fault level on the network.

CitiPower contracted Sinclair Knight Merz (SKM) to undertake analysis of different investment options and make recommendations to mitigate fault levels. CitiPower has used this recommendation to prepare this proposal.[122]

The AER has reviewed the SKM report and accepts that the engineering solution to address this issue as selected by CitiPower is appropriate. However, although enhancing the CitiPower network to accept more embedded generators will provide a benefit for those customers wanting to connect an embedded generator, it is not apparent that this cost should be borne by all customers. In addition, apart from an engineering assessment,[123] the AER consider that there was a lack of economic analysis and justification behind the fault level mitigation project. The AER considers the lack of economic analysis means the efficiency of CitiPower's approach cannot be ascertained with any certainty. Additionally, the underlying reasons put forward for this program appear to be a known historical issue and risks, which are currently tolerated and managed.

Nuttall Consulting also raised the same concerns about the lack of economic analysis behind this proposal[124] and it recommended[125] that the proposed expenditure not be supported in the forthcoming regulatory control period.

Specifically the AER considers CitiPower:

- has not quantified the benefits and outcomes for all customers that will achieved by the forecast level of investment. Furthermore it was not apparent to the AER why this cost should be borne by all customers when the beneficiaries are new embedded generators

122 Citipower, *Regulatory proposal*, p. 108.

123 Sinclair Knight Merz, *Fault level Mitigation Issues Paper Embedded Generation in CitiPower Distribution System*, p. 32–37.

124 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 107–108.

125 ibid., p. 108.

- has not demonstrated an underlying need for this investment nor has it provided an economic justification
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period.

For the reasons discussed above, the AER is therefore not satisfied that the fault level mitigation proposal reasonably reflects the efficient costs that a prudent operator in the circumstances of CitiPower would require to achieve the capex criteria including the capex objectives.

The AER agrees with Nuttall Consulting's recommendations that the proposed expenditure is not supported and no allowance should be allocated for this program. The AER's adjustments to CitiPower's forecast can be found in table 8.28. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Zone substation plant replacement

CitiPower proposed $64 million ($2010) in the forthcoming regulatory control period for the replacement of primary plants[126] within the zone substations. CitiPower stated that the primary drivers of expenditure for this category were for zone substation transformers and switchgear replacements.

CitiPower have used the Condition Base Risk Management (CBRM)[127] model to the forecast replacements volumes for zone substations transformers and circuit breakers (CBs).[128] The CBRM methodology determines the probability of failure based on the age of asset and expected life, actual performance, operational experience, environmental conditions and manufacturer and specification. The probability of failure is generally described in terms of a health index. As the probability of failure increases the health index increases. Health indices are derived for different asset groups and calibrated using failure rates. The future health index for individual items of plant is derived from the current health index and operating conditions. This is aggregated and allows future failure rates for asset classes to be calculated.

The AER has reviewed the CBRM and acknowledges that it may be a useful tool for forecasting asset replacement. However, it is also important to note that any model output projections are a function of a combination of inputs, the assumptions used and calibrations made to the model. The AER has reviewed the inputs, outputs and assumptions of the CBRM and agrees with Nuttall Consulting:

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126 The major components of expenditure being power transformers and HV circuit breaker replacements.

127 CBRM is a process that enables companies to use current asset information, engineering knowledge and practical experience to predict future asset condition, performance and risk for their network assets. The output from the CBRM is a health rating from 0–10—the higher the rating the worst the condition of the asset.

128 CitiPower, *CitiPower CBRM - TX v3.0.xls, CitiPower CBRM - NPV TX v3 1.xls, CitiPower 11 6.6kVCB CBRM v3.0.xls and CitiPower 11 6.6kVCB CBRM - NPV v3.0.xls*

- With respect to the inputs for transformers, concerns regarding the disparity between the Dissolved Gas Analysis (DGA)[129] test results on the condition of transformers and the resulting output of the CBRM.[130] Put simply, the current health index of the transformer does not reflect its current condition as highlighted in CitiPower's own test results.

- With respect to the assumptions for transformers, concerns regarding CitiPower's use of an international failure probability rate that was inconsistent with its own historical data. Specifically, the model used by CitiPower has assumed a major transformer failure every 2 years while its Assets Management Plan (AMP) indicates that only 3 major transformer failures have occurred in the last 15 years.[131] As the failure rate is a major factor in determining optimal replacement timing, the application of this generic factor has resulted in an exaggerated output.

- With respect to circuit breakers, concerns regarding the assets life[132] assumption and its effects on the outputs. As the age of the asset is a major factor in determining optimal replacement timing, any overestimation of the asset's age profile may result in an exaggerated output.

- With respect to the assumptions for circuit breakers concerns regarding CitiPower's use of an international failure probability rate that was inconsistent with its own historical data.[133] As the failure rate is a major factor in determining optimal replacement timing, the application of this generic factor has resulted in an exaggerated output.

The AER agrees with Nuttall Consulting that CitiPower's CBRM forecast does not reflect its future replacement needs. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.[134]

The AER agrees with Nuttall Consulting's concern that CitiPower has not adequately demonstrated that the outputs from the CBRM are 'fit for purpose'. Specifically, Nuttall Consulting stated:

> In our opinion, this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that

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129 Dissolved Gas Analysis is a test performed on oils from transformers. As the insulating materials in a transformer break down due to thermal and electrical stresses, gaseous by-products are formed. The by-products are characteristic of the type of incipient-fault condition.

130 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 110.

131 CitiPower, *C0104 - Asset Management Plan - CP Zone Substation Transformers 1.0*, p. 23. Nuttall Consulting, *Victorian Electricity Distribution Revenue Review, May 2010*, p. 111.

132 With time, network assets age and deteriorate and, if not replaced, may fail, resulting in a deteriorating level of service reliability and quality.

133 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 111.

134 CitiPower, *CitiPower's response - AER CAPEX Guidance Paper 231209 v3*, p. 5, CitiPower, *C0102 - Asset Management Plan - CP HV Circuit Breakers 1.0*, p. 27, *C0033 - Transformer Replacement Plan Methodology*, p. 4, *C0104 - Asset Management Plan - CP Zone Substation Transformers 1.0*, p. 27.

> the number of failures, probability of failure, the ageing relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account CitiPower’s historical information, including failure statistics, asset condition monitoring results and risk mitigation measures.[135]

Given the issues highlighted above the AER agrees with this assessment.

For the reasons discussed, and as a result of the AER’s consideration of CitiPower's regulatory proposal, Nuttall Consulting’s report and other material, the AER is not satisfied the zone substation replacement category forecast reasonably reflects the capex criteria, including the capex objectives. The AER's adjustments to CitiPower's forecast can be found in table 8.28. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Zone substation secondary systems replacement

CitiPower proposed $29.1 million ($2010) in the forthcoming regulatory control period for the replacements of secondary[136] systems within the zone substations. The drivers[137] of expenditure for this category appear to be an increase in the level of expenditure for current programs and proposals for new programs.[138]

The AER notes that a major portion of the proposed expenditure is due to an ongoing program to replace aged relays. The AER has reviewed the documentation[139] provided for this program and observed that a decline in volume of replacements is forecast for the forthcoming regulatory control period. However this decline in volumes was not matched by relative expenditure declines but rather, showed a constant rate in total

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135 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 112.

136 Relay replacement, battery banks and chargers, switch controllers, supervisory cable replacements, secondary works associated with fault level management, transformer protection inhibit program, unplanned capital replacement.

137 CitiPower, *CP 156 - Ageing Unreliable Relay Replacement, CP 156 - Replacement Battery Banks and Chargers, CP 156 - Replacement of Ageing Switch Controllers, CP 156 - Replacement of Supervisory Cable with Existing OFC, CP 156 - Secondary Works Associated with Fault Level Management, CP 156 - Transformer Protection Inhibit Program, CP 156 - Unplanned Capital Replacement, p. 1–2s. CitiPower, C0103 - Asset Management Plan - CP Underground cables 1.0, CitiPower, CP 156 - AC Board Upgrades, CP 156 - Augmentation Associated with SP AusNet Projects, CP 156 - Bush Fire Royal Commission Out Workings, CP 156 - Capacitor Controller Replacements, CP 156 - Communications Network Equipment Replacements, CP 156 - Control Room Modifications, CP 156 - DC Supplies, AmpHour Capacity and Fusing Upgrades, CP 156 - Duplicate protection on Buses and CB Backup, CP 156 - Duplicate Protection on Selected Feeders, CP 156 - Duplicate Protection on Tied 66 kV Lines, CP 156 - Establish 3 Phase VTs on 66kV Lines, CP 156 - Install Auto Reclose on 66kV and 22kV Buses, CP 156 - Protection Reviews and Implementations*, pp. 1–2s.

138 These new programs include replacing aged DC intertrip schemes, installing new transformer inhibit schemes, relay replacements due to terminal station rebuilds, undertaking a number of protection reviews, installing duplicate protection, upgrading AC and DC supplies, replacing aged switch controllers, establishing VTs on some 66 kV lines, control room modifications, replacement of aged communications equipment and installation of auto-reclose schemes.

139 CitiPower, *CP-Relays-003 nw ver 1.0, CP 156 - Ageing Unreliable Relay Replacement, CP Asset Management Plan - CP 11 Protection Equipment Relays V1 0.*

expenditure.[140] The AER was not able to establish a reason for this level expenditure based on the information provided by CitiPower.[141]

Regarding other current programs and new work programs, the underlying reasons outlined to justify an increase or new expenditure appears to be known historical issues, risks and/or changed business practices, all of which are currently tolerated and managed. Nuttall Consulting also shared the same concerns regarding this proposal[142] and it recommended that the proposed expenditure not be supported in the forthcoming regulatory control period and to only allow for existing levels of expenditure with some allowance for an increasing expenditure based upon the ageing of the network.[143]

Specifically, the AER considers CitiPower:

- has not demonstrated an underlying need for this investment nor has it provided an economic justification
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not quantified the benefits and outcomes for customers that will achieved by the forecast level of investment.
- has not demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, CitiPower did not establish a clear link between its exercise of engineering judgement and economic efficiency
- has not adequately demonstrated how its forecasts were a reflection of its Asset Management Plans (AMPs), that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure.

For the reasons discussed, and as a result of the AER’s consideration of CitiPower's regulatory proposal, Nuttall Consulting’s report and other material, the AER is not satisfied the zone substation secondary systems replacement category reasonably reflects the capex criteria, including the capex objectives. The AER's adjustments to CitiPower's forecast can be found in table 8.28. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

HV switch replacement

CitiPower proposed $15 million ($2010) in the forthcoming regulatory control period for the replacements of Low Voltage (LV) and High Voltage (HV) switchgear. CitiPower stated that the reasons behind the programs were to ensure that the high voltage switches are safe to operate and are in a reliable and serviceable condition.

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140 CitiPower, *CP 156 - Ageing Unreliable Relay Replacement*, p. 1.
141 ibid., p. 1.
142 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 113–114.
143 ibid., p. 114.

The bulk of the expenditure for this category relates to the replacements of the Nilsen LV air circuit breakers ($5.8 million over 5 years).[144]

Regarding Nilsen LV circuit breaker replacements, CitiPower stated that two of its Nilsen LV circuit breakers have failed in the past (one in 2005 and the other in 2007).[145] Following detailed failure investigations, CitiPower stated that it was committed to a replacement of this series of LV Circuit Breaker (over a defined period) as an effective means of addressing the risk of failure of the remaining population.[146] Although circuit breaker failures may impose some risk on CitiPower's Network, with only 2 failures in 4 years, it was not apparent to Nuttall Consulting and the AER why CitiPower considered it necessary to replace its entire population (97) of Nilsen LV circuit breakers in the forthcoming regulatory control period.

Similar to the Nilsen, the underlying reasons presented for an increase in expenditure in other programs in this category appears to be known historical issues, risks and/or a change in business practices, which are currently tolerated and managed. The AER considers these programs revolve around internal decisions as to the appropriateness of a process to address known concerns. Nuttall Consulting also shared the same concerns regarding this proposal[147] and it recommended[148] that the proposed expenditure not be supported in the forthcoming regulatory control period and to only allow for existing levels of expenditure with some allowance for an increasing expenditure based upon the ageing of the network.

Specifically, CitiPower:

- has not demonstrated an underlying need for this investment nor has it provided an economic justification
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not quantified the benefits and outcomes for customers that will achieved by the forecast level of investment.
- has not demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, CitiPower did not establish a clear link between its exercise of engineering judgement and economic efficiency
- has not adequately demonstrated how its forecasts were a reflection of its AMPs, that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure.

For the reasons discussed, and as a result of the AER’s consideration of CitiPower's regulatory proposal, Nuttall Consulting’s report and other material, the AER is not

144 CitiPower, CP *143 -Nilsen*, p. 1.
145 ibid., p. 5.
146 ibid., p. 5.
147 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 116–117.
148 ibid., p. 117.

satisfied the HV function code forecast reasonably reflects the capex criteria, including the capex objectives. The AER's adjustments to CitiPower's forecast can be found in table 8.28. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Services replacement

CitiPower proposed $7.9 million ($2010) in the forthcoming regulatory control period for the replacements of customer service lines and cables. Similar to other categories in this subsection, CitiPower has proposed sharp increases in expenditure for the forthcoming regulatory control period. The bulk of the expenditure in this function code relates to CitiPower's aerial service program.

CitiPower advised that the forecast volumes for its aerial service program was calculated by dividing the number of services with the design life of 60 years and adjusting it for replacements that have occurred in other function codes.[149]

The AER has reviewed the justification for the proposed expenditure but again was unable to determine how historical expenditure, engineering judgement and the removal of a vegetation allowance constituted the 158 per cent increase in forecast expenditure.[150] Nuttall Consulting also shared the same concerns regarding this proposal[151] and it recommended[152] that the proposed expenditure not be supported in the forthcoming regulatory control period and to only allow for existing levels of expenditure with some allowance for an increasing expenditure based upon the ageing of the network.

Specifically, CitiPower:

- has not demonstrated an underlying need for this investment nor has it provided an economic justification
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not quantified the benefits and outcomes for customers that will achieved by the forecast level of investment
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, CitiPower did not establish a clear link between its exercise of engineering judgement and economic efficiency.

For the reasons discussed, and as a result of the AER’s consideration of CitiPower's regulatory proposal, Nuttall Consulting’s report and other material, the AER is not satisfied the services replacement function code forecast reasonably reflects the capex

149 CitiPower, *CP 153 - Service Replacement*, p. 1, *CP 152 Aerial service program*, p. 1.
150 ibid., p. 1.
151 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 118.
152 ibid.

criteria, including the capex objectives. The AER's adjustments to CitiPower's forecast can be found in table 8.28. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Other high volume low costs asset replacements

This section outlines the AER's considerations for the fuse and surge diverters and transformer replacement categories. Due to the relatively small size of the programs involved ($3.0 million over the forthcoming period - $2010) the AER will not discuss this in great detail.

Similar to other categories outlined in this subsection, CitiPower did not provide sufficient information[153] to validate the increase in expenditure from historical trends. Nuttall Consulting also shared the same concerns[154] regarding this proposal and it recommended[155] that the proposed expenditure not be supported in the forthcoming regulatory control period and to only allow for existing levels of expenditure with some allowance for an increasing expenditure based upon the aging of the network.

Specifically, CitiPower:

- has not demonstrated an underlying need for this investment nor has it provided an economic justification
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not quantified the benefits and outcomes for customers that will achieved by the forecast level of investment
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, CitiPower did not establish a clear link between its exercise of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that these function codes reasonably reflects the efficient costs that a prudent operator in the circumstances of CitiPower would require to achieve the capex criteria including the capex objectives. The AER's adjustments to CitiPower's forecast can be found in table 8.28. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

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153 CitiPower, *CP 144 Indoor Substations, CP 144 Ground Type Substations, CP 144 Kiosk, CP 144 Pole Type Substations, CP 145 Distribution Surge Arrestor, CP 145 Fault Indicator, CP 145 HV Fuse, CP 145 LV Fuses, Isolators, Fused Isolators and CBs*, pp. 1s.

154 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 121 and 124.

155 ibid., pp. 121 and 124.

Reliability

CitiPower proposed $4.2 million ($2010) in the forthcoming regulatory control period to instigate projects to address worst served customers.[156]

The AER notes that there was no expenditure against this function code prior to 2009. For the current regulatory control period these tasks were allocated to another function code. Similar to other categories outlined in this subsection, CitiPower did not provide sufficient information to validate a need for this expenditure.

Specifically, CitiPower:

- has not demonstrated an underlying need for this investment nor has it provided an economic justification
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not quantified the benefits and outcomes for customers that will achieved by the forecast level of investment
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, CitiPower did not establish a clear link between its exercise of engineering judgement and economic efficiency.

Given that the above, the AER agrees with Nuttall Consulting that, assuming that similar works in the current regulatory control period have been captured in the other RQM activity codes, the allowance for the forthcoming regulatory control period should already be captured in other programs or categories.[157] The AER's adjustments to CitiPower's forecast can be found in table 8.28. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Fault related expenditure

In its proposal CitiPower proposed a RQM capex allowance of $11.7 million ($2010)[158] to cover covers fault related replacements.[159] The AER considered this to be an unusual forecast, as it was proposing a $23.7 million decline in expenditure from the current regulatory control period. CitiPower has since informed the AER of this error and has revised its forecasts to $22.4 million for the forthcoming regulatory control period. Given that this forecast was in line with historical expenditure and the AER's repex model forecast, the AER has accepted it as been reasonable.

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[156] CitiPower, *CP 166 - Animal Mitigation, CP 166 - HV Fuse Installation on Spur Lines, CP 166 - HV Line Covering, CP 166 - Installation of Additional Fault Indicators, CP 166 - Installation of CCT Conductor, CP 166 - Installation of LV Spreaders, CP 166 - Remote Alarm Indication at Obstructed Access Substations*.

[157] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review, May 2010*, p. 119.

[158] This is fully absorbed.

[159] These programs involve fault restoration works that require asset replacement to restore supply.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of CitiPower's regulatory proposal, Nuttall Consulting's report, other material and the capex factors, the AER is not satisfied CitiPower's forecast reasonably reflects the capex criteria, including the capex objectives. In coming to this view the relevant capex factors which the AER has specifically taken into account in assessing the forecast RQM capex include:

- benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period[160]
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods.[161]

The AER considers that reducing CitiPower's RQM forecast capex by the amounts shown in table 8.28 is the minimum adjustment necessary for it to be satisfied it reasonably reflects the capex criteria, including the capex objectives.

Table 8.28 AER conclusion on RQM capex for CitiPower ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	45.0	54.6	48.5	50.9	58.9	258.0
Less function code adjustments						
Fault level mitigation project	13.4	14.5	14.3	15.2	14.4	71.7
HV fuse unit & surge divert. repl.	0.2	0.2	0.2	0.1	0.1	0.8
HV switch replacement	2.5	2.5	2.2	2.0	1.7	11.0
Reliability	0.8	0.9	0.8	0.8	0.8	4.2
Services	1.2	1.1	0.9	0.8	0.7	4.7
Transformer replacement	0.2	0.1	0.1	0.0	–0.0	0.3
Zone substation plant replacement	–1.6	4.1	–1.9	–2.6	4.4	2.5
ZSS - Secondary systems replacement	4.9	5.2	5.2	5.1	5.0	25.4
Total adjustments	21.7	28.6	21.8	21.5	27.1	120.7
Total	**23.3**	**26.0**	**26.7**	**29.5**	**31.8**	**137.2**

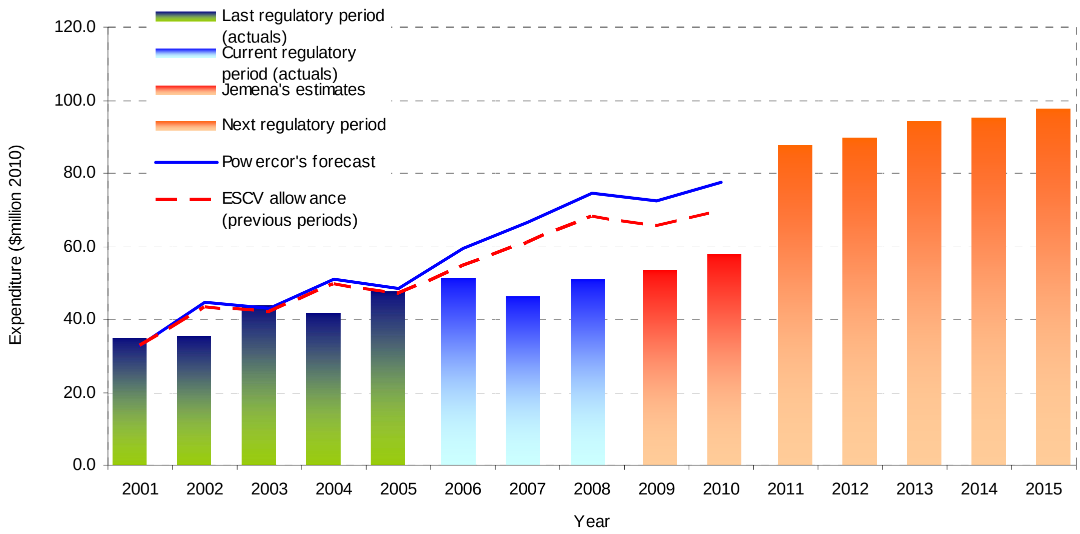
160 NER clause 6.5.7(e)(4). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

161 NER clause 6.5.7(e)(5). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

Powercor

Powercor proposed a RQM capex allowance of $464 million ($2010) for the forthcoming regulatory control period. Its proposal highlighted a need for RQM capex to be raised significantly to manage risks of asset failures and to replace ageing assets.[162] Figure 8.5 illustrates Powercor's RQM capex for the previous, current and forthcoming regulatory control periods. Figure 8.5 also includes Powercor's forecasts and the ESCV allowance for the two previous regulatory control periods.

Figure 8.5 Powercor RQM capex— historical and proposed ($'m, 2010)



Source RIN templates. These numbers are fully absorbed as historical allocations were not available.

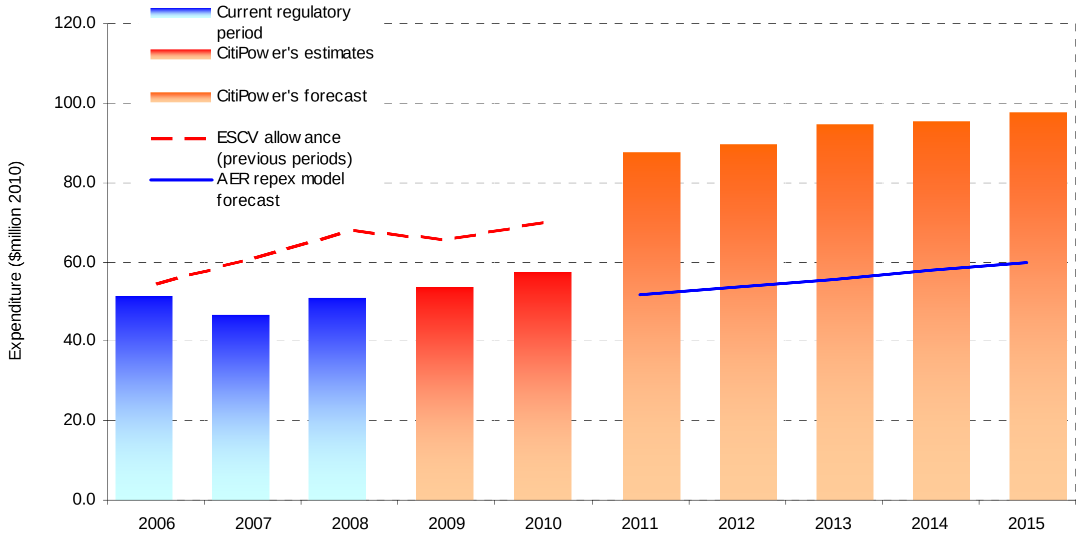
Figure 8.5 demonstrates that Powercor has:

- consistently forecast a higher level of expenditure than what was required
- a tendency to underspend its RQM capex allowance.

The AER has applied Powercor's historical asset data to its repex model and the AER's forecast for Powercor is illustrated in figure 8.6.

[162] Powercor, *Regulatory proposal*, p. 71.

Figure 8.6 AER's forecast on RQM capex for Powercor ($’m, 2010)



Source RIN templates and AER's repex model. Excludes conductor replacement program. These numbers are fully absorbed as historical allocations were not available.

The AER has reviewed the information provided by Powercor in support of its forecast RQM allowance, including that associated with the ageing of its network and the purported effects of climate change on its network in the forthcoming regulatory control period.

As indicated in the ‘approach’ section, the AER's top down investigation has targeted particular areas of concern and its considerations of these issues are outlined below.

Conductor replacement program

Powercor proposed $101.6 million ($2010) for the forthcoming regulatory control period to instigate a pro-active replacement to prepare for, anticipated increases in high voltage overhead conductor failures. Powercor's intention is to replace all high voltage overhead conductors installed before 1971 over a 40-year period commencing in 2011.

The main driver for this replacement program appears to be bushfire risks.

However, in conducting its review of this proposal[163], Nuttall Consulting and the AER is concern that, without the bushfire risk, the program would not be justifiable given the deficiency of Powercor's proposal in that it:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification

163 Powercor, *PAL 150 Overhead line replacement*, p. 1. PAL *07 Sub transmission and HV conductors V1.0*, p. 22.

- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing

- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Powercor has not established a clear link between its use of engineering judgement and economic efficiency

- has not adequately demonstrated how its forecasts were a reflection of its AMPs, that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure.

Nuttall Consulting also shared the same concerns[164] regarding this proposal and it recommended[165] an allowance based on historical expenditure to be provided for current activities to continue pending a later consideration of enhanced activities in response to the outcome of the VBRC. The AER considered Nuttall Consulting's view but considers however that the recent 2009 experience of bushfires in Victoria demonstrates that a case can be made for enhanced expenditure on conductor replacement. For this proposed expenditure the AER considers it unlikely that historical expenditure alone is the best guide to the efficient level of capex.

To establish an appropriate allowance for this activity the AER has conducted further analysis of the Powercor proposal. Powercor proposed that it replace its ageing conductors over a 40 year period at a constant rate. The AER used the Powercor data in the AER's repex model to determine the implied lifetime of the overhead conductor asset, which was 67 years. In consultation with Nuttall Consulting the AER has then modelled the estimated quantity of overhead conductor to be replaced in the forthcoming regulatory control period. To these volume estimates the AER has applied an average unit costs[166] rate for undertaking this activity.[167]

As noted in its analysis, Nuttall Consulting found that the justification for enhanced expenditure for this activity was related to bushfire risk. The AER acknowledges Nuttall Consulting’s concern[168] that Powercor may be unable to adequately target the conductors to be replaced so as to address this specific risk. However, the AER believes that is reasonable to expect that with appropriate application of internal knowledge as to the status and condition of their assets Powercor will be able to achieve at least 80 per cent accuracy. Therefore, the AER's view of the efficient level of capex has been adjusted accordingly.

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164 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 187-188.
165 ibid., p. 188.
166 Powercor response to AER information request 20091222, AER to DNSPs - Repex modelling inputs (Powercor) MASTER v1 3 22Dec 09.
167 The AER has compared Powercor's unit costs against other DNSPs and considered the proposed unit costs to be on the high side. The AER has adopted an average unit cost for conductors.
168 ibid., p. 188.

For the reasons discussed, and as a result of the AER's consideration of Powercor's regulatory proposal, Nuttall Consulting's report and other material, the AER is not satisfied the conductor code forecast reasonably reflects the capex criteria, including the capex objectives. The AER's adjustments to Powercor's forecast can be found in table 8.29. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Zone substation replacement

Powercor proposed $34.6 million ($2010) in the forthcoming regulatory control period for the replacements of primary plant within the zone substations. Powercor stated that the primary drivers of expenditure for this category were for zone substation transformers and switchgear replacements.

Powercor has used the Condition Base Risk Management (CBRM) [169] model to the forecast replacements volumes of zone substations transformers and circuit breakers. The CBRM methodology determines the probability of failure based on the age of asset and expected life, actual performance, operational experience, environmental conditions and manufacturer specification. The probability of failure is generally described in terms of a health index. As the probability of failure increases the health index increases. Health indices are derived for different asset groups and calibrated using failure rates. The future health index for individual items of plant is derived from the current health index and operating conditions. This is aggregated and allows future failure rates for asset classes to be calculated.

The AER has reviewed the CBRM and acknowledges that it may be a useful tool for forecasting asset replacement. However, it is also important to note that any model output projections are a function of a combination of inputs, the assumptions used and calibrations made to the model. The AER has reviewed the inputs, outputs and assumptions of the CBRM and agrees with Nuttall Consulting:

- With respect to the inputs for transformers, concerns[170] regarding the disparity between the degree of polymerisation[171] and the resulting output of the CBRM. Put simply, the current health index of the transformer did not reflect its current condition as highlighted in Powercor's own test results.

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[169] Powercor, *CBRM.xls, Powercor CBRM - NPV TX v2 0.xls, Powercor 22kVCB CBRM.*

[170] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 190.

[171] The degree of polymerization (DP) test is another means for assessing insulation aging. This test is performed on paper samples. The DP test provides an estimate of the average polymer size of the cellulose molecules in materials such as paper and pressboard. Generally, paper in new transformers has a DP of about 1000. Aged paper with a DP of 200–260 has little remaining mechanical strength, and therefore makes windings more susceptible to mechanical damage during movement, particularly during extreme events such as through-faults. A critical piece of condition information concerns the winding insulation which the DP test assesses, as this is the most critical factor that defines the end of life of the transformer.

- With respect to the assumptions for transformers, concerns[172] regarding Powercor's use of an international failure probability rate that was inconsistent with its own historical data. Specifically, the model used by Powercor has assumed a major transformer failure every 1.5 years while its AMP[173] was unclear on the frequency of major failure in the last 5 years. As the failure rate is a major factor in determining optimal replacement timing, the application of this generic factor has resulted in an exaggerated output.

- With respect to circuit breakers, concerns[174] regarding the assets life assumption and its effects on the outputs. As the age of the asset is a major factor in determining optimal replacement timing, any overestimation of the asset's age profile may result in an exaggerated output.

- With respect to the assumptions for circuit breakers, concerns regarding Powercor's use of an international failure probability rate that was inconsistent with its own historical data.[175] As the failure rate is a major factor in determining optimal replacement timing, the application of this generic factor has resulted in an exaggerated output.

The AER agrees with Nuttall Consulting that Powercor's CBRM forecast does not reflect its future replacement needs. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.[176]

The AER also notes Nuttall Consulting's concern that Powercor has not adequately demonstrated that the outputs of the CBRM are 'fit for purpose'. Specifically, Nuttall Consulting stated:

> In our opinion, this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that the number of failures, probability of failure, the ageing relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account Powercor's historical information, including failure statistics, asset condition monitoring results and risk mitigation measures.[177]

Given the issues highlighted above the AER agrees with this assessment.[178]

For the reasons discussed, and as a result of the AER's consideration of Powercor's regulatory proposal, Nuttall Consulting's report and other material, the AER is not satisfied the zone substation replacement category forecast reasonably reflects the capex criteria, including the capex objectives. The AER's adjustments to Powercor's

172 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 190–191.
173 Powercor, *P0104 - Asset Management Plan - PAL Zone Substation Transformers 1.0*, p. 17.
174 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 191.
175 Powercor, *P0102 - Asset Management Plan - PAL HV Circuit Breakers 1.0*, pp. 21–22.
176 Powercor, *PAL- AER Capex Guidance Paper 110110 Final Response Chapters 2–5*, p. 12.
177 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 192.
178 ibid.

forecast can be found in table 8.29. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Zone substation secondary systems replacement

Powercor proposed $30.8 million ($2010) in the forthcoming regulatory control period for the replacements of secondary systems within the zone substations. The drivers of expenditure for this category appear to be an increase in the level of expenditures for current programs and claims for new programs.

The AER notes that a major portion of the proposed expenditure is due to an ongoing program to replace aged relays. The AER has reviewed the documentation[179] provided for this program and observed that a decline in volume of replacements is forecast for the forthcoming regulatory control period. However this decline in volumes was not matched by relative expenditure declines but rather, showed a constant rate in total expenditure. The AER was not able to establish a reason for this level expenditure based on the information provided by Powercor.[180]

Regarding current programs and new work programs, the underlying reasons put forward justify the expenditure appears to be known historical issues, risks and/or changed business practices, all of which are currently tolerated and managed. [181] The AER considers that this proposal revolves around internal decisions as to the appropriateness of a process to address known concerns. Nuttall Consulting also shared the same concerns[182] regarding this proposal and it recommended[183] that the proposed expenditure not be supported in the forthcoming regulatory control period and to only allow for existing levels of expenditure with some allowance for an increasing expenditure based upon the ageing of the network.

Specifically, the AER considers Powercor:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification (cost benefit analysis including options analysis)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing

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179 Powercor, *PAL 156 - Ageing Unreliable Relay Replacement, PAL-Relays-007 nw ver1.1, PAL Asset Management Plan - Protection Equipment _Relays_ PAL V0 2.*

180 Powercor, *PAL 156 - Ageing Unreliable Relay Replacement*, p. 1.

181 Powercor, *PAL 156 - AC Board Upgrades, PAL 156 - Augmentation Associated with SP AusNet* Projects, *PAL 156 - Bush Fire Royal Commission Out Workings, PAL 156 - Capacitor Controller Replacements, PAL 156 - Communications Network Equipment Replacements, PAL 156 - Control Room Modifications, PAL 156 - DC Supplies, AmpHour Capacity and Fusing Upgrades, PAL 156 - Duplicate protection on Buses and CB Backup, PAL 156 - Duplicate Protection on Selected Feeders, PAL 156 - Duplicate Protection on Tied 66 kV Lines, PAL 156 - Establish 3 Phase VTs on 66kV Lines, PAL 156 - Install Auto Reclose on 66kV and 22kV Buses, PAL 156 - Protection Reviews and Implementations*, pp. 1–2s.

182 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 194.

183 ibid.

- has not quantified the proposed benefits, risks and outcomes for customers that will be achieved by this proposal

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Powercor has not established a clear link between its use of engineering judgement and economic efficiency

- has not adequately demonstrated how its forecasts were a reflection of its AMPs, that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the zone substation secondary systems replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Powercor would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Powercor's forecast can be found in table 8.29. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Overhead and underground line replacement

Powercor proposed $12.6 million ($2010) in the forthcoming regulatory control period for the replacements of overhead and underground cables and their associated equipments. This forecast is a 1008 per cent increase from current expenditure.

The bulk of the expenditure for this category relates to the replacement of HV underground distribution cables. Powercor stated that the triggers for the replacement of underground cables were primarily derived from repetitive cable related failures.[184]

In relation to the forecasting method presented, Powercor outlined a purely age-based replacement scenario that assumes a percentage of cable needs to be replaced at particular ages, between 25 and 40 years. The AER agrees with Nuttall Consulting concerns[185] regarding the average age of replacement being earlier than expected. Given Powercor's:

- internal practices of replacing assets on condition[186]

- limited success in accurately forecasting its replacement needs using the same model since 2000

- actual expenditure compared to forecasts

the AER considers that Powercor’s expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program, with the risks remaining constant, the rationale for a 1008 per cent increase expenditure was not apparent. Furthermore, the AER notes the relatively low average age of

184 Powercor, *PAL 150 HV UG Distribution Cables*, p. 2.
185 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 195.
186 ibid., p. 195.

Powercor's HV underground cables (90 per cent of the population was less than 20 years old). Powercor also stated that overall performance levels of the population should not be adversely affected by age-related issues.[187] The AER also notes the relatively low level of cable related faults (most of which are joints and termination failures) in the current regulatory control period.[188] These rates alone do not justify the extent of the ramp-up in expenditure.

Regarding current programs and new work programs[189], the underlying reasons put forward to justify the expenditure appears to be known historical issues, risks and/or changed business practices, all of which are currently tolerated and managed. The AER considers that this proposal revolves around internal decisions as to the appropriateness of a process to address known. Nuttall Consulting also shared the same concerns[190] regarding this proposal and it recommended[191] that the proposed expenditure not be supported in the forthcoming regulatory control period and to only allow for existing levels of expenditure with some allowance for an increasing expenditure based upon the ageing of the network.

Specifically, Powercor:

- has not demonstrated an underlying need for this investment and to support it with economic justification (cost benefit analysis including options analysis)
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not attempted to quantify the benefits and outcomes for customers achieved by the forecast level of investment
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, Powercor did not establish a clear link between its exercise of engineering judgement and economic efficiency
- has not adequately demonstrated how its forecasts were a reflection of its AMPs, that is, how the application of the practices and procedures set out in its AMPs translated into its forecast expenditure.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the overhead and underground line replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Powercor would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Powercor's forecast can be found in table 8.29. In assessing

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187 Powercor, *P0103 - Asset Management Plan - PAL Underground cables 1.0*, p. 19.
188 ibid., p. 24.
189 Powercor, *PAL 150 HV UG Distribution Cable Joints, PAL 150 HV UG Distribution Cable, Silicon Injection, PAL 150 SWER ISO Earth Repair, PAL 150 UG Pillar-Pit Replacement, PAL 150 UG Service Cables and PAL 150 Under Verandah Replacement*. p. 1–2s.
190 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 195.
191 ibid., p. 195.

the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

HV and LV switch replacement

Powercor proposed $5.3 million ($2010) in the forthcoming regulatory control period for the replacements of Low Voltage (LV) and High Voltage (HV) switchgear. Powercor stated that the reason behind the program was to ensure that the high voltage switches are safe to operate and are in a reliable and serviceable condition.

The AER notes that the bulk of the expenditure for this category relates to the replacements of unserviceable gas switches ($4.5 million ($2010) over 5 years).[192]

The AER has reviewed the information provided by Powercor and was unable to determine the economic justification[193] behind the increase in expenditure. The underlying reasons put forward for an increase in expenditure programs in this function code appear to be known historical issues, risks and/or a change in business practices, which are currently tolerated and managed. The AER considers these programs revolve around internal decisions as to the appropriateness of a process. The AER also considers that such a business process change or improvement should be financed within the existing level of expenditure. Nuttall Consulting also shared the same concerns[194] regarding this proposal and it recommended[195] that the proposed expenditure not be supported in the forthcoming regulatory control period and to allow existing levels of expenditure with some allowance for an increasing expenditure based upon the ageing of the network.

Specifically, Powercor:

- has not demonstrated an underlying need for this investment and to support it with economic justification (cost benefit analysis including options analysis)
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not attempted to quantify the benefits and outcomes for customers achieved by the forecast level of investment
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, Powercor did not establish a clear link between its exercise of engineering judgement and economic efficiency.

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192 Powercor, *PAL 143 - HV Air Break Switches*, p. 2.

193 These documents are 1 page in length. Powercor, *PAL 143 - HV Air Break Switches, PAL 143 - Distribution Switches RMUs, PAL 143 - Distribution switches_ metal clad, PAL 143 - Gas Switches*

194 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 196.

195 ibid., p. 1936

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the HV and LV switch replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Powercor would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Powercor's forecast can be found in table 8.29. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Reliability

Powercor proposed $7.5 million ($2010) in the forthcoming regulatory control period to instigate projects to address worst served customers.[196]

The AER notes that there was no expenditure against this function code prior to 2009. For the current regulatory control period these tasks were allocated to other function code. Similar to other categories outlined in this subsection, Powercor did not provide sufficient information to validate a need for this expenditure.

Specifically, Powercor:

- has not demonstrated an underlying need for this investment nor has it provided an economic justification
- has not demonstrated why it cannot manage the associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period
- has not quantified the benefits and outcomes for customers that will achieved by the forecast level of investment
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure, in particular, Powercor did not establish a clear link between its exercise of engineering judgement and economic efficiency.

Given that the above, the AER agrees with Nuttall Consulting that, assuming that similar works in the current regulatory control period have been captured in the other RQM activity codes, the allowance for reliabity program expenditure for the forthcoming regulatory control period should already be provided in those activity codes.[197]

AER conclusion

For the reasons discussed, and as a result of the AER’s consideration of Powercor's regulatory proposal, Nuttall Consulting’s report, other material and the capex factors, the AER is not satisfied Powercor's forecast reasonably reflects the capex criteria, including the capex objectives. In coming to this view the relevant capex factors

[196] Powercor, *PAL 172 - 22 kV Worst Performing Feeders, PAL 172 - 22 kV Worst Served Customers, PAL 172 - 66 kV Dead Spot Program, PAL 172 - 66 kV Projects, PAL 172 - System Event Minor Reliability Projects.*

[197] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review, May 2010,* p. 198.

which the AER has specifically taken into account in assessing the forecast RQM capex include:

- benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period[198]
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods.[199]

The AER considers that reducing Powercor's RQM forecast capex by the amounts shown in table 8.29 is the minimum adjustment necessary for it to be satisfied it reasonably reflects the capex criteria, including the capex objectives.

Table 8.29 AER conclusion on RQM capex for Powercor ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	72.2	71.8	74.1	73.1	73.2	364.4
Less function code adjustments						
HV switch replacement	0.7	0.7	0.7	0.7	0.7	3.5
OH/UG line replacement	0.6	0.5	0.4	0.2	0.0	1.8
Reliability improvement	1.5	1.5	1.5	1.5	1.5	7.5
ZSS - plant replacement	3.5	2.9	3.9	2.1	1.8	14.2
ZSS - secondary systems replacement	4.1	3.9	3.7	3.6	3.4	18.8
Conductor	12.1	12.2	12.6	12.7	12.7	62.3
Total adjustments	22.6	21.7	22.8	20.8	20.1	108.0
Total	**49.6**	**50.2**	**51.3**	**52.2**	**53.1**	**256.4**

Jemena

Jemena proposed a forecast RQM capex allowance of $151.5 million[200] ($ 2010) for the forthcoming regulatory control period to:

- start replacing its ageing asset base
- better manage failure rates and

[198] NER clause 6.5.7(e)(4). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

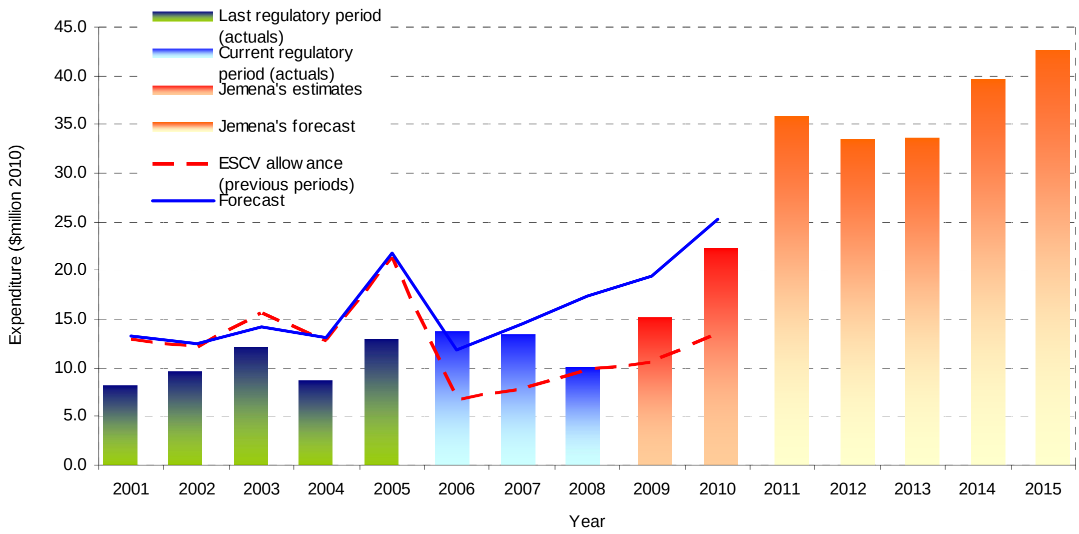
[199] NER clause 6.5.7(e)(5). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

[200] JEN, *Regulatory proposal*, RIN 2.1.

▪ minimise external impact such as climate change.[201]

Figure 8.7 illustrates Jemena's RQM capex for the previous, current and forthcoming regulatory control period. Figure 8.7 also includes Jemena's forecasts and the ESCV allowance for the two previous regulatory control periods.

Figure 8.7 Jemena RQM capex— historical and proposed ($'m, 2010)



Source: RIN templates. These numbers are fully absorbed as historical allocations were not available.

Figure 8.7 demonstrates that Jemena has:

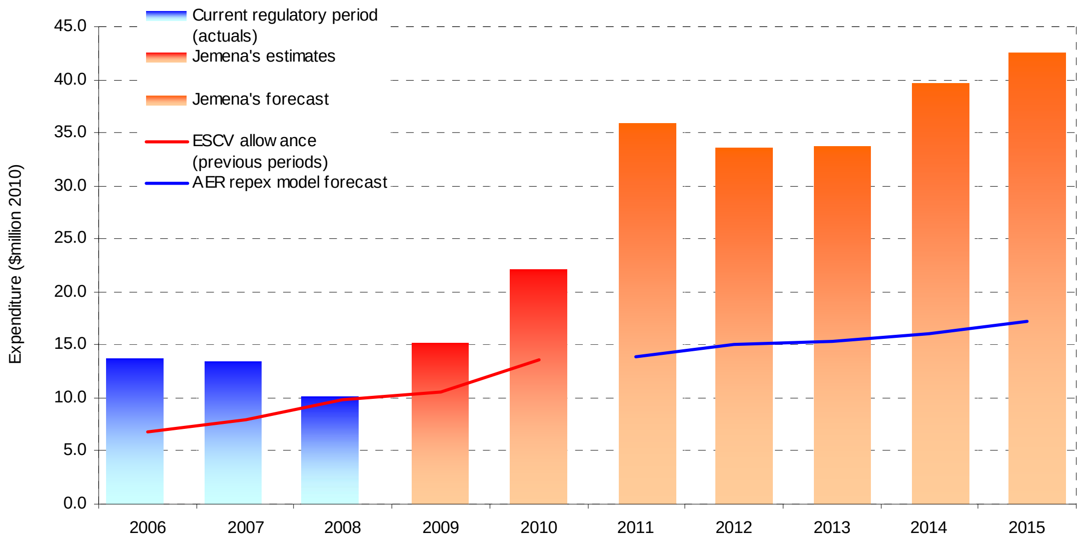
▪ consistently forecast a higher level of expenditure than what was required

▪ a tendency to underspend its RQM capex allowance.

The AER has applied Jemena's historical asset data to its repex model and the AER's forecast for Jemena is illustrated in figure 8.8.

[201] Jemena, *Network Asset Management Plan*, p. 104. A more detailed list of the reasons/drivers for the proposed expenditure can also be found on this page.

Figure 8.8 AER's forecast on RQM capex for Jemena ($’m, 2010)



Source: RIN templates and AER's repex model. These numbers are fully absorbed as historical allocations were not available.

The AER has reviewed the information provided by Jemena in support of its forecast RQM allowance, including that associated with the ageing of its networks and the purported effects of climate change on its networks in the forthcoming regulatory control period.

As indicated in section 8.9.2, the AER's top down investigation has only targeted particular areas of concern and its considerations of these issues are outlined below.

Pole top structures

Jemena proposed $35.9 million ($2010) for the forthcoming regulatory control period to instigate a pro-active replacement program aimed to replace ageing wooden cross arms and to mitigate pole fire risks.[202]

Jemena's forecast for its cross arms replacement program was based on the output of the PB replacement model. The AER has reviewed the output of the PB model and acknowledges that it may be a useful tool for forecasting asset replacement. However the output derived from any model is largely dependent on the sensitivity of input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted. Given Jemena's:

- internal practices of replacing assets on condition[203]
- limited success in accurately forecasting its replacement needs using the same model since 2000

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[202] Jemena Electricity Networks, *JEN 4356-103 pole top Life Cycle Management Plan - Issue1.0 - October 2009*. p. 5, *Network Asset Management Plan (NAMP) 2010–15*, pp. 112–113.

[203] Jemena Electricity Networks, *JEN 4356-103 pole top Life Cycle Management Plan - Issue1.0 -* October 2009. p. 6.

- actual[204] expenditure compared to forecasts

the AER considers that Jemena's expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program, with the risk remaining constant, the rationale for the $24.8 million increase expenditure was not apparent. Jemena stated that the volume forecast of the PB model was in line with the historical notification rates. However, the AER notes that Nuttall Consulting has considered[205] these rates and found that they alone do not fully justify the magnitude of the increase in Jemena's proposed expenditure. Furthermore, Nuttall Consulting was concerned with Jemena's definition of average life and replacement life.[206]

Having reviewed Jemena's forecast, the AER agrees with Nuttall consulting that Jemena has not adequately demonstrated that the model assumptions behind its forecasts are suitable for enabling a bottom-up build that is a reasonable estimation of overall prudent and efficient expenditure. In this regard, the AER does not consider that Jemena has demonstrated that rigorous approaches have been applied to calibrate the model for this purpose. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.[207] Nuttall Consulting also shared the same concerns regarding this proposal and it recommended an allowance based on historical trend with some allowance for the ageing of the network.[208]

Specifically, Jemena:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification (cost benefit analysis including options analysis)

- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing

- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Jemena has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the pole top structures replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Jemena would

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204 Jemena Electricity Networks, *JEN Capex by Purpose (Feb 2010).*

205 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 151.

206 As the age of the asset is a major factor in determining optimal replacement timing, that any overestimation of the asset's age profile may result in an exaggerated output.

207 Jemena Electricity Networks, *Appendix 9.1- Networks Asset Management Plan 2010–2015,* p. 25.

208 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 151..Include an allowance for the current level of activities for the bush fire mitigation program.

require to achieve the capex criteria including the capex objectives. The AER's adjustments to Jemena's forecast can be found in table 8.30. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Zone substation

Jemena proposed $29.4 million ($2010) in the forthcoming regulatory control period for the replacements of primary plant within the zone substations. Jemena stated that the primary drivers of expenditure for this category were for zone substation transformers and switchgear replacements.

For transformers, Jemena has used various condition tests results to assess the overall condition of the transformers. These test results are then used to determine which transformers should be targeted for replacement.

For the circuit breakers, a risk assessment exercise was performed to prioritise circuit breaker types for replacement. This assessment accounts for a number of factors including the condition, age, performance and operational aspects of the circuit breaker type.

For both transformers and circuit breakers, engineering judgement was then used to develop the replacement program, based upon the other considerations such as augmentation requirements and other replacement needs. For transformers, Jemena has also prioritised their replacements to coincide with the zone substation noise mitigation project.

The AER has reviewed the information provided by Jemena and agrees with Nuttall Consulting that the timing for replacement, based on condition of the transformer was not reasonable.[209] In fact, Jemena's life cycle management plan stated that the notional replacement dates for transformers (according to condition) should occur sometime after the forthcoming regulatory control period.[210] Regarding optimising transformer replacements to coincide with the noise mitigation program, Nuttall Consulting advised and the AER noted that Jemena did not provide any analysis on why it was undertaking the project early given that it stated that it can manage this noise issue late into the forthcoming regulatory control period.[211]

With regard to HV circuit breaker replacements, various factors, including risks, were used to determine the prioritisation of replacements.[212] The AER notes Nuttall Consulting's concerns regarding the weightings[213] that were applied to the various factors to determine the resulting prioritisation.[214] Furthermore, Nuttall Consulting

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209 Jemena Electricity Networks, *JEN 4356-156 Zone substation transformers life cycle management plan*, pp. 29, 30–34 and 27.
210 ibid., p. 27.
211 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 152–153.
212 Jemena Electricity Networks, *JEN 4356-151 ZSS Circuit Breakers*, pp. 23–29.
213 The weightings of risks directly influences the prioritisation for replacements
214 The ranking or order of when an asset should be replaced

concluded that Jemena's risk assessment was quite high-level, and did not allow risks to be readily compared from one element to another.[215]

Regarding switchgear, Nuttall Consulting was not satisfied that Jemena's pro-active replacement program was reasonable. In its investigation, Nuttall Consulting noted that the condition of the worst switchgear forecast to be replaced were still only at the lower end of what Jemena considers to be the unacceptable range.[216]

Specifically, Jemena:

- has not demonstrated an underlying need for a step increase in investment
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing
- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Jemena has not established a clear link between its use of engineering judgement and economic efficiency.

Given the issues highlighted above, the AER agrees with Nuttall Consulting's assessment and advice that the forecasts for this function code:

- are not reasonable
- only to allow for a RQM capex allowance that reflects historical trends with some allowance for the ageing of the network.[217]

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the zone substations replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Jemena would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Jemena's forecast can be found in table 8.30. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Pole replacement

Jemena proposed $21.3 million ($2010) for the forthcoming regulatory control period to instigate a pro-active replacement program aimed at replacing ageing and undersized poles.[218]

Jemena's forecast for its pole replacement program was based on the output of the PB replacement model. The AER has reviewed the output of the PB model and

215 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 150.
216 ibid., p. 152. Refers to the condition of the assets where they are deemed to require near term replacement.
217 ibid., p. 150.
218 Jemena Electricity Networks, *Appendix 9.1- Networks Asset Management Plan 2010–2015*, p. 111.

acknowledges that it may be a useful tool for forecasting asset replacement. However the output derived from any model is largely dependent on the sensitivity of input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted. Given Jemena's:

- internal practices of replacing assets on condition[219]
- limited success in accurately forecasting its replacement needs using the same model since 2000
- actual expenditure compared to forecasts[220]

the AER considers that Jemena's expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program, with the risk remaining constant, the rationale for the $18.5 million increase expenditure was not apparent. The AER also notes the concerns raised by Jemena's contracted consultant GHD. In their report on Jemena's forecast capex GHD noted:

> … there is inconsistency between the historic condition-based replacement trends and the forecast age-based replacement profiles.[221]
>
> The step change increase in the Capex program for poles over historic levels appears warranted if the replacement predictions are based on the age profile of the poles. However, without more detailed information on the prediction of remaining life of the remaining poles (and relying just on age), the step change increase does not appear to be completely robust.[222]

Having reviewed Jemena's forecast, the AER agrees with Nuttall Consulting that Jemena has not adequately demonstrated that the model assumptions behind its forecasts are suitable for enabling a bottom-up build that is a reasonable estimation of overall prudent and efficient expenditure. In this regard, the AER does not consider that Jemena has demonstrated that rigorous approaches have been applied to calibrate the model for this purpose. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.[223]

The other integral part in the rise in expenditure of Jemena's forecasts for this function code relates to the undersized pole replacement program. The underlying reasons put forward[224] for this program appear to be known historical issues, risks and/or a change in business practices, which are currently tolerated and managed. The AER considers that any business process changes or improvements should be financed within the

219 Jemena Electricity Networks, *Poles Life cycle management plan (JEN 4356-102)*, p. 13.
220 Wilson Cooke, *Electricity Distribution Price Review 2006: Principal Technical Consultant's Final Report*, p. 31.
221 GHD, *Independent Review of JEN Capital Expenditure Forecasts*, p. 72.
222 ibid., p. 34.
223 Jemena Electricity Networks, *Appendix 9.1- Networks Asset Management Plan 2010–2015,* p. 25.
224 Jemena Electricity Networks, *Poles Life cycle management plan (JEN 4356-102)*, p. 6.

current level of expenditure. Nuttall Consulting also shared the same concerns regarding the undersized pole replacement program.[225]

In summary, Nuttall Consulting also shared the same concerns[226] regarding this proposal and it recommended[227] an allowance based on historical trend with some allowance for the ageing of the network.

Specifically, Jemena:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing
- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Jemena has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the pole replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Jemena would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Jemena's forecast can be found in table 8.30. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Conductor replacement

Jemena proposed $18.6 million ($2010) for the forthcoming regulatory control period to instigate a replacement program to replace conductors and connectors in the overhead network.[228] Jemena has stated that it is expected that its new condition assessment methodology will result in the detection of increased quantities of deteriorated conductors.

Jemena's forecast for its conductor replacement program is based on the output of the PB replacement model. The AER has reviewed the output of the PB model and acknowledges that it may be a useful tool for forecasting asset replacement. However the output derived from any model is largely dependent on the sensitivity of input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted. Given Jemena's:

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225 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 155.
226 ibid., pp. 155.
227 ibid., pp. 155.
228 Jemena Electricity Networks, *Network Asset Management Plan (NAMP) 2010–15*, pp. 114–115.

- internal practices of replacing assets on condition[229]
- limited success in accurately forecasting its replacement needs using the same model since 2000
- actual[230] expenditure compared to forecasts

the AER considers that Jemena's expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program, with the risk remaining constant, the rationale for the $16.4 million increase in expenditure was not apparent. The AER also notes Nuttall Consulting's concerns regarding the inconsistency between the results of Jemena's inspection program and the resulting replacement levels in 2006.[231]

Having reviewed Jemena's forecast, the AER agrees with Nuttall Consulting that Jemena has not adequately demonstrated that the modelling assumptions behind its forecasts are suitable for enabling a bottom-up build that is a reasonable estimation of overall prudent and efficient expenditure. In this regard, the AER does not consider that Jemena has demonstrated that rigorous approaches have been applied to calibrate the model for this purpose. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.[232]

Nuttall Consulting also shared the same concerns[233] regarding this proposal and it recommended[234] an allowance based on historical trend with some allowance for the ageing of the network.

Specifically, Jemena:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing
- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal

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229 Jemena Electricity Networks, *JEN 4356-104 Connector and Conductor Life Cycle Management Plan* - Issue 1 - 31 August 2009, p. 9.
230 Jemena Electricity Networks, *JEN Capex by Purpose (Feb 2010).*
231 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 156–157, Jemena Electricity Networks, *Asset replacement forecast methodology*, p. 5, *JEN 20091029c - Info request - AER to DNSPs - Repex modelling inputs.*
232 Jemena Electricity Networks, *Appendix 9.1- Networks Asset Management Plan 2010–2015,* p. 25.
233 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 156–154.
234 ibid., p. 157.

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Jemena has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the conductor replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Jemena would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Jemena's forecast can be found in table 8.30. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Distribution switchgear

Jemena proposed $13.3 million ($2010) in the forthcoming regulatory control period for the replacements of HV switchgear. Jemena has stated that it is expected that its new condition assessment methodology will result in the detection of increased quantities of deteriorated switchgear.[235]

The AER has reviewed the information[236] provided by Jemena and notes that the underlying reasons put forward for an increase in expenditure programs in this function code appear to be known historical issues, risks and/or a change in business practices, which are currently tolerated and managed. While Jemena's new inspection program may find a need to replace more switchgear it should be noted that:

- the volumes of replacements are not definitive
- a detailed replacement program will not be developed prior to 2011 as Jemena's asset data are still lacking in factual data on failure rates, useful life and wear out[237]
- Jemena replaces assets on condition[238]

the AER considers that Jemena’s expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program, with the risk remaining constant, the rationale for the increase in expenditure was not apparent. The AER also notes that this forecasting exercise was undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.[239] Nuttall Consulting also shared similar concerns regarding this proposal and it recommended that the proposed expenditure not be supported in the forthcoming regulatory control period and only to

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235 Jemena Electricity Networks, *Asset Replacement Forecasting Methodology*, October 2009, .p. 6.

236 Jemena Electricity Networks, *Life Cycle Management Plan JEN 4356-105 Overhead Line Switchgear, JEN 4356-113 Non Pole Distribution Substations, JEN 4356-107 Automatic Circuit Reclosers, JEN 4356-109 HV Outdoor Fuses, JEN 4356-110 Surge Arrestors*

237 Jemena Electricity Networks, *Life Cycle Management Plan Non Pole Type Distribution Substation*, p. 6.

238 Jemena Electricity Networks, *Appendix 9.1- Networks Asset Management Plan 2010-2015,* p. 25.

239 ibid., p. 25.

allow for existing levels of expenditure with some allowance for an increasing expenditure based upon the ageing of the network.[240]

Specifically, Jemena:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification

- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing

- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal

- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Jemena has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the HV switch replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Jemena would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Jemena's forecast can be found in table 8.30. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Underground cables

Jemena proposed $7.6 million ($2010) for the forthcoming regulatory control period to instigate a replacement program to replace underground cables and associated underground replacements (that is, joints, terminations, link boxes etc).

Jemena's forecast for its underground cables replacement program is based on the output of the PB replacement model. The AER has reviewed the output of the PB model and acknowledges that it may be a useful tool for forecasting asset replacement. However the output derived from any model is largely dependent on the sensitivity of input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted. Given Jemena's:

- internal practices of replacing assets on condition[241]

- limited success in accurately forecasting its replacement needs using the same model since 2000

- actual[242] expenditure compared to forecasts

240 Nuttall Consulting, Victorian Electricity Distribution Revenue Review, May 2010, p. 165.
241 Jemena Electricity Networks, *JEN 4356-116 Underground Cables Systems*, pp. 9-10.
242 Jemena Electricity Networks, *JEN Capex by Purpose (Feb 2010).*

the AER considers that Jemena's expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program,[243] with the risk remaining constant, the rationale for the $5.4 million increase expenditure was not apparent.

Having reviewed Jemena's forecast, the AER agrees with Nuttall Consulting that Jemena has not adequately demonstrated that the model assumptions behind its forecasts are suitable for enabling a bottom-up build that is a reasonable estimation of overall prudent and efficient expenditure. In this regard, the AER does not consider that Jemena has demonstrated that rigorous approaches have been applied to calibrate the model for this purpose. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.[244]

In summary, Nuttall Consulting also shared the same concerns[245] regarding this proposal and it recommended[246] an allowance based on historical trend with some allowance for the ageing of the network.

Specifically, the AER considers that Jemena:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing
- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, Jemena has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the underground cables function code reasonably reflects the efficient costs that a prudent operator in the circumstances of Jemena would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Jemena's forecast can be found in table 8.29. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

243 Jemena Electricity Networks, *Asset Management Plan (NAMP) 2010–15,* pp. 130–131, *JEN 4356-116 Underground Cables Systems*, pp. 4–5.
244 Jemena Electricity Networks, *Appendix 9.1- Networks Asset Management Plan 2010–2015,* p. 25.
245 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 157–158.
246 ibid., p. 158.

Reliability

Jemena's expenditure forecast for its reliability program totals $7.3 million over the forthcoming regulatory control period. The drivers for this forecast appear to relate to meeting the reliability targets given expected worsening weather conditions.[247] Jemena stated the large portion of this work covers the installation and implementation of automatic circuit reclosers (presumably for reliability).[248]

The AER notes and agrees with Nuttall Consulting that the detailed justification[249] for the projects in this category was not clear, particularly with respect to their impact on reliability in the context of the significant increases in expenditure proposed elsewhere. However, assuming that the matters affecting reliability in the current regulatory control period are largely similar to those in the forthcoming regulatory control period (that is, 'business as usual') and in the absence of a more detailed and quantitative justification for the expenditure increase, the AER consider that an allowance based upon the historical level is reasonable. [250]

Consequently, based on the information provided by Jemena, Nuttall Consulting and its own analysis, the AER is not satisfied that the forecast expenditure for this function code reflects the efficient costs that a prudent operator in the circumstances of Jemena would require to achieve the capex criteria including the capex objectives. The AER's adjustments to Jemena's forecast can be found in table 8.30. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Jemena's regulatory proposal, Nuttall Consulting's report, other material and the capex factors, the AER is not satisfied Jemena's forecast reasonably reflects the capex criteria, including the capex objectives. In coming to this view the relevant capex factors which the AER has specifically taken into account in assessing the forecast RQM capex include:

- benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period[251]
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods.[252]

The AER considers that reducing Jemena's RQM forecast capex by the amounts shown in table 8.30 is the minimum adjustment necessary for it to be satisfied it reasonably reflects the capex criteria, including the capex objectives.

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247 The AER's assessments of the impact of climate change can be at the beginning of this chapter.
248 Jemena Electricity Networks, *Nuttall Info Request RQM asset view function view*
249 Jemena Electricity Networks, *JEN 4356-107 Automatic Circuit Recloser*
250 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 159.
251 NER clause 6.5.7(e)(4). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.
252 NER clause 6.5.7(e)(5). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

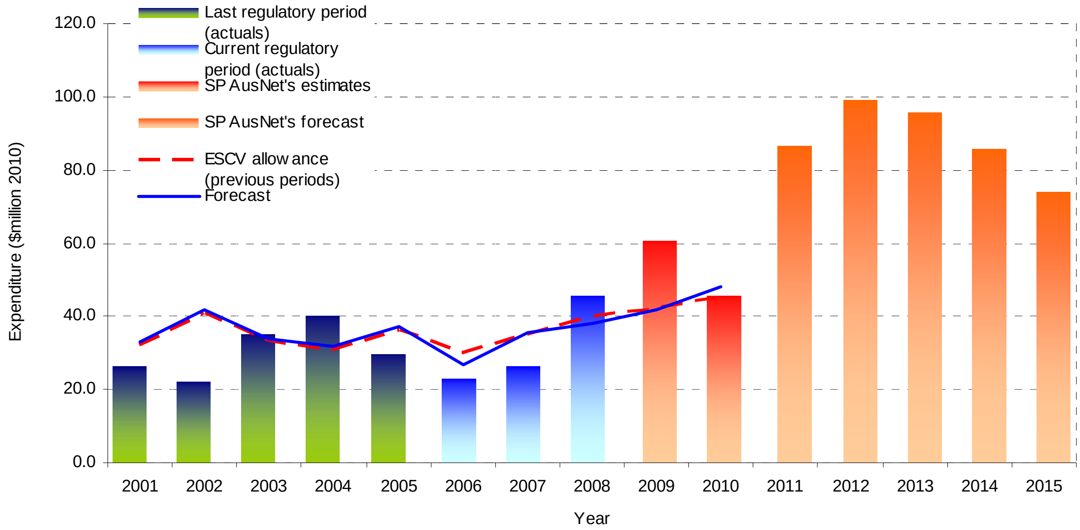
Table 8.30 AER conclusion on RQM capex for Jemena ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	30.4	27.9	27.5	31.9	33.8	151.5
Less function code adjustments						
Poles	1.6	2.4	3.0	3.3	3.4	13.8
Pole top structure	2.9	4.2	4.9	5.6	6.3	24.0
Conductors	4.6	2.5	2.1	2.4	3.2	14.8
Distribution transformers	0.1	–0.1	–0.1	–0.3	0.1	–0.2
Underground cables	0.3	0.3	0.7	1.3	1.5	4.1
Zone substation	5.0	3.8	3.1	4.6	4.6	21.1
Protection	0.4	–0.2	–0.3	0.8	–0.0	0.6
Distribution switchgear	2.1	0.9	0.1	–0.1	–0.1	2.8
Reliability maintained (performance)	1.0	0.8	0.7	0.7	0.7	4.0
Total adjustments	18.1	14.7	14.3	18.4	19.5	85.0
Total	**12.3**	**13.2**	**13.2**	**13.5**	**14.3**	**66.5**

SP AusNet

SP AusNet proposed a RQM capex allowance of $353.2 million ($2010) for the forthcoming regulatory control period. Its proposal highlighted a need for capex to be increased significantly in the forthcoming regulatory control period to manage safety obligations, deterioration of network conditions and compliance obligations for communication assets. Figure 8.9 illustrates SP AusNet's RQM capex for the previous, current and forthcoming regulatory control periods. Figure 8.9 also includes SP AusNet's forecasts and ESCV allowance for the two previous regulatory control periods.

Figure 8.9 SP AusNet RQM capex — historical and proposed ($’m, 2010)

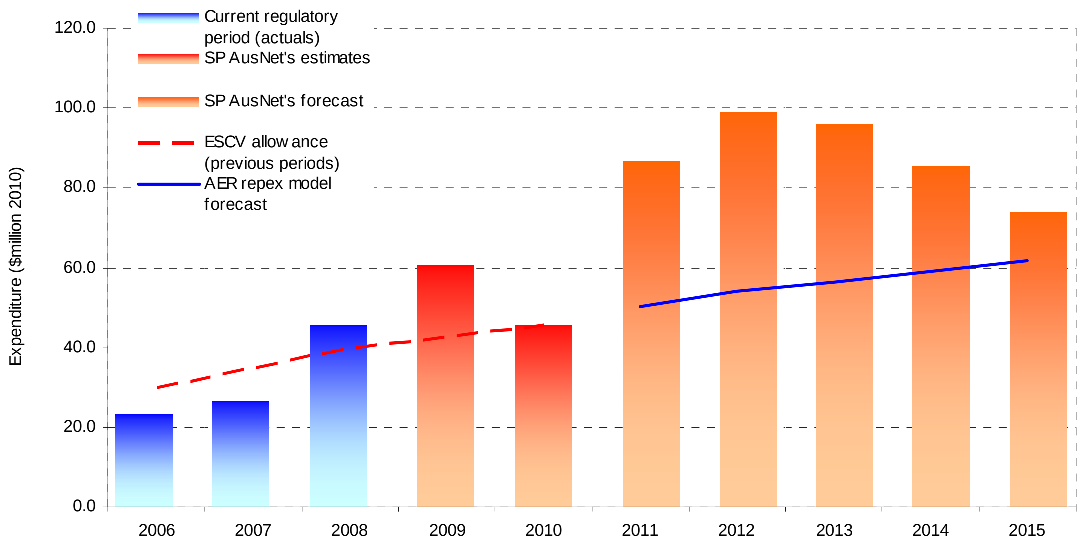


Source: RIN templates. These numbers are fully absorbed as historical allocations were not available.

Figure 8.9 demonstrates that SP AusNet has difficulties in accurately forecasting its RQM capex needs.

The AER has applied SP AusNet's historical asset data to its repex model and the AER's forecast for SP AusNet is illustrated in figure 8.10.

Figure 8.10 AER's forecast on RQM capex for SP AusNet ($’m, 2010)



Source: RIN templates and AER's repex model. These numbers are fully absorbed as historical allocations were not available. The forecast for the forthcoming regulatory control period includes expenditure forecasts for environmental, safety and legal (ESL) that was assessed under RQM under the "business as usual basis". It should be noted that these amounts were rejected under ESL but as they were recurrent expenditure and not new obligations, were assessed under RQM.

Zone substation plant

SP AusNet proposed $112.7 million ($2010) in the forthcoming regulatory control period for the replacements of primary plant within the zone substations. SP AusNet stated that the primary drivers of expenditure for this category were for zone substation transformers and switchgear replacements.

Forecasting methodology

SP AusNet has developed quantitative risk models for a broad range of its assets, including circuit breakers and power transformers. The risk model outputs contain, for each asset subject to SP AusNet's condition assessment, a risk ranking or prediction (specifically, the probability of failure and consequence of failure) relative to all other assets in the fleet. The models also allow for cost and benefits assessments (including deferral and/or optimising the timing of replacements) as well allowing for adjustments of risks and conditions from procedural interventions.

For each of the asset classes covered by the quantitative asset failure risk models, SP AusNet's Assets Management Strategy (AMS) describes current priorities for replacement over the forthcoming regulatory control period. In the AMS, the outcomes of specific asset failure risk mitigation goals over the forthcoming regulatory control period are presented in terms of a recommended risk level for each asset class as at 2008. The recommended or target risk level outlined in the AMS is associated with replacement of a specific amount of assets (each with its own relative condition ranking), and hence underpins a large component of SP AusNet's forecast capex proposal.

AER considerations

It was clear from the AER's investigation that the quantitative asset failure risk model outputs are a critical input underpinning SP AusNet's proposed forecast capex allowance. The AER notes however, that the application of the risk model outputs allows SP AusNet to retain a great degree of control over its asset base, and represents the first step in SP AusNet's analysis of an asset replacement decision.

From the documentation provided, Nuttall Consulting and the AER noted that SP AusNet has relied heavily on the probability of failure aspect of risk to justify its proposed replacement capex. However in its investigation, Nuttall Consulting noted that the model's output for transformers might not be a reflection of its condition in that:

- only three out of the twenty transformers proposed for replacement were at or near their end of life (according to the degree of polymerisation[253] levels - DPs of 200-250)

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[253] The degree of polymerization (DP) test is another means for assessing insulation aging. This test is performed on paper samples. The DP test provides an estimate of the average polymer size of the cellulose molecules in materials such as paper and pressboard. Generally, paper in new transformers has a DP of about 1000. Aged paper with a DP of 200-260 has little remaining mechanical strength, and therefore makes windings more susceptible to mechanical damage during movement, particularly during extreme events such as through-faults. A critical piece of condition

- the probability for core and coil failures may be higher than historical rates[254]
- the condition score (1-5) given to the asset may not be a reflection of the assets condition (also applies to the circuit breaker model)
- the assumed life (one of the factors within the model) may be lower than end of economic life
- the consequences and resulting risks of failures may not be equivalent to historical levels (also applies to the circuit breaker model).

For these reasons Nuttall Consulting concluded that the model may be overstating risks.[255]

With regard to the substation rebuild economic analysis, Nuttall Consulting had the same concerns as those outlined above. Furthermore, Nuttall Consulting noted that:

> …the project reports provided by SP AusNet, do not address the make-up of the risks and the small-scale measures that may be applied to optimise the specific actions to mitigate these risks.[256]

The AER has undertaken an analysis of the information[257] presented by SP AusNet regarding the transformer and circuit breaker replacements. The AER considers that SP AusNet has not demonstrated a clear economic need to replace these units over the forthcoming regulatory control period. Although the transformers and CB risk model outputs indicate an urgent need for replacement, the AER was not satisfied that these models have been adequately calibrated to reflect the conditions of these assets or the resulting risks and the consequences of failure.

At this stage, the AER therefore accepts Nuttall Consulting advice that there is considerable discretion for SP AusNet to further defer and optimise most of these programs. Consequently, based the information provided by SP AusNet, Nuttall Consulting and its own analysis, the AER is therefore is not satisfied that the forecast

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information concerns the winding insulation which the DP test assesses, as this is the most critical factor that defines the end of life of the transformer.

254 SP AusNet, *AMS 20-71 Power Transformers and Station Voltage Regulators, p. 35, 2011_2020 Transformer Program with Refurbishments (Hazard Function)*

255 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 234.

256 ibid., p. 234.

257 SP AusNet, *AMS 20-71 Power Transformers and Station Voltage Regulators, AMS 20-128 Power Transformer Risk Model Description, 2011_2020 Transformer Program with Refurbishments (Hazard Function), AMS 20-120 Replacement and Refurbishment Program for Power Transformers and Station Voltage Regulators, AMS 20-124 Details of Power Transformers and Station Voltage Regulators, AMS 20-54 Circuit Breakers, AMS 20-129 Circuit Breaker Risk Model Description, SCENARIO 17 (Hazard Function), AMS 20-121 Circuit Breaker Risk Ranking, AMS 20-107 Circuit Breakers –Summary of Issues & Strategies, AMS 20-123 Circuit Breaker Replacement/Retirement Program, Power Transformer Failure Consequences Model , Copy of V3 - Zone Sub Consequence Model.xls, SPA email response Vic review: replacement info request Qu 1,2,3,5 & 7, 5 March 2010, SPA email Vic review: replacement info request Qu 4 9 March, QA Response - Qu 89 B Nuttall, AMS 20-404N-1 RUB A Eco Evaluation Integrated Project 170310.xls, AMS 20-405N-1 SMR Eco Evaluation Integrated Project 170310.xls, AMS 20-407N-1 YPS Eco Evaluation Integrated Project 170310.xls.*

expenditure for the zone substations category reasonably reflects the efficient costs that a prudent operator in the circumstances of SP AusNet require to achieve the capex criteria including the capex objectives. The AER's adjustments to SP AusNet's forecast can be found in table 8.31. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Overhead line replacement

SP AusNet proposed $105.3 million ($2010) in the forthcoming regulatory control period for the replacements of overhead lines. SP AusNet stated that the primary drivers of expenditure for this category were for over head conductors and cross arms replacements. The driver for conductor replacements appears to be bushfire risks.

With regard to the modelling presented, SP AusNet outlined a probabilistic age-based replacement scenario. In its investigation, for cross arm replacements, Nuttall Consulting and the AER noted[258] that SP AusNet altered its replacement criteria in the last regulatory control period and this may have affected or elevated the cross arm replacement rate in the current regulatory control period. Given the catch up in expenditure in the later years of the current regulatory control period as a result of the change in the assessment criteria, Nuttall Consulting reasoned[259] that the replacement levels should return to normal levels in the forthcoming regulatory control period. Based upon the above, the AER considers that Sp AusNet’s expenditure forecast does not reflect its future replacement needs.

The AER considered Nuttall Consulting's view but considers however that the recent 2009 experience of bushfires in Victoria demonstrates that a case can be made for enhanced expenditure on conductor replacement. For this proposed expenditure the AER considers it unlikely that historical expenditure alone is the best guide to the efficient level of capex.

To establish an appropriate allowance for this activity the AER has conducted further analysis of the SP AusNet's proposal. SP AusNet proposed to replace approximately 2,000 km of targeted conductors by 2015.[260] The AER though has seen evidence that the Victorian DNSPs have been successful in their asset life extension work elsewhere which casts doubt on whether the proposed 51.4 year life for steel conductors is pessimistic. The AER therefore has adopted a longer asset life of 60 years for steel conductors and accepts SP AusNet's proposed asset life for copper conductors. In consultation with Nuttall Consulting the AER has modelled the estimated quantity of overhead conductor to be replaced in the forthcoming regulatory control period. To these volume estimates the AER has applied on a pro–rata basis the historical costs of undertaking this activity.

As noted in the SP AusNet analysis, Nuttall Consulting found that 95 per cent of the justification for enhanced expenditure for conductor replacements was related to bushfire risk. The AER acknowledges Nuttall Consulting’s concern that SP AusNet may be unable to adequately target the conductors to be replaced so as to address this

258 SP AusNet, *AMS 20-57 crossarms*, p. 10, *Timber crossarms replacement forecast, Email from SP AusNet to AER's information request 15/04/2010 and 16/04/2010*.

259 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 237-238.

260 SP AusNet, *Electricity Distribution Network Conductor*, p. 18, *Conductor PV analysis*.

specific risk. However, the AER believes that is reasonable to expect that with appropriate application of internal knowledge as to the status and condition of their assets SP AusNet will be able to achieve at least 80 per cent accuracy. Therefore, the AER's view of the efficient level of capex has been adjusted accordingly.

For the reasons discussed above, the AER is not satisfied that the forecast expenditure for the overhead line replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of SP AusNet would require to achieve the capex criteria including the capex objectives. The AER's adjustments to SP AusNet's forecast can be found in table 8.31. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2

Recoverable works

SP AusNet proposed $10.4 million ($2010) in the forthcoming regulatory control period for its recoverable works program.

The AER notes that the historical expenditure for this function code was allocated under the recoverable works special projects code under the customer connections. The AER has reviewed the information provided by SP AusNet and considers that the expenditure proposed by SP AusNet were recurrent tasks that are currently allocated to other function codes. As the basis and justification for the expenditure of this function was unclear, the AER was not satisfied that this forecast is prudent. Consequently, based on the information provided by SP AusNet, Nuttall Consulting and its own analysis, the AER is not satisfied that the forecast expenditure for the recoverable works program reasonably reflects the efficient costs that a prudent operator in the circumstances of SP AusNet would require to achieve the capex criteria including the capex objectives. The AER agrees with Nuttall Consulting[261] that, assuming that similar works in the current regulatory control period have been captured in other function codes, the allowance for the forthcoming regulatory control period should already be captured in those projects. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

AER conclusion

For the reasons discussed, and as a result of the AER’s consideration of SP AusNet's regulatory proposal, Nuttall Consulting’s report, other material and the capex factors, the AER is not satisfied SP AusNet's forecast reasonably reflects the capex criteria, including the capex objectives. In coming to this view the relevant capex factors which the AER has specifically taken into account in assessing the forecast RQM capex include:

- benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period[262]
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods.[263]

[261] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 243.
[262] NER clause 6.5.7(e)(4). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

The AER considers that reducing SP AusNet's RQM forecast capex by the amounts shown in table 8.31 is the minimum adjustment necessary for it to be satisfied it reasonably reflects the capex criteria, including the capex objectives.

Table 8.31 AER conclusion on RQM capex for SP AusNet ($’m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	71.4	80.4	76.5	67.4	57.5	353.2
Less function code adjustments						
OH line replacements	9.2	6.4	7.3	2.6	0.2	25.7
ZSS - plant replacement	13.8	25.2	17.4	14.0	5.8	76.2
Recoverable works	2.1	2.1	2.1	2.1	2.1	10.4
Total adjustments	25.1	33.7	26.8	18.7	8.1	112.3
Total	**46.4**	**46.7**	**49.7**	**48.7**	**49.4**	**240.9**

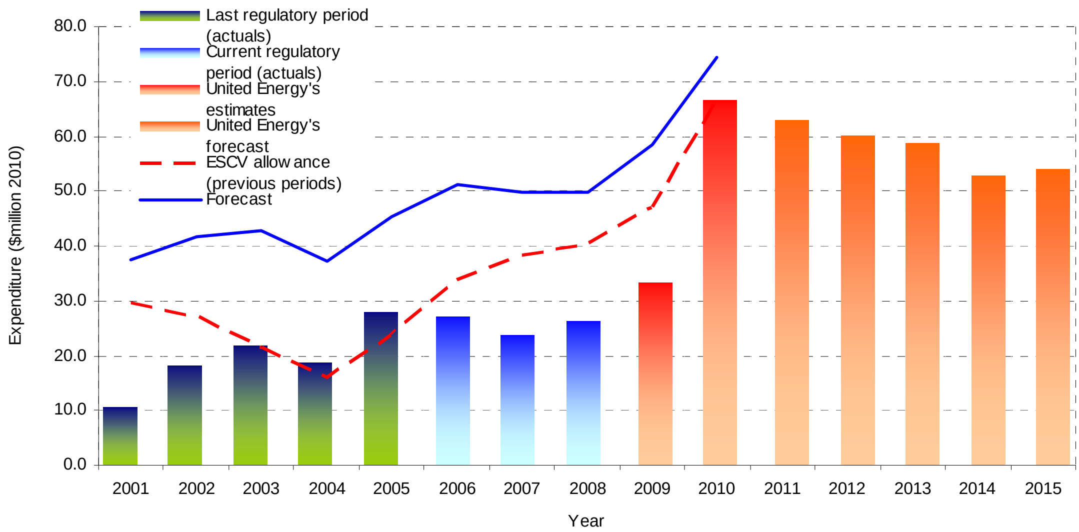
United Energy

United Energy proposed a RQM capex allowance of $277.2 million ($2010) for the forthcoming regulatory control period. United Energy's proposal highlighted a need for capex to be raised significantly in the forthcoming regulatory control period to replace ageing assets and to also better manage extreme weather conditions.[264] Figure 8.11 illustrates United Energy's RQM capex for the previous, current and forthcoming regulatory control periods. Figure 8.11 also includes United Energy's forecasts and ESCV allowance for the two previous regulatory control periods.

[263] NER clause 6.5.7(e)(5). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

[264] United Energy Distribution, *Asset Management Plan 200–16*, p. 14.

Figure 8.11 United Energy RQM capex — historical and proposed ($'m, 2010)



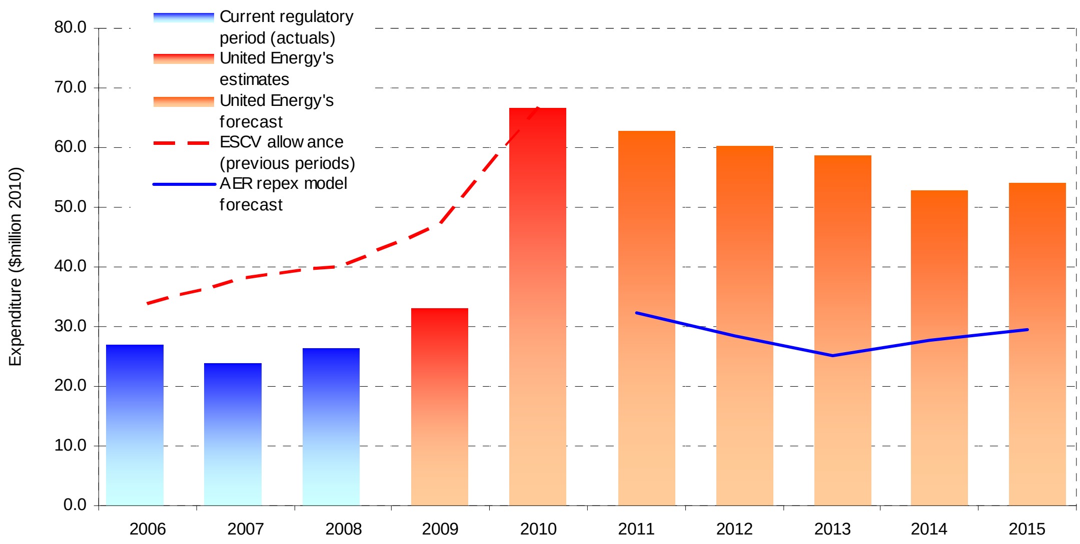
Source: RIN templates. These numbers are fully absorbed as historical allocations were not available.

Figure 8.11 demonstrates that United Energy has:

- consistently forecast a higher level of expenditure than what was required
- a tendency to underspend its RQM capex allowance.

The AER has applied United Energy's historical asset data to its repex model and the AER's forecast for United Energy is illustrated in figure 8.12.

Figure 8.12 AER's forecast on RQM capex for United Energy ($'m, 2010)



Source: RIN templates and AER's repex model. These numbers are fully absorbed as historical allocations were not available.

The AER has reviewed the information provided by United Energy in support of its forecast RQM allowance, including that associated with the ageing of its networks and the purported effects of climate change on its networks in the forthcoming regulatory control period.

United Energy commissioned AECOM to assess the reasonableness of its asset management plan. The AER acknowledge AECOM's findings. However the AER considers that in order to draw any conclusions from the RQM forecast, a rigorous evaluation of the model (specifically the PB model) and inputs and assumptions would be required. The AER was unable to ascertain the level of analysis taken by AECOM in this process from the report. The AER also notes that for replacement capex, no economic analysis was presented by AECOM to demonstrate the prudence and efficiency of the proposed increase.[265]

The AER also notes that United Energy has relied on the AECOM's report on climate change to justify the deterioration of its assets. However, the AER does not consider the findings contained within the AECOM report or the methodology used, to be sufficiently robust to be used as a justification for such a considerable step change in expenditure. The AER's assessment of the AECOM report can be found in section 8.6.4.

The AER notes that United Energy is in the process of transitioning from its current to new business model. Furthermore United Energy's forecast RQM capex is comprised of a detailed ‘bottom-up’ build in relation to both the internal and outsourced functions. The AER has assessed United Energy's forecasts and its findings are outlined below. Where the AER has made adjustments to United Energy's forecasts, the basis for these adjustments were in relation to:

- the level of replacement required in United Energy’s networks
- the justification provided to substantiate United Energy's claim for an increase in the capex allowance

It should be noted also that the AER’s considerations and adjustments were in relation to the expenditure forecasts at the function code level and not in relation to United Energy’s new outsourcing contract.

Pole top structures

United Energy proposed $92.7 million ($2010) for the forthcoming regulatory control period to instigate a pro-active replacement program aimed at replacing ageing wooden cross arms and to mitigate pole fire risks.[266]

United Energy's forecast for its cross arms replacement program was based on the output of the PB replacement model. The AER has reviewed the output of the PB model and acknowledges that it may be a useful tool for forecasting asset replacement. However, the output derived from any model is largely dependent on the

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265 AECOM, *United Energy Distribution Asset Management Plan Review*, pp. 11–26.

266 United Energy Distribution, *UE 4356-103 life cycle management plan pole to structures*. p. 7,*Asset Management Plan 2009-16*, p. 168.

sensitivity of input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted. Given United Energy's:

- internal practices of replacing assets on condition[267]
- limited success in accurately forecasting its replacement needs using the same model since 2000
- actual expenditure compared to forecasts

the AER considers that United Energy's expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program, with the risk remaining constant, the rationale for the $66.7 million increase expenditure was not apparent. United Energy stated that the volume forecast of the PB model was in line with the historical notification rates. However, the AER also notes and agrees with Nuttall Consulting[268] that these rates alone do not fully justify the magnitude of the ramp up in United Energy's proposed expenditure. Furthermore, Nuttall Consulting was concerned with United Energy's definition of average life and replacement life.[269]

Having reviewed United Energy's forecast, the AER agrees with Nuttall Consulting that United Energy has not adequately demonstrated that the model assumptions behind its forecasts are suitable for enabling a bottom-up build that is a reasonable estimation of overall prudent and efficient expenditure. In this regard, the AER does not consider that United Energy has demonstrated that rigorous approaches have been applied to calibrate the model for this purpose. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.

Regarding the bushfire mitigation expenditure the underlying reasons put forward for this ongoing program appears to be known historical issues, risks and/or a change in business practices, which are currently tolerated and managed. The AER considers this new program revolve around internal decisions as to the appropriateness of a process to address known concerns. While the AER agrees that that expenditure should be allocated to mitigate the threat of bush fires, United Energy has not adequately demonstrated why it cannot manage the existing programs within the current level of expenditure. Nuttall Consulting also shared the same concerns regarding this proposal[270] and it recommended[271] an allowance based on historical the historical trend with some allowance for the ageing of the network.

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267 United Energy Distribution, *UE 4356-103 life cycle management plan pole to structures. Asset Management Plan 2009–16, Crossarm Replacement Age Analysis.*

268 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 265.

269 With time, network assets age and deteriorate and, if not replaced, may fail, resulting in a deteriorating level of service reliability and quality. As the age of the asset is a major factor in determining optimal replacement timing, any overestimation of the asset's age profile may lead to a higher forecast in replacements.

270 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 265-266.

271 ibid., p. 265.

Specifically, United Energy:

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing
- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, United Energy has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the pole top replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of United Energy would require to achieve the capex criteria including the capex objectives. The AER's adjustments to United Energy's forecast can be found in table 8.32. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Zone substation

United Energy's expenditure forecast for transformers and circuit breaker replacements totals $31.1 million ($2010) over the forthcoming regulatory control period.

For transformers, United Energy has used the various condition tests results to assess the overall condition of transformers. These test results were then used to determine which transformers should be targeted for replacement.

For the circuit breakers, a risk assessment has been performed to prioritise circuit breaker types for replacement. This assessment accounts for a number of factors; including the condition, age, performance and operational aspects of the circuit breaker type.

For both transformers and circuit breakers, engineering judgement was then used to develop the replacement program, based upon the other considerations for example, augmentation requirements and other replacement needs.

In relation to zone substation transformers, the AER notes Nuttall Consulting's views regarding the conditions of transformers and their remaining life, particularly the accuracy of United Energy's model in predicting the degree of polymerisation.[272]

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[272] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 267–268. The primary test information for replacement timing however concerns the condition of the

With regard to HV circuit breaker replacements, various factors, including risks, were used to determine the prioritisation of replacements. The AER notes Nuttall Consulting's concerns regarding the weightings that were applied to the various factors to determine the resulting prioritisation. Furthermore, Nuttall Consulting concluded that United Energy's risk assessment is quite high-level, and does not allow risks to be readily compared from one element to another. As risk is a major factor in determining optimal replacement timing, the AER is concerned with the nature in which some of these factors were being applied.

Regarding switchgear, United Energy was unable to demonstrate to Nuttall Consulting's satisfaction that its proactive replacement program was reasonable.[273]

The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved.

Specifically, United Energy:

- has not demonstrated an underlying need for a step increase in investment
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing
- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, United Energy has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the zone substation replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of United Energy would require to achieve the capex criteria including the capex objectives.

Given the issues highlighted above, the AER agrees with Nuttall Consulting's assessment and advice that the forecasts for this function code:

- are not reasonable
- only to only allow for a RQM capex allowance that reflects historical trends with some allowance for the ageing of the network.[274]

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insulation material. The degradation of the condition through time is forecast, based upon its existing condition and loading. This calculation predicts the strength of the insulation material (that is, in the form if its degree of polymerisation (DP)) and determines the replacement time, based upon standard industry criteria.

273 ibid., p. 268.

The AER's adjustments to United Energy's forecast can be found in table 8.32. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Overhead lines replacement

United Energy proposed $16.7 million ($2010) in the forthcoming regulatory control period to instigate a pro-active replacement program aimed to replace steel and copper conductors which are in poor condition and approaching the end of their service life.[275]

United Energy's forecast for its conductor replacement program was based on the output of the PB replacement model. The AER has reviewed the output of the PB model and acknowledges that it may be a useful tool for forecasting asset replacement. However the output derived from any model is largely dependent on the sensitivity of input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted. Given United Energy's:

- internal practices of replacing assets on condition[276]
- limited success in accurately forecasting its replacement needs using the same model since 2000
- its actual expenditure compared to forecasts

the AER considers that United Energy’s expenditure forecast does not reflect its future replacement needs. Furthermore, given the recurrent nature of the program, with the risk remaining constant, the rationale for the $15.6 million increase expenditure was not apparent.

Having reviewed United Energy's forecast, the AER agrees with Nuttall Consulting that United Energy has not adequately demonstrated that the model assumptions behind its forecasts are suitable for enabling a bottom-up build that is a reasonable estimation of overall prudent and efficient expenditure. In this regard, the AER does not consider that United Energy has demonstrated that rigorous approaches have been applied to calibrate the model for this purpose. The AER also notes that this modelling exercise is undertaken principally to support the regulatory proposal but, in practice more detailed review and testing of assets will occur prior to any replacements being approved. Nuttall Consulting also shared the same concerns[277] regarding this proposal and it recommended[278] that the proposed expenditure not be supported in the forthcoming regulatory control period.

Specifically, United Energy:

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274 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 268.
275 United Energy Distribution, *Asset Management Plan 2009–16*, p. 18.
276 United Energy Distribution, *UE 4356-1.04 Connector and Conductor Life Cycle Management Plan*, p. 10. *Asset Management Plan 2009–16*, p. 168.
277 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 270.
278 ibid., pp. 270–271.

- has not demonstrated an underlying need for a step increase in investment nor has it provided an economic justification (cost benefit analysis including options analysis)
- has not demonstrated why it cannot manage existing programs and associated risks within the current level of expenditure and existing practices, as it is currently doing
- has not quantified the proposed benefits and outcomes for customers that will be achieved by this proposal
- has not adequately demonstrated how its engineering judgements have been translated into an increase in expenditure. Specifically, United Energy has not established a clear link between its use of engineering judgement and economic efficiency.

For the reasons discussed above, the AER is therefore not satisfied that the forecast expenditure for the overhead line replacement function code reasonably reflects the efficient costs that a prudent operator in the circumstances of United Energy would require to achieve the capex criteria including the capex objectives. The AER's adjustments to United Energy's forecast can be found in table 8.32. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

Reliability

United Energy's expenditure forecast for its reliability program totals $57.9 million ($2010) over the forthcoming regulatory control period. The drivers for this forecast appear to relate to meeting the reliability targets given expected worsening weather conditions.[279] United Energy stated the large portion of this work covers the installation of high voltage aerial bundle conductors and automatic circuit reclosers (presumably for the replacement of bare conductors for reliability and fire mitigation reasons), and the installation of harmonic filters for power quality reasons.[280]

The AER agrees with Nuttall Consulting that the detailed justification[281] for the projects in this category were not clear, particularly with respect to their impact on reliability in the context of the significant increases in expenditure proposed elsewhere. However, assuming that the matters affecting reliability in the current regulatory control period are largely similar to those in the next (that is, ‘business as usual’) and in the absence of a more detailed and quantitative justification for the expenditure increase, the AER consider that an allowance based upon the historical level is reasonable.[282]

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279 United Energy Distribution, *Asset Management Plan 2009–16*, p. 19.
280 United Energy Distribution, *Final 5 year capex plan (attachment B5 network plan).*
281 United Energy Distribution, *UE 4356-107 Automatic Circuit Reclosers Life Cycle Management Plan, UE_4356-122, Bushfire Mitigation Life Cycle Management Plan, UE 4356-1.04 Connector and Conductor Life Cycle Management Plan.*
282 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 272–273.

Consequently, based on the information provided by United Energy, Nuttall Consulting and its own analysis, the AER is not satisfied that the forecast expenditure for this function code reflects the efficient costs that a prudent operator in the circumstances of United Energy would require to achieve the capex criteria including the capex objectives. The AER's adjustments to United Energy's forecast can be found in
table 8.32. In assessing the allowance for this program, the AER has had regard to the capex factors as outlined in section 8.9.2.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of United Energy's regulatory proposal, Nuttall Consulting's report, other material and the capex factors, the AER is not satisfied United Energy's forecast reasonably reflects the capex criteria, including the capex objectives. In coming to this view the relevant capex factors which the AER has specifically taken into account in assessing the forecast RQM capex include:

- benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period[283]
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods.[284]

The AER considers that reducing United Energy's RQM forecast capex by the amounts shown in table 8.32 is the minimum adjustment necessary for it to be satisfied it reasonably reflects the capex criteria, including the capex objectives.

Table 8.32 AER conclusion on RQM capex for United Energy ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Proposed	60.6	58.3	56.5	50.5	51.2	277.2
Less function code adjustments						
OH line replacement	2.2	2.7	2.9	3.2	4.3	15.2
Sub T installation replacement	4.4	4.6	4.9	3.9	2.6	20.4
Pole tops replacement	12.3	14.4	15.7	10.3	10.0	62.6
Reliability maintained (performance)	10.1	8.7	8.3	6.1	5.6	38.9
Total adjustments	29.0	30.3	31.8	23.5	22.4	137.1
Total	**31.6**	**28.0**	**24.7**	**27.0**	**28.8**	**140.1**

283 NER clause 6.5.7(e)(4). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

284 NER clause 6.5.7(e)(5). Please refer to section 8.9.2 for further details of the AER's application and considerations of the capex factors.

8.10 Environmental, Safety and Legal

Introduction

This section focuses on capital expenditure relating to compliance with Environmental, Safety and Legal requirements and obligations.

The Victorian DNSPs have applied the ESCV Guideline No.3 (Guideline 3) to allocate assets to the various capex categories. Guideline 3 defines the Environmental, Safety and Legal cost category as:

> Capital expenditure to meet environmental, safety and legal obligations.[285]

Approach

In assessing and determining whether each of the Victorian DNSPs' proposed Environmental, Safety and Legal capex forecast and the AER's estimate of the required Environmental, Safety and Legal capex reasonably reflects the capex criteria, the AER has had regard to the capex factors, as relevant. Specifically, the AER's analysis of Environmental, Safety and Legal capex takes into account:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period. Appendix I to this draft decision sets out the AER's analysis which benchmarks the Victorian DNSPs against interstate DNSPs
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods. The AER has compared the actual Environmental, Safety and Legal capex incurred in the current and previous regulatory control periods with the corresponding ESCV allowances. The observed trends in actual capex have been considered in the AER's estimate of the required capex for the forthcoming regulatory control period
- the respective prices of operating and capital inputs. Appendix K to this draft decision sets out the AER's analysis of the costs escalators with respect to the Victorian DNSPs’ expenditure proposals
- the substitution possibilities between operating and capital expenditure. The DNSPs' allocation of costs to Environmental, Safety and Legal capex (having regard to their respective capitalisation policies and Guideline 3) has been considered in the AER's estimate of the required capex for the forthcoming regulatory control period.

Further, the AER has examined whether the DNSPs' proposals are in accordance with good industry practice, consistent with achieving the lowest sustainable cost of delivering services, including whether:

- there is a justifiable need for the proposed capex

[285] Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 56.

- the DNSP objectively and competently analysed the investment to a standard that is consistent with good industry practice

- the proposed projects align with the DNSP's strategic capex plans and policies.

In considering the DNSPs' proposals, the AER also considered:

- materiality—the cost associated with the Environmental, Safety and Legal capex as a proportion of the total capex and the cost associated with the DNSPs' proposed projects as a proportion of the total Environmental, Safety and Legal capex

- timing of the proposed expenditure—the drivers of any changes in timing and the processes or systems to ensure prudent decision-making. Further, any economic analysis which clearly demonstrates the need to undertake the proposed projects in the forthcoming regulatory control period

- variations in project costs and scope from original estimates—this provides insight into the governance and business practices for undertaking capital projects and how cost-estimating processes incorporate feedback from specific experience.

Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed capex is set out at table 8.33 below.

Table 8.33 Victorian DNSPs' proposed capex—environmental, safety and legal ($m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	7.0	3.6	3.2	3.2	3.0	3.0	16.0	128
Powercor	35.6	12.9	8.7	9.8	8.9	7.8	48.2	35
Jemena	25.8	4.9	7.7	6.0	4.4	3.9	27.0	4
SP AusNet	72.9	22.8	19.4	22.6	16.0	13.9	94.9	30
United Energy	49.0	15.6	9.1	11.1	7.9	7.4	51.1	4
Total	**190.3**	**59.8**	**48.1**	**52.8**	**40.3**	**36.2**	**237.1**	**25**

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

The Victorian DNSPs have identified:

- ongoing compliance requirements with the Victorian Environment Protection Authority (EPA) policies in relation to noise levels generated at zone substations, containment of oil in zone substations and asbestos management

- changes effective as at 1 January 2010 as foreshadowed in the *Electricity Safety Amendment Act 2007*, including introduction of a compulsory Electricity Safety Management Scheme

as the main drivers of the increase in expenditure in this category from the current regulatory control period into the forthcoming regulatory control period.

Summary of submissions

The EUCV submitted that it is an implicit requirement for the Victorian DNSPs to clearly state the changes to the external obligations which justify the forecast expenditure increases.[286]

Consultant review

Nuttall Consulting compared the DNSPs' proposals for the Environmental, Safety and Legal capex category in the forthcoming regulatory control period with the actual capex for the 2006–2008 period. The 2006–2008 period was used because actual audited data was available for these years and Nuttall Consulting considered that the DNSPs have historically estimated higher expenditure for the remaining years of a regulatory control period than has actually been required.[287]

The proposed increases are set out at table 8.34 below.

Table 8.34 Victorian DNSPs' proposed capex increases—environmental, safety and legal

	Proposed increase (per cent)
CitiPower	160
Powercor	50
Jemena	12
SP AusNet	107
United Energy	22
Victoria	61

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 69.

Nuttall Consulting considered both the Victorian DNSPs' proposed increases and their historic capex trends for the Environmental, Safety and Legal capex category. It then

[286] Energy Users Coalition of Victoria, *Australian Energy Regulator Victorian Electricity Distribution Electricity Reset Applications from CitiPower, Jemena, Powercor, SP AusNet and United Energy: A response by Energy Users Coalition of Victoria*, February 2010, p. 26.

[287] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 25.

targeted its review to DNSPs where the proposed capex significantly increased above historical trends. Therefore, in the Environmental, Safety and Legal capex category, Nuttall Consulting's review focussed on the CitiPower, Powercor, SP AusNet and United Energy proposals.

In the case of SP AusNet, Nuttall Consulting noted that a number of programs for 'pre-emptive replacement' based on age/condition of assets had been included in the Environmental, Safety and Legal capex category. These programs (including associated proposed expenditures) were transferred from the Environmental, Safety and Legal capex category to the Reliability and Quality Maintained capex category.[288]

Nuttall Consulting considered that the DNSPs had broadly categorised the Environmental, Safety and Legal capex project drivers as being either:

- an existing/continuing obligation or regulation or
- a new or changed obligation or regulation.

In the case of the ‘existing/continuing obligation and regulation’ drivers, Nuttall Consulting considered the Victorian DNSPs did not provide sufficient evidence supporting an increase above current expenditure levels.

Nuttall Consulting did note however that the majority of the ‘new or changed obligation or regulation’ drivers related to the DNSPs’ respective Electricity Safety Management Schemes and to bushfire management programs.

Issues and AER considerations

Table 8.35 below sets out the DNSPs' proposed expenditure in this cost category for the forthcoming regulatory control period.

Table 8.35 Victorian DNSPs’ proposed 2011–15 capex—environmental, safety and legal ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
2011–15 proposed expenditure	16.0	48.2	27.0	94.9	52.2	**238.2**
Proportion of total gross direct capex (per cent)	1.7	3.1	4.8	7.8	5.7	**4.6**

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

288 Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 224, 241, and 243.

The Victorian DNSPs have applied Guideline 3 to allocate assets to the various capex categories. Guideline 3 defines the Environmental, Safety and Legal cost category as:

> Capital expenditure to meet environmental, safety and legal obligations.[289]

The projects proposed by the Victorian DNSPs are summarised in table 8.36 below.

Table 8.36 Victorian DNSPs' proposed capex projects—environmental, safety and legal

	Proposed projects
CitiPower	Noise control, containment and drainage of oil in substations, asbestos management
Powercor	Noise control, containment and drainage of oil in substations, asbestos management, bushfire mitigation, managing power line easements in Victorian National Parks
Jemena	Substation security, non-preferred service replacement, conductor replacement, oil containment, installation of neutral earthing resistor and ground fault neutralisers, on-going works correcting identified instances of non-compliance with the *Electricity Safety (Network Asset) Regulations 1999*
SP AusNet	Oil containment, conductor replacement, cross-arm and MV insulator replacement, neutral screened services replacement, fuse replacement, asbestos removal, OHS-related replacement of current transformers, disconnectors and silicon carbine gap arrestors
United Energy	Removal/replacement of equipment containing PCBs, prevention of oil contamination in the event of a leaking transformer, asbestos management, noise abatement, replacement of neutral screened overhead services, installation of ground fault neutralisers in zone substations

Source: CitiPower Regulatory Proposal, Powercor Regulatory Proposal, Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal, United Energy Regulatory Proposal.

Each DNSP has allocated project costs to this capex category on the basis of its assessment of the main project driver in the context of its understanding and interpretation of the Guideline 3 definition. Given that a project may have multiple drivers, DNSPs must exercise judgement to determine the main project driver and thereby allocate the project to a capex category. For example, allocation may be different across the DNSPs, as determined by whether the main driver for the project is 'replacement due to age/condition', 'replacement due to safety concerns' or 'works to meet Australian Standards'. As a result, the AER notes that capex associated with Environmental, Safety and Legal activities has been allocated by the DNSPs to one or more of the Environmental, Safety and Legal, Reinforcement, Reliability and Quality Maintained and Non-network–Other capex categories.

The AER also notes that the Victorian DNSPs have proposed bushfire mitigation projects in both the Environmental, Safety and Legal and Reliability and Quality

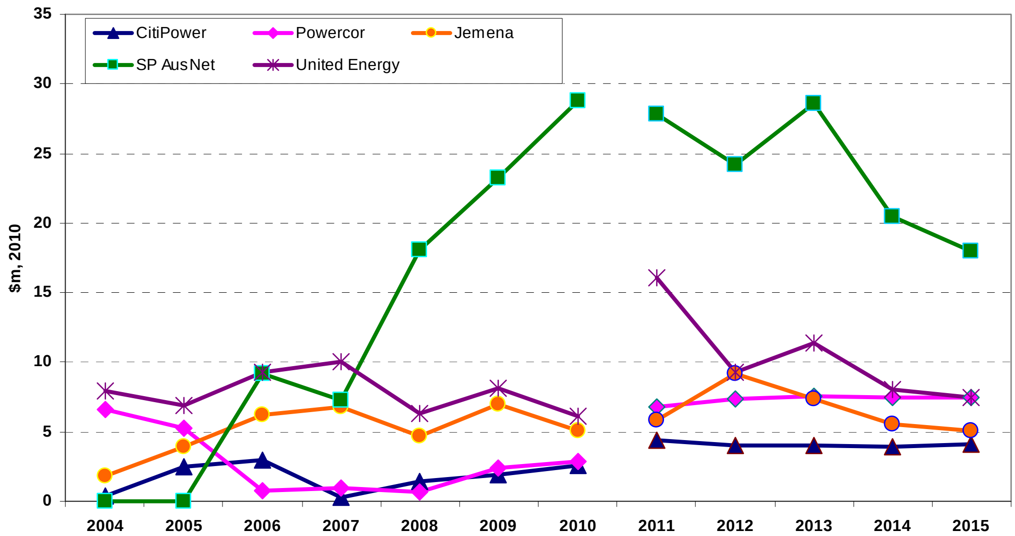
[289] Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 56.

Maintained capex categories. Therefore, in the case of SP AusNet, the AER agrees with Nuttall Consulting that the programs for 'pre-emptive replacement' based on age/condition of assets should be reallocated from the Environmental, Safety and Legal capex category to Reliability and Quality Maintained capex category. As a result, these projects (and associated expenditures) have not been assessed in the Environmental, Safety and Legal capex category. The projects have been assessed in the Reliability and Quality Maintained capex category.

Having adjusted SP AusNet's proposed Environmental, Safety and Legal capex as described above, the AER has assessed the Victorian DNSPs' proposals on a basis similar to that used by the ESCV in determining the benchmark allowances for the 2006–2010 regulatory control period. As discussed at 8.6.2, AER analysis indicates that the DNSPs appear to spend significantly less than forecast and DNSP actual capex tends to follow a gradually increasing trend. Therefore, the historical underlying trend in capex has been used as the starting point for assessing the reasonableness of each DNSP's capex proposal.

Figure 8.13 below illustrates the expenditure trend in this cost category.

Figure 8.13 Victorian DNSPs' 2004–2015 capex—Environmental, Safety and Legal ($m, 2010)



Note: Capex in this figure is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.
2004-2008 data is actual capex, 2009-2015 is forecast capex.

Source: CitiPower Regulatory Proposal, RIN template 2.1, Powercor Regulatory Proposal, RIN template 2.1, Jemena Regulatory Proposal, RIN template 2.1, SP AusNet, Regulatory Proposal, RIN template 2.1, United Energy Regulatory Proposal, RIN template 2.1.

The AER considers the variability of the capex amounts in this category relates to the variation in expenditure priorities on the basis of each DNSP's assessment of its relevant safety and compliance risks. Therefore, the historic trend cannot completely determine future requirements should the Victorian DNSPs significantly alter their approach to the management of compliance risks. However, the historic trend capex should include expenditures for changes which have eventuated in the current regulatory control period.

In identifying the underlying trend, the AER has considered data for 2004 to 2008 inclusive, from the current and previous regulatory control periods. The 2009 and 2010 data provided by the DNSPs is forecast data and therefore not considered to be part of the historical trend.

Table 8.37 below sets out the expenditure in this cost category for the current regulatory control period.

Table 8.37 Victorian DNSP 2006–10 capex—environmental, safety and legal ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
ESCV benchmark allowance	92.5	92.5	22.0	116.5	62.3
2006–10 expected expenditure	9.2	42.7	29.7	86.5	40.0
Variance (per cent)	– 90.0	– 53.8	35.0	– 25.8	– 35.8

Note: Capex in this table is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN template 5.1, Powercor Regulatory Proposal, RIN template 5.1, Jemena Regulatory Proposal, RIN template 5.1, SP AusNet, Regulatory Proposal, RIN template 5.1, United Energy Regulatory Proposal, RIN template 5.1.

The reasons for the variations shown at table 8.37 are summarised in table 8.38 below.

Table 8.38 Victorian DNSP capex—environmental, safety and legal—explanation of variation between ESCV benchmark allowance and 2006–10 expenditure

	Explanation of variation
CitiPower	No explanation provided by DNSP
Powercor	No explanation provided by DNSP
Jemena	No explanation provided by DNSP
SP AusNet	Have met all environmental and security and environmental obligations
United Energy	No explanation provided by DNSP

Source: CitiPower Regulatory Proposal, Powercor Regulatory Proposal, Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal, United Energy Regulatory Proposal.

The AER considers it appropriate to allow adequate funding to achieve safety and other regulatory and legislative obligations while managing the network in accordance with good electricity industry practice. Given that similar issues and cost drivers were raised in support of the capex proposals for the current and previous regulatory control periods, the AER considers that the actual/out-turn expenditure represents the efficient capex amount.[290] That is, since each DNSP retains discretion to prioritise its work program and allocate its resources to meet customer requirements while managing and operating its network in accordance with good electricity industry practice, each DNSP has over/underspent relative to the ESCV benchmark allowance on the basis of its own assessments of whether it is efficient to do so.

The AER notes that Guideline 3 does not specify or limit the obligations which should be considered in this cost category. Although the Victorian DNSPs have provided lists of legislation and regulations, they have not specified the changes in the nature of the associated obligations which have resulted in the forecast increases in expenditure.

The AER notes the DNSPs' proposals have focussed on:

- compliance with Victorian Environmental Protection Authority (EPA) environment protection policies. Specifically, noise mitigation, oil containment and drainage and handling and disposal of asbestos

- safety obligations under the *Electrical Safety Act 1998* (Vic) and associated regulations. In particular, changes arising from the *Electrical Safety Amendment Act 2007* (Vic).

In assessing the Victorian DNSPs' proposed capex for the forthcoming regulatory control period, the AER sought to understand the reasons for the variation from historical capex trends. The AER requested additional supporting information from each DNSP, including cost drivers, changes in functions or legislative obligations and available information on projects included in the DNSPs' 'bottom-up' capex forecast cost build up. The DNSPs provided their indicative project lists to the AER. They explained they had relied upon technical engineering experience to derive the proposed project cost estimates because detailed business cases were typically prepared closer to the date of project implementation. Therefore, the AER considered whether the proposed indicative projects were linked to larger documented strategies/programs of work including an economic assessment of the need for the overall work program and the scale and timing of the proposed works.

The AER notes that EPA Victoria and Energy Safe Victoria (ESV) have encouraged businesses to adopt a risk management approach to compliance. Therefore, the AER expected the DNSPs would provide their risk assessments of each proposed compliance initiative. The AER considered whether the Victorian DNSPs had prioritised the need and timing for the proposed compliance programs using risk assessments, including an economic assessment of the costs and benefits of particular courses of action. For example, the DNSPs' proposals include programs of varying length such that some programs would be completed within the forthcoming regulatory control period whereas others have a total program length of 40 years. The AER considers such assessments are appropriate even in circumstances where action

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[290] Essential Services Commission, *Electricity Distribution Price Review 2006–10: Draft Decision,* June 2005, pp. 258–274.
Essential Services Commission, *Electricity Distribution Price Review 2006–10: Final Decision,* October 2006, pp. 299–320.

is mandated by legislation/regulation or by a regulatory body and notes that when there is a change to a legislative obligation, there is typically a transition period for a business to achieve compliance. The AER notes that a risk management approach to compliance allows businesses to assess their obligations and bear compliance risk where they are willing to do so.

The AER considers that the amounts proposed by the DNSPs suggest there has been a step change in their obligations between the current and forthcoming regulatory control periods. The AER considers that the DNSPs have not identified regulatory obligations or requirements that will take effect for the first time in the forthcoming regulatory control period.

CitiPower and Powercor considered their capex forecasts represent amounts necessary to ensure compliance with all applicable environmental, electrical safety, regulatory and other Victorian and national legislative obligations in the forthcoming regulatory control period. They provided summary explanations of projects proposed in this capex category however, these were not linked to any risk assessment in support of an overall works program. CitiPower and Powercor also considered that cost benefit analyses were not relevant where they had deemed works were required to achieve regulatory compliance. The AER does not consider Powercor's anticipated agreement with Parks Victoria will introduce additional obligations as Powercor already manages access to its power line corridors through Parks Victoria lands.

In contrast, Jemena, SP AusNet and United Energy did provide some risk assessment spreadsheets in support of their proposed projects which are summarised in table 8.37. Although the risk assessments confirmed the need to undertake work, there were no associated economic analysis assessing the project scope, cost-benefit and timing.

As the DNSPs are currently complying with their obligations, the associated costs will be reflected in the historical capex trend for this category. The AER sought clarification by ESV regarding the nature of any change in safety compliance risks faced by the DNSPs. The ESV confirmed that the regulatory obligations of the Victorian DNSPs have not altered as a result of the amendments to the Electricity Safety Act 1998 and associated regulations. In particular, there has been no change to the (safety) risks associated with design, construction, operation, maintenance and decommissioning of a supply network owned or operated by a DNSP.[291] Therefore, the AER considers that the DNSPs have not demonstrated that there will be material step changes to their compliance with:

- environmental legislation and regulations, particularly the EPA environment protection policies or
- Victorian safety legislation and regulations.

The AER considers that CitiPower, Powercor, Jemena, SP AusNet and United Energy have not justified the significant capex increase in this cost category from the current to the forthcoming regulatory control period. The AER does not consider the DNSPs have identified any changes in regulatory obligations or requirements in the

[291] AER letter to ESV, 25 March 2010 and ESV letter to AER, 15 April 2010

forthcoming regulatory control period that will materially affect the Environmental, Safety and Legal capex requirement in the forthcoming regulatory control period. Therefore, the AER has rejected the proposed capex amounts and has substituted amounts based on a continuation of the historical expenditure trend in this capex category.

In summary, the AER considers that the project information provided by CitiPower, Powercor, Jemena, SP AusNet and United Energy:

- has not adequately demonstrated how engineering judgements have been translated into a step change in expenditure and, in particular, did not establish a clear link between exercise of judgement and economic efficiency
- has not demonstrated an underlying need for a step increase in investment supported by an economic justification (cost benefit analysis including options analysis)
- has not demonstrated why they cannot manage existing programs and associated risks within the current level of expenditure and existing practices as achieved in the current period—given that they have successfully managed risks to within acceptable parameters in the current regulatory control period
- did not attempt to quantify the benefits and outcomes for customers achieved by the forecast level of investment
- has not demonstrated how the forecasts were a reflection of risk assessments, that is, how the application of the risk management practices and procedures set out in the risk assessments translated into the forecast expenditures.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the information submitted in support of the Environmental, Safety and Legal capex proposal, the AER is not satisfied that the projects proposed by CitiPower, Powercor, Jemena, SP AusNet and United Energy reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods
- the respective prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure

and, where relevant, has made the minimum necessary change to the DNSPs' forecast ESL expenditure.

Table 8.39 below sets out the AER's conclusion on the Victorian DNSPs' proposed expenditure in the Environmental, Safety and Legal capex cost category for the forthcoming regulatory control period.

The AER notes that capex may appear lumpy within a capex category, however, the total capex allowance is not tied to a fixed, project-specific work program. In this regard, the AER notes that although the DNSPs have indicated they have prepared their capex forecasts on a detailed project-by-project basis, and the AER has for the most part assessed expenditure in this way, the AER's conclusions relate to a total forecast capex allowance for this capex cost category.

Table 8.39 AER conclusion on Victorian DNSP 2011–15 capex—environmental, safety and legal ($m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	1.2	1.2	1.2	1.2	1.2	6.0
Powercor	6.7	6.7	6.7	6.7	6.7	33.5
Jemena	5.0	5.0	5.0	5.0	5.0	25.0
SP AusNet	1.1	1.1	1.1	1.1	1.1	5.5
United Energy	8.5	8.5	8.5	8.5	8.5	42.7
Total	**22.5**	**22.5**	**22.5**	**22.5**	**22.5**	**112.7**

Note: Totals may not add due to rounding.

8.11 SCADA and Network Control

Introduction

This section focuses on capital expenditure relating to SCADA and Network Control.

The Victorian DNSPs have stated they have applied Guideline.3 to allocate assets to the various capex categories. Guideline 3 defines the SCADA and Network Control cost category as:

> Expenditure associated with the replacement, installation and maintenance of Supervisory Control and Data Acquisition (SCADA) and network control hardware, software and associated IT systems.[292]

Approach

In assessing and determining whether each of the Victorian DNSPs' proposed SCADA and Network Control capex forecast and the AER's estimate of the required

[292] Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 57.

SCADA and Network Control capex reasonably reflects the capex criteria, the AER has had regard to the capex factors, as relevant. Specifically, the AER's analysis of SCADA and Network Control capex takes into account:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period. Appendix I to this draft decision sets out the AER's analysis which benchmarks the Victorian DNSPs against interstate DNSPs
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods. The AER has compared the actual SCADA and Network Control capex incurred in the current and previous regulatory control periods with the corresponding ESCV allowances. The observed trends in actual capex have been considered in the AER's estimate of the required capex for the forthcoming regulatory control period
- the respective prices of operating and capital inputs. Appendix K to this draft decision sets out the AER's analysis of the costs escalators with respect to the Victorian DNSPs expenditure proposals
- the substitution possibilities between operating and capital expenditure. The DNSPs' allocation of costs to SCADA and Network Control capex (having regard to their respective capitalisation policies and Guideline 3) has been considered in the AER's estimate of the required capex for the forthcoming regulatory control period.

Further, the AER has examined whether the DNSPs' proposals are in accordance with good industry practice, consistent with achieving the lowest sustainable cost of delivering services, including whether:

- there is a justifiable need for the proposed capex
- the DNSP objectively and competently analysed the investment to a standard that is consistent with good industry practice
- the proposed projects align with the DNSP's strategic capex plans and policies

In considering the DNSPs' proposals, the AER also considered:

- materiality—the cost associated with the SCADA and Network Control capex as a proportion of the total capex and the cost associated with the DNSPs’ proposed projects as a proportion of the total SCADA and Network Control capex
- timing of the proposed expenditure—the drivers of any changes in timing and the processes or systems to ensure prudent decision-making. Further, any economic analysis which clearly demonstrates the need to undertake the proposed projects in the forthcoming regulatory control period
- variations in project costs and scope from original estimates—this provides insight into the governance and business practices for undertaking capital projects and how cost-estimating processes incorporate feedback from specific experience.

Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed capex is set out at table 8.40 below.

Table 8.40 Victorian DNSPs' proposed capex—SCADA and network control ($m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	4.5	3.8	3.5	3.6	3.6	3.6	18.1	301
Powercor	6.5	5.9	6.3	6.3	6.1	6.0	30.6	369
Jemena	2.7	0.7	1.0	1.1	0.3	0.0	3.1	16
SP AusNet	15.2	0.6	0.7	1.1	4.1	0.9	7.4	–51
United Energy	0.0	0.0	0.7	3.9	0.0	0.0	4.7	–
Total	**28.9**	**11.0**	**12.3**	**16.1**	**14.1**	**10.6**	**64.0**	**121**

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

Supervisory Control and Data Acquisition (SCADA) and network control expenditure relates to installation of SCADA master stations, Distribution Management System (DMS) field devices, protection and control communications infrastructure and assets such as switches and fault indicators.

Summary of submissions

The AER received no submissions on the SCADA and Network Control capex proposed by the Victorian DNSPs.

Consultant review

Nuttall Consulting compared the DNSPs' proposals for the SCADA and Network Control capex category in the forthcoming regulatory control period with the actual capex for the 2006–2008 period. The 2006–2008 period was used because actual audited data was available for these years and Nuttall Consulting considered that the DNSPs have historically estimated higher expenditure for the remaining years of a regulatory control period than has actually been required.[293]

The proposed increases are set out at table 8.41 below.

[293] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 25.

Table 8.41 Victorian DNSPs' proposed capex increases—SCADA and network control

	Proposed increase (per cent)
CitiPower	703
Powercor	831
Jemena	–34
SP AusNet	–68
United Energy	–
Victoria	106

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p.73.

Nuttall Consulting considered both the Victorian DNSPs' proposed increases and their historic capex trends for the SCADA and Network Control capex category. It then targeted its review to DNSPs where the proposed capex significantly increased above historical trends. Therefore, in the SCADA and Network Control capex category, Nuttall Consulting's review focussed on the CitiPower, Powercor and Jemena proposals.

Nuttall Consulting noted that the Victorian DNSPs did not identify any new or changed regulations or obligations requiring a step change in SCADA and Network Control capex. The primary reason given for the proposed expenditure was to modernise aging systems. Nuttall Consulting also noted that costs included in this category varied among the DNSPs and there was project overlap between the SCADA and Network Control and Non-network–IT capex categories.

Nuttall Consulting considered Jemena's proposed SCADA and Network Control capex to be prudent and efficient, however, it recommended the existing level of expenditure for CitiPower and Powercor because insufficient information was provided to determine whether the proposed projects represented prudent and/or efficient expenditure.

Issues and AER considerations

Table 8.42 below sets out the DNSPs' proposed expenditure in this cost category for the forthcoming regulatory control period.

Table 8.42 Victorian DNSPs' proposed 2011–15 capex—SCADA and network control ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
2011–15 proposed expenditure	18.1	30.6	3.1	7.4	4.7	64.0
Proportion of total gross direct capex (per cent)	1.9	2.0	0.6	0.6	0.5	1.2

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal , RIN templates 2.1 and 3.1, Powercor Regulatory Proposal , RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

The Victorian DNSPs have stated they have applied Guideline 3 to allocate assets to the various capex categories. Guideline 3 defines the SCADA and Network Control cost category as:

> Expenditure associated with the replacement, installation and maintenance of Supervisory Control and Data Acquisition (SCADA) and network control hardware, software and associated IT systems.[294]

The projects proposed by the Victorian DNSPs are summarised in table 8.43 below.

Table 8.43 Victorian DNSPs' proposed capex projects—SCADA and network control

	Proposed projects
CitiPower	Project undertaken jointly with Powercor - installation of SCADA master station, DMS field units and network asset condition monitoring
Powercor	Project undertaken jointly with CitiPower - installation of SCADA master station, DMS field units and network asset condition monitoring
Jemena	Installation of zone substation electronic security system utilising the existing SCADA communications network
SP AusNet	Installation of network control hardware, software and associated IT systems
United Energy	Relocation of control centre

Source: CitiPower Regulatory Proposal, Powercor Regulatory Proposal, Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal, United Energy Regulatory Proposal.

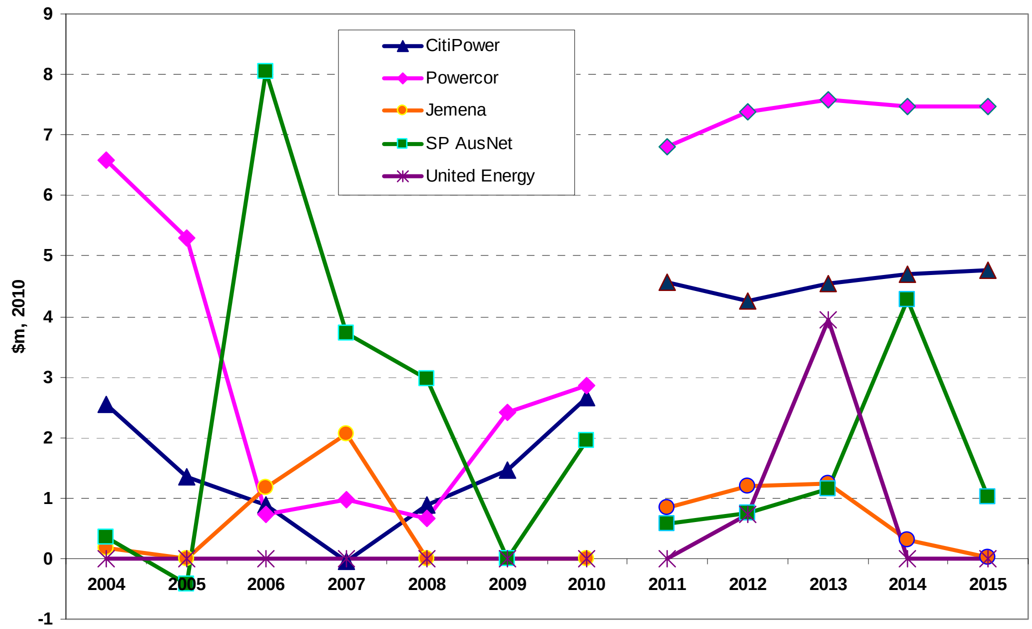
294 Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 57.

Each DNSP has allocated project costs to this capex category on the basis of its assessment of the main project driver in the context of its understanding and interpretation of the Guideline 3 definition. Given that a project may have multiple drivers, DNSPs must exercise judgement to determine the main project driver and thereby allocate the project to a capex category. As a result, the AER notes that capex associated with SCADA and network control activities has been allocated by the DNSPs to one or more of the SCADA and Network Control, Non-network–IT, Reinforcement and Reliability and Quality Maintained capex categories.

The AER has not attempted to reallocate projects across categories to facilitate meaningful comparison of category expenditures across the DNSPs. Instead, the AER has assessed the Victorian DNSPs' proposals on a basis similar to that used by the ESCV in determining the benchmark allowances for the 2006–10 regulatory control period. As discussed at 8.6.2, AER analysis indicates that the DNSPs appear to spend significantly less than forecast and DNSP actual capex tends to follow a gradually increasing trend. Therefore, the historical underlying trend in capex has been used as the starting point for assessing the reasonableness of each DNSP's capex proposal.

Figure 8.14 below illustrates the expenditure trend in this cost category.

Figure 8.14 Victorian DNSPs' 2004–2015 capex—SCADA and network control ($m, 2010)



Note: Capex in this figure is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.
2004-2008 data is actual capex, 2009-2015 is forecast capex.

Source: CitiPower Regulatory Proposal 2009, RIN template 2.1, Powercor Regulatory Proposal, RIN template 2.1, Jemena Regulatory Proposal, RIN template 2.1, SP AusNet, Regulatory Proposal, RIN template 2.1, United Energy Regulatory Proposal, RIN template 2.1.

The AER notes the variability of the capex amounts in this category and considers this relates to the periodic need to upgrade and/or replace assets. That is, while SCADA software may require to be upgraded in 5 years, communications cables and electronic and microprocessor equipment may have up to 40 year lives. As such, the historic trend cannot completely determine future requirements. However, the historic trend capex should include expenditures for changes which have eventuated in the current regulatory control period.

In identifying the underlying trend, the AER has considered data for 2004 to 2008 inclusive, from the current and previous regulatory control periods. The 2009 and 2010 data provided by the DNSPs is forecast data and therefore not considered to be part of the historical trend.

Table 8.44 below sets out the expenditure in this cost category for the current regulatory control period. The AER notes that the DNSPs have underspent in relation the benchmark allowance for the current regulatory control period.

Table 8.44 Victorian DNSP 2006–10 capex—SCADA and network control ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
ESCV benchmark allowance	18.3	18.3	11.2	30.2	–
2006–10 expenditure	5.8	7.6	3. 3	16.7	–
Variance (per cent)	–68.3	–8.5	–70.5	–44.7	–

Note: Capex in this table is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN template 5.1, Powercor Regulatory Proposal, RIN template 5.1, Jemena Regulatory Proposal, RIN templates 5.1, SP AusNet, Regulatory Proposal, RIN templates 5.1, United Energy Regulatory Proposal, RIN templates 5.1.

The reasons for the variations shown at table 8.44 are summarised in table 8.45 below.

Table 8.45 Victorian DNSP SCADA and network control capex—explanation of variation between ESCV benchmark allowance and 2006–10 expenditure

	Explanation of variation
CitiPower	Delayed start to commencement of CitiPower and Powercor joint project to upgrade protection and control communications infrastructure
Powercor	Delayed start to commencement of CitiPower and Powercor joint project to upgrade protection and control communications infrastructure
Jemena	No explanation provided by DNSP
SP AusNet	Allocation of remote SCADA expenditure to sub-transmission and distribution categories and consolidation of SCADA IT platform
United Energy	–

Source: CitiPower Regulatory Proposal and response to SCADA information request, Powercor Regulatory Proposal and response to SCADA information request, Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal p.150, United Energy Regulatory Proposal.

The AER considers it appropriate to allow adequate funding to monitor and control the network so that it can be managed and operated in accordance with good electricity industry practice. Given that similar issues and cost drivers were raised in support of the capex proposals for the current and previous regulatory control periods, the AER considers that the actual/out-turn expenditure represents the efficient capex amount.[295] That is, since each DNSP retains discretion to prioritise its work program and allocate its resources to meet customer requirements while managing and operating its network in accordance with good electricity industry practice, each DNSP has underspent relative to the ESCV benchmark allowance on the basis of its own assessments of whether it is efficient to do so.

In assessing the Victorian DNSPs' proposed capex for the forthcoming regulatory control period, the AER sought to understand the reasons for the variation from historical capex trends. The AER requested additional supporting information from each DNSP, including cost drivers, changes in functions or legislative obligations and available information on projects included in the DNSPs' 'bottom-up' capex forecast cost build up. The DNSPs provided their indicative project lists to the AER. They explained they had relied upon technical engineering experience to derive the proposed project cost estimates because detailed business cases were typically prepared closer to the date of project implementation. Therefore, the AER considered whether the proposed indicative projects were linked to larger documented strategies/programs of work including an economic assessment of the need for the overall work program and the scale and timing of the proposed works.

During the current regulatory control period, CitiPower and Powercor jointly commenced implementation of a new SCADA system platform. Their Network Protection and Control Communications Strategy 2009–14 provides a high level summary of the DNSPs' requirements during this period. However, the AER notes that indicative program costs and benefits are not quantified and there is no economic assessment of the program scope and timing. Further, the majority of the summary explanations of the projects proposed in this capex category did not link the proposed projects to the strategy.

The AER notes the CitiPower and Powercor proposals state that the following activities have commenced in the current regulatory control period and have been proposed to continue in the forthcoming regulatory control period.

- installation of new protection and control communications infrastructure
- migration away from trunk mobile radio software to SCADA
- increased substation monitoring and automation.

The AER considers that CitiPower and Powercor have not justified the significant capex increase in this cost category from the current to the forthcoming regulatory

[295] Essential Services Commission, *Electricity Distribution Price Review 2006–10: Draft Decision,* June 2005, pp. 258–274.
Essential Services Commission, *Electricity Distribution Price Review 2006–10: Final Decision,* October 2006, pp. 299–320.

control period. Therefore, the AER has rejected the proposed capex amounts and has substituted amounts based on a continuation of the historical expenditure trend in this capex category.

Jemena's proposed SCADA and Network Control expenditures relate to integration of an electronic zone substation security system with the SCADA system. The AER notes that the project is part of a larger continuing program consistent with Jemena's strategy to improve security at its zone substations. Therefore, the AER has accepted the inclusion of the proposed capex amounts in the SCADA and Network Control capex category.

SP AusNet proposed expenditures relating to upgrading SCADA master station IT hardware and software. The AER notes that the project was also included in SP AusNet's Information Technology Strategy and, as a result, the project costs were also included in the proposed Non-network–IT capex. Therefore, the AER has rejected the inclusion of the proposed capex amounts in the SCADA and Network Control capex category.

The AER notes that United Energy's proposed capex to fit-out new control room facilities resulting from its decision to 'in-source' the provision of the control room services consistent with its transformed business model. Control room services are currently provided to United Energy by Jemena Asset Management (JAM). Although United Energy has taken steps to move away from its current arrangements with JAM, it has not demonstrated that alternative arrangements necessitating the in-sourcing of control room functions will be in place in the forthcoming regulatory control period. Therefore, the AER has rejected the inclusion of the proposed capex amounts in the SCADA and Network Control capex category.

In summary, the AER considers that the project information provided by CitiPower, Powercor, SP AusNet and United Energy:

- has not adequately demonstrated how engineering judgements have been translated into a step change in expenditure and, in particular, did not establish a clear link between exercise of judgement and economic efficiency

- has not demonstrated an underlying need for a step increase in investment supported by an economic justification (cost benefit analysis including options analysis)

- has not demonstrated why they cannot manage existing programs and associated risks within the current level of expenditure and existing practices as achieved in the current regulatory control period—given that they have successfully managed risks to within acceptable parameters in the current regulatory control period

- did not attempt to quantify the benefits and outcomes for customers achieved by the forecast level of investment.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the information submitted in support of the SCADA and Network Control capex proposal, the AER is:

- not satisfied that the projects proposed by CitiPower, Powercor, SP AusNet and United Energy reasonably reflects the capex criteria, including the capex objectives
- satisfied that the projects proposed by Jemena reasonably reflect the capex criteria, including the capex objectives.

In coming to this view, the AER has had regard to the capex factors:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods
- the respective prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure

and, where relevant, has made the minimum necessary change to the DNSPs' proposals.

Table 8.46 below sets out the AER's conclusion on the Victorian DNSPs' proposed expenditure in the SCADA and Network Control capex cost category for the forthcoming regulatory control period.

The AER notes that capex may appear lumpy within a capex category, however, the total capex allowance is not tied to a fixed, project-specific work program. In this regard, the AER notes that although the DNSPs have indicated they have prepared their capex forecasts on a detailed project-by-project basis, and the AER has for the most part assessed expenditure in this way, the AER's conclusions relate to a total forecast capex allowance for this capex cost category.

Table 8.46 AER conclusion on Victorian DNSP 2011–15 capex—SCADA and network control ($m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	1.0	1.0	1.0	1.0	0.9	4.9
Powercor	2.5	2.5	2.4	2.4	2.3	12.0
Jemena	0.7	1.1	1.1	0.3	0.0	3.2
SP AusNet	0.0	0.0	0.0	0.0	0.0	0.0
United Energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	**4.2**	**4.6**	**4.5**	**3.6**	**3.3**	**20.1**

Note: Totals may not add due to rounding

8.12 Non-network–IT, Non-Network–Other

8.12.1 Non-network–IT capex

Introduction

This section focuses on capital expenditure relating to Non-Network–IT.

The Victorian DNSPs have applied Guideline 3 to allocate assets to the various capex categories. The guideline defines the non-network general assets cost category as:

> Expenditure associated with replacement, installation and maintenance of non-network assets such as, but not restricted to, vehicles, non-operational buildings and non-operational IT systems.[296]

Approach

In assessing and determining whether each of the Victorian DNSPs' proposed Non-Network–IT capex forecast and the AER's estimate of the required Non-Network–IT capex reasonably reflects the capex criteria, the AER has had regard to the capex factors, as relevant. Specifically, the AER's analysis of Non-Network–IT capex takes into account:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period. Appendix I to this draft decision sets out the AER's analysis which benchmarks the Victorian DNSPs against interstate DNSPs

- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods. The AER has compared the actual Non-Network–IT capex incurred in the current and previous regulatory control periods with the corresponding ESCV allowances. The observed trends in actual capex have been considered in the AER's estimate of the required capex for the forthcoming regulatory control period

- the respective prices of operating and capital inputs. Appendix K to this draft decision sets out the AER's analysis of the costs escalators with respect to the Victorian DNSPs' expenditure proposals

- the substitution possibilities between operating and capital expenditure. The DNSPs' allocation of costs to Non-Network–IT capex (having regard to their respective capitalisation policies and Guideline 3) has been considered in the AER's estimate of the required capex for the forthcoming regulatory control period.

Further, the AER has examined whether the DNSPs' proposals are in accordance with good industry practice, consistent with achieving the lowest sustainable cost of delivering services, including whether:

- there is a justifiable need for the proposed capex

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296 Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 57.

- the DNSP objectively and comprehensively analysed the investment to a standard that is consistent with good industry practice

- the proposed projects align with the DNSP's strategic capex plans and policies

In considering the DNSPs' proposals, the AER also considered:

- materiality—the cost associated with the Non-Network–IT capex as a proportion of the total capex and the cost associated with the DNSPs’ proposed projects as a proportion of the total Non-Network–IT capex

- timing of the proposed expenditure—the drivers of any changes in timing and the processes or systems to ensure prudent decision-making. Further, any economic analysis which clearly demonstrates the need to undertake the proposed projects in the forthcoming regulatory control period

- variations in project costs and scope from original estimates—this provides insight into the governance and business practices for undertaking capital projects and how cost-estimating processes incorporate feedback from specific experience.

Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed capex is set out at table 8.47 below.

Table 8.47 Victorian DNSPs’ proposed capex—non-network—IT category ($m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	20.7	8.6	7.6	8.3	11.4	9.0	44.9	117
Powercor	23.2	22.5	19.0	18.7	25.0	19.7	104.7	351
Jemena	44.1	16.9	17.4	13.9	5.2	5.3	58.8	33
SP AusNet	104.4	31.9	37.1	27.1	30.2	16.7	143.0	37
United Energy	9.5	29.2	28.3	18.1	15.9	7.1	98.5	934
Total	**202.1**	**109.0**	**109.5**	**86.0**	**87.7**	**57.7**	**449.9**	**123**

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

This capex category includes assets relating to SCADA and Network Control capex category. It also includes IT infrastructure, distribution systems and corporate and customer information systems.

Summary of submissions

The AER received no submissions on the Non-network–IT capex proposed by the Victorian DNSPs.

Consultant review

Nuttall Consulting compared the DNSPs' proposals for the Non-network–IT capex category in the forthcoming regulatory control period with the actual capex for the 2006–08 period. The 2006–08 period was used because actual audited data was available for these years and Nuttall Consulting considered that each of the DNSPs has historically estimated higher expenditure for the remaining years of a regulatory control period than has actually been required.[297]

The proposed increases are set out at table 8.48 below.

Table 8.48 Victorian DNSPs' proposed capex increases —non-network—IT category

	Proposed increase (per cent)
CitiPower	163
Powercor	358
Jemena	45
SP AusNet	224
United Energy	416
Victoria	206

Source: Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 77

Nuttall Consulting reviewed the Non-network–IT capex proposed by each of the Victorian DNSPs. The review focussed on:

- server IT systems located inside dedicated data centres. These systems comprise hardware and software for enterprise systems including Geographical Information Systems, Customer Information Systems, Outage Management Systems, SAP, and SCADA
- desktop IT systems used by DNSP staff and comprising hardware and software licences
- IT systems supporting the implementation of Advanced Metering Infrastructure (AMI) rollout mandated by the Victorian government.

Nuttall Consulting considered that each DNSP submitted reasonable costs for ongoing upgrades of their desktop IT systems and, therefore, recommended these costs be accepted by the AER.

[297] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, p. 25.

The DNSPs considered they could not anticipate IT requirements for changes brought about by external factors. Nuttall Consulting considered this view was reflected in the DNSPs' detailed IT architecture/strategy documents which did not consider the provision of a flexible architecture able to respond to changing business needs. Nuttall Consulting noted that, in relation to server IT systems, the DNSPs submitted detailed cost justifications and independent project assessment documentation from third party providers.

Nuttall Consulting also investigated whether there was any overlap in project scope between projects proposed in the Non-network - IT capex category and projects included in the separate AER 2009 AMI determination. Nuttall Consulting found no evidence of 'double counting'. Further, Nuttall Consulting recommended that the 'AMI leveraged projects' proposed by CitiPower and Powercor were not adequately justified and therefore should not be approved.

Issues and AER considerations

Table 8.49 below sets out the DNSPs' proposed expenditure in this cost category for the forthcoming regulatory control period.

Table 8.49 Victorian DNSPs' proposed 2011–15 capex—non-network—IT category ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
2011–15 proposed expenditure	44.9	104.7	58.8	143.0	98.5	**449.9**
Proportion of total gross direct capex (per cent)	4.7	6.8	10.4	11.8	10.8	**8.7**

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal , RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

The Victorian DNSPs have applied Guideline 3 to allocate assets to the various capex categories. The guideline defines the Non-network general assets cost category as:

> Expenditure associated with replacement, installation and maintenance of non-network assets such as, but not restricted to, vehicles, non-operational buildings and non-operational IT systems.[298]

The projects proposed by the Victorian DNSPs are summarised in table 8.50 below.

[298] Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 57.

Table 8.50 Victorian DNSPs' proposed capex projects —non-network—IT category

	Proposed projects
CitiPower	Distribution systems, customer service systems, corporate systems and IT infrastructure (network, hardware and systems)
Powercor	Distribution systems, customer service systems, corporate systems and IT infrastructure (network, hardware and systems)
Jemena	Disaster recovery data centre and SAP replacement, implementation of a Distribution Management System,
SP AusNet	Replacement , installation and maintenance of IT systems, implementation of IT solutions to enable the Asset Management Strategy (AMS)
United Energy	Replacement of 'end-of-life' IT systems, IT application and infrastructure projects to support United Energy's strategic objectives

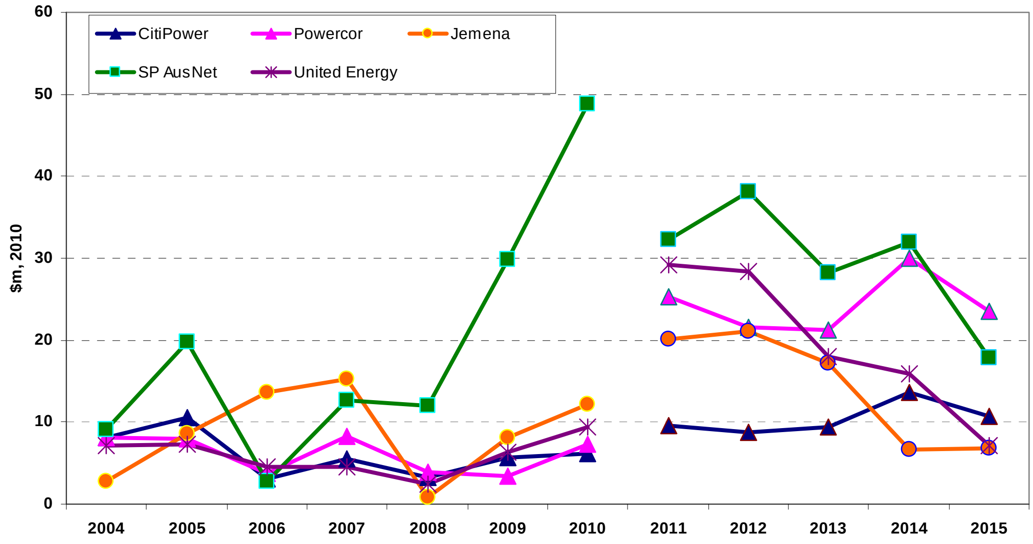
Source: CitiPower Regulatory Proposal, Powercor Regulatory Proposal, Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal, United Energy Regulatory Proposal.

Each DNSP has allocated project costs to this capex category on the basis of its assessment of the main project driver in the context of its understanding and interpretation of the Guideline 3 definition. Given that a project may have multiple drivers, DNSPs must exercise judgement to determine the main project driver and thereby allocate the project to a capex category. As a result, the AER notes that capex associated with Non-network–IT activities has been allocated by the DNSPs to one or more of the SCADA and Network Control, Non-network–IT, Reinforcement and Reliability and Quality Maintained capex categories.

The AER has not attempted to reallocate projects across categories to facilitate meaningful comparison of category expenditures across the DNSPs. Instead, the AER has assessed the Victorian DNSPs' proposals on a basis similar to that used by the ESCV in determining the benchmark allowances for the 2006–10 regulatory control period. As discussed at 8.6.2, AER analysis indicates that the DNSPs appear to spend significantly less than forecast and DNSP actual capex tends to follow a gradually increasing trend. Therefore, the historical underlying trend in capex has been used as the starting point for assessing the reasonableness of each DNSP's capex proposal.

Figure 8.15 below illustrates the expenditure trend in this cost category.

Figure 8.15 Victorian DNSPs' 2004–2015 capex—Non-network–IT ($m, 2010)



Note: Capex in this figure is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.
2004-2008 data is actual capex, 2009-2015 is forecast capex.

Source: CitiPower Regulatory Proposal, RIN template 2.1, Powercor Regulatory Proposal, RIN template 2.1, Jemena Regulatory Proposal, RIN template 2.1, SP AusNet, Regulatory Proposal, RIN template 2.1, United Energy Regulatory Proposal, RIN template 2.1.

The AER considers the variability of the capex amounts in this category relates to the periodic need to upgrade and/or replace assets. That is, although it may be desirable to upgrade IT hardware and software every 5 years, businesses may continue to utilise these assets as long as they are able to be operated and maintained without compromising customer service. As such, the historic trend cannot completely determine future requirements. However, the historic trend capex should include expenditures for changes which have eventuated in the current regulatory control period.

In identifying the underlying trend, the AER has considered data for 2004 to 2008 inclusive, from the current and previous regulatory control periods. The 2009 and 2010 data provided by the DNSPs is forecast data and therefore not considered to be part of the historical trend.

Table 8.51 below sets out the expenditure in this cost category for the current regulatory control period.

Table 8.51 Victorian DNSP 2006–10 capex—non-network—IT category ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
ESCV benchmark allowance	66.2	66.2	34.9	30.7	62.8
2006–10 expenditure	23.6	26.7	49.9	106.1	27.2
Variance (per cent)	–64.4	–59.7	43.0	245.6	–56.7

Note: Capex in this table is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 5.1, Powercor Regulatory Proposal, RIN templates 5.1, Jemena Regulatory Proposal, RIN templates 5.1, SP AusNet, Regulatory Proposal, RIN templates 5.1, United Energy Regulatory Proposal, RIN templates 5.1.

The reasons for the DNSPs' under/over-expenditure in relation to the benchmark allowance for the current regulatory control period are summarised in table 8.52 below.

Table 8.52 Victorian DNSP capex—non-network—IT category—explanation of variation between ESCV benchmark allowance and 2006–10 expenditure

	Explanation of variation
CitiPower	Redirection of IT resources to implementation of mandated AMI rollout project
Powercor	Redirection of IT resources to implementation of mandated AMI rollout project
Jemena	Redirection of IT resources to implementation of mandated AMI rollout project
SP AusNet	Change in capitalisation policy (IT infrastructure and Back Office systems capitalised instead - previously treated as opex)
United Energy	Redirection of IT resources to implementation of mandated AMI rollout project

Source: CitiPower Regulatory Proposal, Powercor Regulatory Proposal , Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal , United Energy Regulatory Proposal.

The AER considers it appropriate to allow adequate funding to implement and operate business IT systems supporting customer service and the operation and management of the network in accordance with good electricity industry practice. Given that similar issues and cost drivers were raised in support of the capex proposals for the current and previous regulatory control periods, the AER considers that the actual/out-turn expenditure represents the efficient capex amount.[299] That is, the Victorian DNSPs have over/underspent relative to the ESCV benchmark allowance on the basis of their own assessments of whether it is efficient to do so.

[299] Essential Services Commission, *Electricity Distribution Price Review 2006–10: Draft Decision,* June 2005, pp. 258–274.
Essential Services Commission, *Electricity Distribution Price Review 2006–10: Final Decision,* October 2006, pp. 299–320.

The AER considers that the business environment and the operational challenges and risks faced by the DNSPs have not changed between the current regulatory control period and the forthcoming regulatory control period. However, the DNSPs have indicated they face business operational risks from deferred/delayed IT investments. In particular, the DNSPs submitted reports from third-party IT consultants, vendors and service providers in support of an 'industry best practice' approach to IT investment. The AER sought Nuttall Consulting's assistance to clarify the nature of the DNSPs' IT environment and the likely risks faced by the DNSPs.

In assessing the Victorian DNSPs' proposed capex for the forthcoming regulatory control period, the AER sought to understand the reasons for the variation from historical capex trends. The AER requested additional supporting information from each DNSP, including cost drivers, changes in functions or legislative obligations and available information on projects included in the DNSPs' 'bottom-up' capex forecast cost build up. The DNSPs provided their indicative project lists to the AER. They explained they had relied upon technical engineering experience to derive the proposed project cost estimates because detailed business cases were typically prepared closer to the date of project implementation. Therefore, the AER considered whether the proposed indicative projects were linked to larger documented strategies/programs of work including an economic assessment of the need for the overall work program and the scale and timing of the proposed works.

The Victorian DNSPs provided detailed IT project plans for the forthcoming regulatory control period. They indicated that IT investments typically have a 5 to7 year life and require renewal thereafter. The AER notes that all of the DNSPs do not replace assets every 5 to 7 years and therefore, some of the proposed expenditure relates to renewal of IT infrastructure. The DNSPs explained that the timing of their replacement/upgrade of IT applications software was affected by the mandated Advanced Metering Infrastructure (AMI) roll-out. For example, CitiPower and Powercor deferred investment in a new Customer Information System while Jemena and United Energy will upgrade their SAP systems subject to functional integration with their new AMI systems.

The AER agrees with Nuttall Consulting's assessment that the DNSPs do not have 'agile' IT architecture supporting business operation and service delivery. The AER notes that the DNSPs' IT strategies do not discuss how their proposed IT investments would allow them to better respond in future to external events such as the mandated AMI rollout. The AER notes that each DNSP's IT activities in the current regulatory control period have been limited by operational capabilities and the amount of IT changes able to be tolerated by the DNSP. The AER accepts Nuttall Consulting's assessments that the absence of agile IT environments in the DNSPs will hinder their ability to complete the IT projects proposed for the forthcoming regulatory control period. In this regard, the AER notes that CitiPower and Powercor have already deferred upgrade/replacement of their Customer Information System from the current regulatory control period to 2014 in the forthcoming regulatory control period. Similarly, United Energy is proposing to consolidate its data centre in 2014–2015 in the forthcoming regulatory control period. The AER considers the DNSPs will likely defer projects or adopt alternative projects in the forthcoming regulatory control period. Therefore the AER has rejected the capex expenditure amounts proposed by each of the DNSPs in this capex category and has substituted amounts recommended by Nuttall Consulting as follows.

- CitiPower: the capex amount proposed by CitiPower for 2011–2013 has been spread evenly across 2011–2015
- Powercor: the capex amount proposed by Powercor for 2011–2013 has been spread evenly across 2011–2015
- Jemena: the capex amount proposed by Jemena for 2011–2013 has been spread evenly across 2011–2015
- SP AusNet: an average of $15 million ($2010, fully absorbed cost) per annum across 2011–2015
- United Energy: the capex amount proposed by United Energy for 2011–2013 has been spread evenly across 2011–2015.

Further, as part of the amounts proposed in this capex cost category, CitiPower and Powercor have proposed a project to 'leverage' functionality developed as part of the mandated rollout of Advanced Metering Infrastructure (AMI). Jemena and United Energy have each proposed to undertake a trial to assess the opportunities for utilising the data collected via AMI meters. Both DNSPs have recorded the costs of the trial as an 'operating expenditure' in the forthcoming regulatory control period, however, only United Energy has identified that the results of the trial may lead to development of demand management initiatives. In contrast, SP AusNet has identified a step change in its operating expenditure because of quality of supply investigations driven by increased customer complaints following increased awareness of the implementation of AMI.

The AER has considered whether projects proposing to 'leverage' AMI overlap in scope with those approved and included in the separate AER 2009 AMI determination. The AER notes that each of the Victorian DNSPs has stated that mandated investment in AMI is subject to a separate AER AMI determination.

In its 2009 AMI determination, the AER stated that its 2011–2015 Victorian electricity distribution determinations would not deal with the costs and revenues associated with AMI rollout.[300] That determination related to expenditure budgets and forecast revenues for 2009 to 2011. A second budget period applies from 1 January 2012 to 31 December 2015. The DNSPs are required to report actual expenditure incurred against the budgets approved by the AER. Further, where a DNSP is seeking to reflect actual expenditure in prices, the relevant expenditures must, among other things, be certified in an audit report.[301]

[300] Australian Energy Regulator, *Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications: Final determination*, October 2009, p. 1.
[301] Australian Energy Regulator, *Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications: Final determination*, October 2009, p. viii.

The AER sought Nuttall Consulting's assistance in investigating overlap of project scope between the AER AMI determination and the capex proposed in the Non-network - IT capex cost category for the forthcoming regulatory control period.

Nuttall Consulting reviewed the information received by the AER at the time of its 2009 AMI determination. It then focussed its investigation on the compute platform, storage platform, IT network/connectivity and DNSP IT systems and sought to identify potential usage overlap between AMI and non-AMI activities. Nuttall Consulting found no evidence of 'double counting'. The AER has accepted the findings of Nuttall Consulting's investigation.

In the case of the 'AMI leveraged projects' proposed by CitiPower and Powercor, the AER notes that the DNSPs did not submit an internal assessment in support of their proposed joint project to leverage data available from the mandated AMI roll-out. Instead, they relied on a PriceWaterhouseCoopers (PWC) report on the application of a Regulatory Investment Test style cost-benefit analysis to the proposed project. The PWC report indicated that project benefits largely comprised network reliability improvements and enhanced load shedding capabilities. The AER considers the S-factor scheme provides financial incentives to the DNSPs for implementing projects to achieve reliability benefits. Further, the AER considers that the implementation of enhanced load shedding capabilities may defer some network reinforcement projects. As such, the DNSPs' reinforcement capex amounts should allow for implementation of enhanced load shedding capabilities. Therefore the AER has rejected the capex expenditure amounts proposed by CitiPower and Powercor for this project.

In summary, the AER considers that the project information provided by CitiPower, Powercor, Jemena, SP AusNet and United Energy:

- has not adequately demonstrated how engineering judgements have been translated into a step change in expenditure and, in particular, did not establish a clear link between exercise of judgement and economic efficiency
- has not demonstrated an underlying need for a step increase in investment supported by an economic justification (cost benefit analysis including options analysis)
- has not demonstrated why they cannot manage existing programs and associated risks within the current level of expenditure and existing practices as achieved in the current period - given that they have successfully managed risks to within acceptable parameters in the current period
- did not attempt to quantify the benefits and outcomes for customers achieved by the forecast level of investment.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the information submitted in support of the Non-network–IT capex proposal, the AER is not satisfied that the projects proposed by CitiPower, Powercor, Jemena, SP AusNet and United Energy reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods
- the respective prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure.

and, where relevant, has made the minimum necessary change to the DNSPs' proposals.

Table 8.53 below sets out the AER's conclusion on the Victorian DNSPs' proposed expenditure in the Non-network–IT capex cost category for the forthcoming regulatory control period.

The AER notes that capex may appear lumpy within a capex category, however, the total capex allowance is not tied to a fixed, project-specific work program. In this regard, the AER notes that although the DNSPs have indicated they have prepared their capex forecasts on a detailed project-by-project basis, and the AER has for the most part assessed expenditure in this way, the AER's conclusions relate to a total forecast capex allowance for this capex cost category.

Table 8.53 AER conclusion on Victorian DNSP 2011–15 capex—non-network—IT category ($m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	5.0	4.9	4.9	4.7	4.7	24.2
Powercor	12.2	12.1	12.0	11.4	11.4	59.1
Jemena	9.8	9.6	9.5	9.3	9.1	47.3
SP AusNet	14.8	14.6	14.4	14.2	14.0	72.0
United Energy	19.7	19.7	19.7	19.7	19.7	98.5
Total	**61.5**	**61.0**	**60.5**	**59.3**	**59.0**	**301.1**

Note: Totals may not add due to rounding.

8.12.2 Non-network–Other capex

Introduction

This section focuses on capital expenditure relating to Non-network–Other.

The Victorian DNSPs have applied Guideline 3 to allocate assets to the various capex categories. The guideline defines the Non-network general assets cost category as:

> Expenditure associated with the replacement, installation and maintenance of non-network assets such as, but not restricted to, vehicles, non-operational buildings and non-operational IT systems.[302]

Approach

In assessing and determining whether each of the Victorian DNSPs' proposed Non-network–Other capex forecast and the AER's estimate of the required Non-network–Other capex reasonably reflects the capex criteria, the AER has had regard to the capex factors, as relevant. Specifically, the AER's analysis of Non-network–Other capex takes into account:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period. Appendix I to this draft decision sets out the AER's analysis which benchmarks the Victorian DNSPs against interstate DNSPs
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods. The AER has compared the actual Non-network–Other capex incurred in the current and previous regulatory control periods with the corresponding ESCV allowances. The observed trends in actual capex have been considered in the AER's estimate of the required capex for the forthcoming regulatory control period
- the respective prices of operating and capital inputs. Appendix K to this draft decision sets out the AER's analysis of the costs escalators with respect to the Victorian DNSPs expenditure proposals
- the substitution possibilities between operating and capital expenditure. The DNSPs' allocation of costs to Non-network–Other capex having regard to their respective capitalisation policies and Guideline 3) has been considered in the AER's estimate of the required capex for the forthcoming regulatory control period.

Further, the AER has examined whether the DNSPs' proposals are in accordance with good industry practice, consistent with achieving the lowest sustainable cost of delivering services, including whether:

- there is a justifiable need for the proposed capex
- the DNSP objectively and competently analysed the investment to a standard that is consistent with good industry practice
- the proposed projects align with the DNSP's strategic capex plans and policies

In considering the DNSPs' proposals, the AER also considered:

[302] Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 57.

- materiality—the cost associated with the Non-network–Other capex as a proportion of the total capex and the cost associated with the DNSPs’ proposed projects as a proportion of the total Non-network–Other capex
- timing of the proposed expenditure—the drivers of any changes in timing and the processes or systems to ensure prudent decision-making. Further, any economic analysis which clearly demonstrates the need to undertake the proposed projects in the forthcoming regulatory control period
- variations in project costs and scope from original estimates—this provides insight into the governance and business practices for undertaking capital projects and how cost-estimating processes incorporate feedback from specific experience.

Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed capex is set out at table 8.54 below.

Table 8.54 Victorian DNSPs’ proposed capex—non-network—other category ($m, 2010)

	2006–10	2011	2012	2013	2014	2015	Total	Increase (per cent)
CitiPower	11.6	3.2	3.6	3.2	3.2	3.2	16.4	40
Powercor	86.9	16.6	17.6	16.7	16.8	16.8	84.5	–3
Jemena	32.0	17.2	8.1	6.8	4.0	5.5	41.7	30
SP AusNet	32.0	9.6	6.5	6.2	6.3	6.2	34.7	9
United Energy	21.4	2.1	4.7	1.9	2.7	1.8	13.1	–39
Total	**183.9**	**48.7**	**40.6**	**34.6**	**33.0**	**33.4**	**190.4**	**4**

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

The DNSPs’ forecasts represent capex amounts relating to property, plant, equipment and motor vehicles.

Summary of submissions

The AER received no submissions on the Non-network–Other capex proposed by the Victorian DNSPs.

Consultant review

Nuttall Consulting's review focussed on Jemena's proposed expenditure in the Non-network–Other capex category because of the significant proposed increase above historical trends.

Nuttall Consulting considered that Jemena's proposed capex for the merger and relocation of the Broadmeadows and Sunshine depots was not adequately justified and therefore should not be approved.[303] Further, Nuttall Consulting recommended that Jemena's land purchases relating to proposed zone substation developments be considered as part of the assessment of the Reinforcement capex category.

Issues and AER considerations

Table 8.55 below sets out the DNSPs' proposed expenditure in this cost category for the forthcoming regulatory control period.

Table 8.55 Victorian DNSP 2011–15 capex—non-network—other category ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Total
2011–15 proposed expenditure	16.4	84.5	41.7	34.7	13.1	190.4
Proportion of total gross direct capex (per cent)	1.7	5.5	7.4	2.9	1.4	3.7

Note: Totals may not add due to rounding.
Capex in this table is at a direct cost level and excludes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN templates 2.1 and 3.1, Powercor Regulatory Proposal, RIN templates 2.1 and 3.1, Jemena Regulatory Proposal, RIN templates 2.1 and 3.1, SP AusNet, Regulatory Proposal, RIN templates 2.1 and 3.1, United Energy Regulatory Proposal, RIN templates 2.1 and 3.1.

The Victorian DNSPs have applied Guideline 3 to allocate assets to the various capex categories. The guideline defines the Non-network general assets cost category as:

> Expenditure associated with the replacement, installation and maintenance of non-network assets such as, but not restricted to, vehicles, non-operational buildings and non-operational IT systems.[304]

The projects proposed by the Victorian DNSPs are summarised in table 8.56 below.

[303] Nuttall Consulting, *Victorian Electricity Distribution Revenue Review*, May 2010, pp. 170–171.
[304] Essential Services Commission, *Electricity Industry Guideline No.3 Regulatory Information Requirements Issue No.6*, December 2006, p. 57.

Table 8.56 Victorian DNSPs' proposed capex projects—non-network—other category

	Proposed projects
CitiPower	'Business as usual expenditure' - General equipment, motor vehicles, property (office accommodation and depots)
Powercor	General equipment, motor vehicles (in particular, inspection and upgrade of cranes), property (office accommodation and depots)
Jemena	Motor vehicle fleet replacement, office/depot relocation, land purchase for proposed zone substation developments
SP AusNet	Purchase of minor tools and equipment
United Energy	Motor vehicle fleet replacement, property (office accommodation)

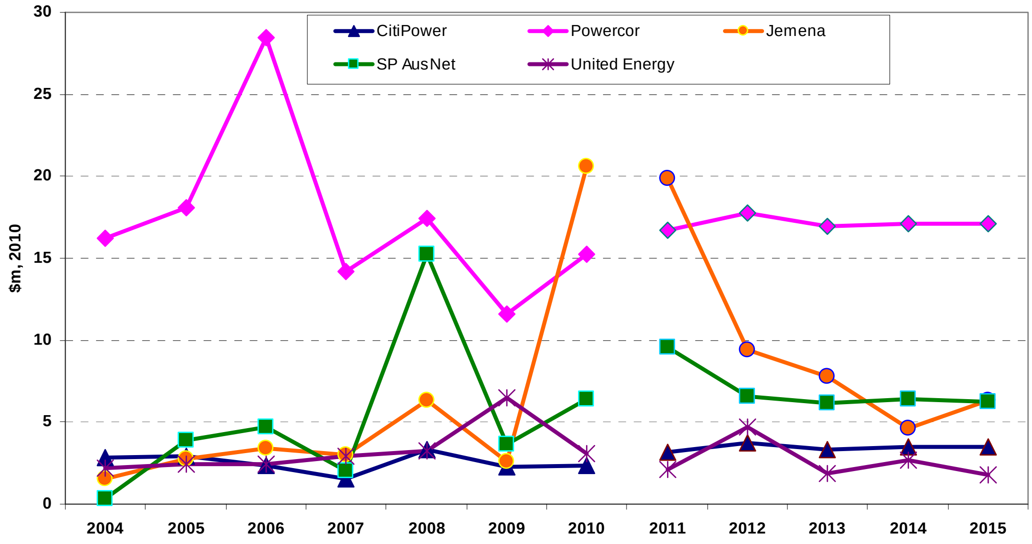
Source: CitiPower Regulatory Proposal, Powercor Regulatory Proposal, Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal, United Energy Regulatory Proposal.

Each DNSP has allocated project costs to this capex category on the basis of its assessment of the main project driver in the context of its understanding and interpretation of the Guideline 3 definition. Given that a project may have multiple drivers, DNSPs must exercise judgement to determine the main project driver and thereby allocate the project to a capex category. As a result, the AER notes that Jemena has included land purchases associated with proposed network zone substation developments in this capex category while the other DNSPs have included such purchases in the Reinforcement capex category. Further, Powercor has included capex to replace mobile cranes in order to achieve compliance with Australian Standards AS1418 and AS2550.5 (Cranes Hoist & Winches—Safe Use—Part 5 Mobile Cranes).

The AER has sought to assess the Victorian DNSPs' proposals on a basis similar to that used by the ESCV in determining the benchmark allowances for the 2006–2010 regulatory control period. As discussed at 8.6.2, AER analysis indicates that the DNSPs appear to spend significantly less than forecast, and previously allowed, and DNSP actual capex tends to follow a gradually increasing trend. Therefore, the historical underlying trend in capex has been used as the starting point for assessing the reasonableness of each DNSP's capex proposal.

Figure 8.16 below illustrates the expenditure trend in this cost category.

Figure 8.16 Victorian DNSPs' 2004–2015 capex—Non-network–Other ($m, 2010)



Note: Capex in this figure is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.
2004-2008 data is actual capex, 2009-2015 is forecast capex.

Source: CitiPower Regulatory Proposal, RIN template 2.1, Powercor Regulatory Proposal, RIN template 2.1, Jemena Regulatory Proposal, RIN template 2.1, SP AusNet, Regulatory Proposal, RIN template 2.1, United Energy Regulatory Proposal, RIN template 2.1.

The AER notes the variability of the capex amounts in this category relates to changes in purchasing and/or capitalisation policies and the periodic need to upgrade and/or replace assets. As such, the historic trend cannot completely determine future requirements. However, the historic trend capex should include expenditures for changes which have eventuated in the current regulatory control period.

In identifying the underlying trend, the AER has considered data for 2004–08 inclusive, from the current and previous regulatory control periods. The 2009 and 2010 data provided by the DNSPs is forecast data and therefore not considered to be part of the historical trend.

Table 8.57 below sets out the expenditure in this cost category for the current regulatory control period.

Table 8.57 Victorian DNSP 2006–10 capex—non-network—other category ($m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
ESCV benchmark allowance	62.4	62.4	15.2	1.7	14.8
2006–10 expenditure	11.8	87.0	35.9	32.0	18.1
Variance (per cent)	–81.1	39.4	136.2	1 782.4	22.3

Note: Capex in this table is not at a direct cost level and includes DNSPs' proposed margins, overheads and real cost increases.

Source: CitiPower Regulatory Proposal, RIN template 5.1, Powercor Regulatory Proposal, RIN template 5.1, Jemena Regulatory Proposal, RIN template 5.1, SP AusNet, Regulatory Proposal, RIN template 5.1 United Energy Regulatory Proposal, RIN template 5.1.

The reasons for the DNSPs' under/over-expenditure in relation to the benchmark allowance for the current regulatory control period are summarised in table 8.58 below.

Table 8.58 Victorian DNSP capex—non-network—other category—explanation of variation between ESCV benchmark allowance and 2006–10 expenditure

	Explanation of variation
CitiPower	No explanation provided by DNSP
Powercor	No explanation provided by DNSP
Jemena	No explanation provided by DNSP
SP AusNet	Unwinding of contracting arrangements with Tenix Alliance in the current regulatory control period
United Energy	No explanation provided by DNSP

Source: CitiPower Regulatory Proposal, Powercor Regulatory Proposal, Jemena Regulatory Proposal, SP AusNet, Regulatory Proposal, United Energy Regulatory Proposal.

The AER considers it appropriate to allow adequate funding to non-operational activities supporting management and operation of the network in accordance with good electricity industry practice. Given that similar issues and cost drivers were raised in support of the capex proposals for the current and previous regulatory control periods, the AER considers that the actual/out-turn expenditure represents the efficient capex amount.[305] That is, the Victorian DNSPs have over/underspent relative to the ESCV benchmark allowance on the basis of their own assessments of whether it is efficient to do so.

[305] Essential Services Commission, *Electricity Distribution Price Review 2006–10: Draft Decision,* June 2005, pp. 258–274.
Essential Services Commission, *Electricity Distribution Price Review 2006–10: Final Decision,* October 2006, pp. 299–320.

In assessing the Victorian DNSPs' proposed capex for the forthcoming regulatory control period, the AER sought to understand the reasons for the variation from historical capex trends. The AER requested additional supporting information from each DNSP, including cost drivers, changes in functions or legislative obligations and available information on projects included in the DNSPs' 'bottom-up' capex forecast cost build up. The DNSPs provided their indicative project lists to the AER. They explained they had relied upon technical engineering experience to derive the proposed project cost estimates because detailed business cases were typically prepared closer to the date of project implementation. Further, the projects in this capex category typically related to volume purchase of relatively low capital cost items such as office furniture, motor vehicles and general equipment. Therefore, the AER considered whether the proposed indicative projects were linked to larger documented purchasing strategies/programs including an economic assessment of the need for the scale and timing of the proposed purchases.

The AER notes that Jemena was the only DNSP to propose inclusion of land associated with zone substation developments in this category. Jemena's proposal includes land for the proposed Alphington, Broadmeadows South, Craigieburn, Tullamarine and Bulla zone substations in the Non-network–Other capex category. Although Jemena stated it has historically included land purchase in this capex category, the AER considers this is not consistent with the Guideline 3 definition above because these assets relate to network operations. Therefore, the AER considers that the relevant amounts should be transferred from the Non-network–Other capex category to the Reinforcement capex category. As a result, these projects (and associated expenditures) have been reallocated and considered as part of the assessment of Jemena's proposed Reinforcement capex.

Jemena had also proposed capex for a project to merge and relocate its Broadmeadows and Sunshine depots. The AER notes Nuttall Consulting's view that the project is not adequately justified and its recommendation that the associated proposed capex not be allowed. The AER has reviewed the draft business case submitted in support of the proposed project and considers that capex will be incurred in the forthcoming regulatory control period for relocation of the Sunshine depot. However, the draft business case does not separately identify the costs associated with relocating the Sunshine depot. For this reason, the AER has rejected the total amount proposed for the project and has substituted zero capex in its place.

In the case of Powercor's proposed replacement of mobile cranes, the AER has not reallocated the project to the Environmental, Safety and Legal capex category. The AER notes Powercor's view that a cost-benefit analysis is not required because it considers the project must be undertaken to achieve full compliance with the relevant Australian Standard. In response, the AER considers such assessments are appropriate even in circumstances where action is mandated by legislation/regulation or by a regulatory body and notes that when there is a change to a legislative obligation, there is typically a transition period for a business to achieve compliance. In this case, the relevant Australian Standard AS2550.5 was introduced in 2004 and Powercor has stated that its estimated project expenditure is 'based on a catch up cost to comply with safety requirements for cranes to accord with the Australian Standards'. The AER notes that a risk management approach to compliance allows businesses to assess their obligations and bear compliance risk where they are willing to do so.

Powercor has indicated that a number of the mobile cranes will be replaced in the forthcoming regulatory control period, however, it has not provided information regarding the total number of replacements required and the timeframe for completion of replacements. For this reason, the AER has rejected the total amount proposed by Powercor for the project and has substituted 50 per cent of the proposed project amount in its place as the AER's best estimate of Powercor's likely expenditure on mobile cranes in the forthcoming regulatory control period.

In the case of SP AusNet, the AER notes that it has significantly increased its capex in this cost category in the current regulatory control period. SP AusNet explained that it unwound its contracting arrangements with Tenix Alliance in the current regulatory control period and the capex spike in 2008 relates to its decision to purchase rather than lease motor vehicles. SP AusNet has since reverted to leasing its motor vehicles. It advised that its Non-network–Other capex in 2008 would have been $4.2 million ($2010, fully absorbed cost), excluding the motor vehicle purchases. The AER notes SP AusNet's observation that Non-network–Other capex 'is always the first category cut when financing constraints [are] experienced'. Therefore, the AER has rejected the proposed capex amounts and has substituted amounts based on a continuation of the historical expenditure trend in this capex category. Given SP AusNet proposes to continue leasing its vehicles in the forthcoming regulatory control period, the AER has substituted $4.2 million ($2010, fully absorbed cost) in place of $15.25 million ($2010, fully absorbed cost) actual expenditure reported in this cost category in 2008 to determine the historical expenditure trend.

In contrast, the AER considers the CitiPower and United Energy proposed capex in this cost category is consistent with a continuation of the historical expenditure trend in this capex category. The AER accepts their proposed capex for this cost category.

In summary, the AER considers that the project information provided by Powercor, Jemena and SP AusNet:

- has not adequately demonstrated how engineering judgements have been translated into a step change in expenditure and, in particular, did not establish a clear link between the exercise of judgement and economic efficiency
- has not demonstrated an underlying need for a step increase in investment supported by an economic justification (cost benefit analysis including options analysis)
- has not demonstrated why they cannot manage existing programs and associated risks within the current level of expenditure and existing practices as achieved in the current period—given that they have successfully managed risks to within acceptable parameters in the current regulatory control period.

AER conclusion

For the reasons discussed and as a result of the AER's analysis of the information submitted in support of the Non-network–Other capex proposal, the AER is:

- not satisfied that the projects proposed by Powercor, Jemena and SP AusNet reasonably reflects the capex criteria, including the capex objectives

- satisfied that the projects proposed by CitiPower and United Energy reasonably reflects the capex criteria, including the capex objectives.

In coming to this view, the AER has had regard to the capex factors:

- the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period
- the actual and expected capital expenditure of the DNSP during any preceding regulatory control periods
- the respective prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure.

and, where relevant, has made the minimum necessary change to the DNSPs' proposals.

Table 8.59 below sets out the AER's conclusion on the Victorian DNSPs' proposed expenditure in the Non-network–Other capex cost category for the forthcoming regulatory control period.

The AER notes that capex may appear lumpy within a capex category, however, the total capex allowance is not tied to a fixed, project-specific work program. In this regard, the AER notes that although the DNSPs have indicated they have prepared their capex forecasts on a detailed project-by-project basis, and the AER has for the most part assessed expenditure in this way, the AER's conclusions relate to a total forecast capex allowance for this capex cost category.

Table 8.59 AER conclusion on Victorian DNSP 2011–15 capex—non-network—other category ($m, 2010)

	2011	2012	2013	2014	2015	Total
CitiPower	3.2	3.6	3.2	3.2	3.2	16.4
Powercor	8.0	8.0	8.0	8.0	8.0	40.0
Jemena	3.3	2.6	3.4	3.5	4.0	16.8
SP AusNet	3.6	3.6	3.6	3.6	3.6	18.2
United Energy	2.1	4.7	1.9	2.7	1.8	13.2
Total	**20.2**	**22.5**	**20.1**	**21.0**	**20.6**	**104.5**

Note: Totals may not add due to rounding.

8.13 AER conclusion

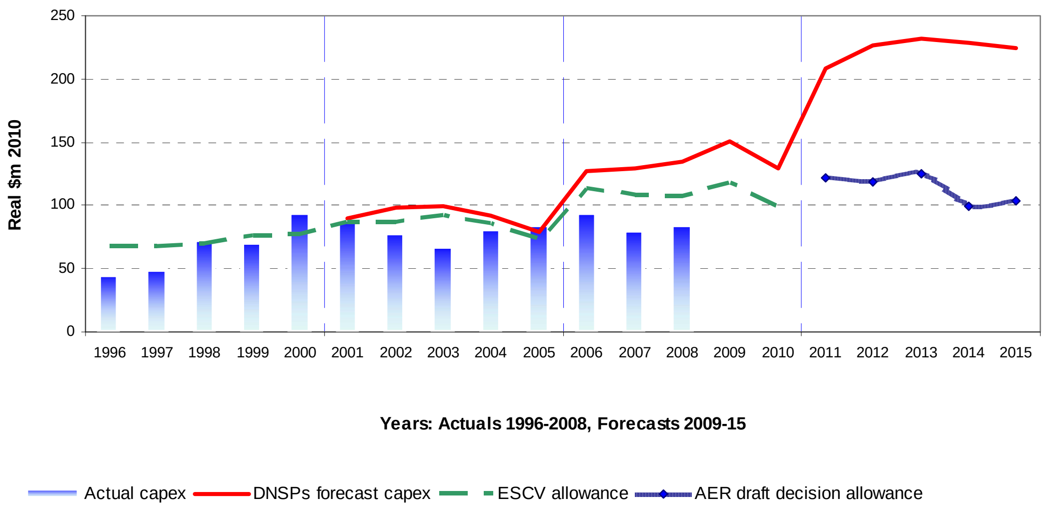
The AER has reviewed CitiPower's forecast capex allowance, and for the reasons set out in this chapter, the AER is not satisfied that the proposed forecast capex allowance for CitiPower reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER.

As the AER is not satisfied that CitiPower's 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 CitiPower. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of capital expenditure for each DNSP for the forthcoming regulatory control period, which it is satisfied reasonably reflects the capex criteria, taking account of the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast capital expenditure for CitiPower is set out in table 8.60 and figure 8.17. The AER's draft decision has been broken down by gross direct capex, direct overheads, indirect overheads, real cost increases, margins and contributions.

Table 8.60 AER conclusion on CitiPower's capital expenditure ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Gross direct capex	112.9	108.7	112.9	90.0	93.2	**517.7**
Direct overheads	9.6	9.2	9.6	7.5	7.8	**43.6**
Indirect overheads	14.4	14.6	14.8	15.1	15.3	**74.2**
Cost increases	6.2	7.7	9.2	8.4	8.8	**40.3**
Margins	0.0	0.0	0.0	0.0	0.0	**0.0**
Less contributions	–21.8	–21.8	–21.7	–21.6	–21.7	**–108.5**
Total net capex	**121.3**	**118.4**	**124.9**	**99.4**	**103.3**	**567.4**

Figure 8.17 CitiPower's draft decision capital expenditure ($'m, 2010)



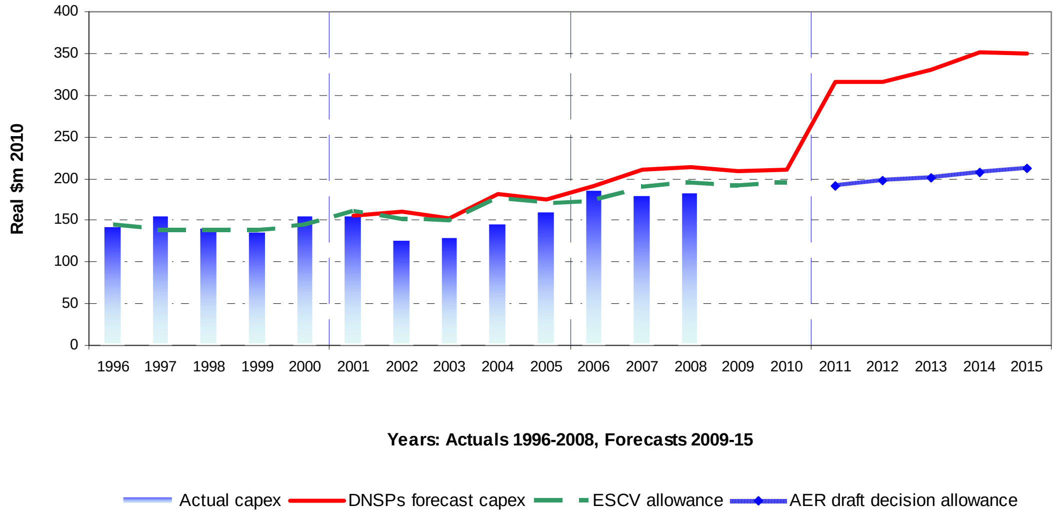
The AER has reviewed Powercor's forecast capex allowance, and for the reasons set out in this chapter, the AER is not satisfied that the proposed forecast capex allowance for Powercor reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER.

As the AER is not satisfied that Powercor's 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 Powercor. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of capital expenditure for each DNSP for the next regulatory control period, which it is satisfied reasonably reflects the capex criteria, taking account of the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast capital expenditure for Powercor is set out in table 8.61 and figure 8.18. The AER's draft decision has been broken down by gross direct capex, direct overheads, indirect overheads, real cost increases, margins and contributions.

Table 8.61 AER conclusion on Powercor's capital expenditure ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Gross direct capex	209.1	212.5	215.0	218.5	222.5	**1077.5**
Direct overheads	5.1	5.2	5.3	5.4	5.5	**26.6**
Indirect overheads	22.6	23.0	23.4	23.9	24.2	**117.2**
Cost increases	11.2	14.0	15.9	18.5	19.3	**78.9**
Margins	0.0	0.0	0.0	0.0	0.0	**0.0**
Less contributions	–56.7	–57.6	–58.0	–58.9	–59.8	**–291.0**
Total net capex	**191.4**	**197.1**	**201.6**	**207.4**	**211.8**	**1009.2**

Figure 8.18 Powercor's draft decision capital expenditure ($'m, 2010)



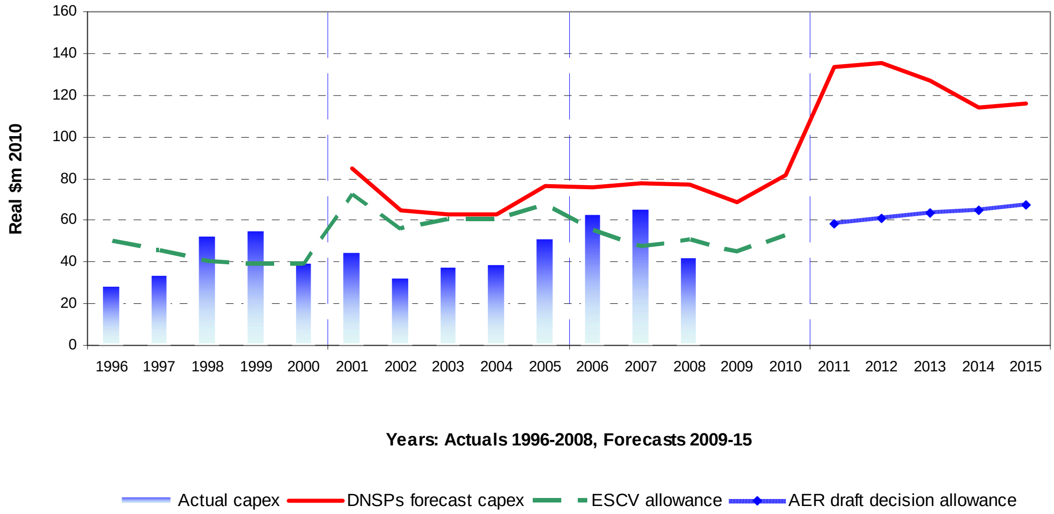
The AER has reviewed Jemena's forecast capex allowance, and for the reasons set out in this chapter, the AER is not satisfied that the proposed forecast capex allowance for Jemena reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER.

As the AER is not satisfied that Jemena's 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 Jemena. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of capital expenditure for each DNSP for the forthcoming regulatory control period, which it is satisfied reasonably reflects the capex criteria, taking account of the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast capital expenditure for Jemena is set out in table 8.62 and figure 8.19. The AER's draft decision has been broken down by gross direct capex, direct overheads, indirect overheads, real cost increases, margins and contributions.

Table 8.62 AER conclusion on Jemena's capital expenditure ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Gross direct capex	64.2	66.2	68.6	70.5	74.1	**343.5**
Direct overheads	1.3	1.3	1.3	1.4	1.4	**6.7**
Indirect overheads	2.8	2.8	2.9	2.9	3.0	**14.4**
Cost increases	0.8	1.2	1.4	1.7	1.7	**6.8**
Margins	0.0	0.0	0.0	0.0	0.0	**0.0**
Less contributions	–10.5	–10.7	–11.0	–11.8	–12.8	**–56.9**
Total net capex	**58.5**	**60.9**	**63.2**	**64.7**	**67.4**	**314.6**

Figure 8.19 Jemena's draft decision capital expenditure ($'m, 2010)



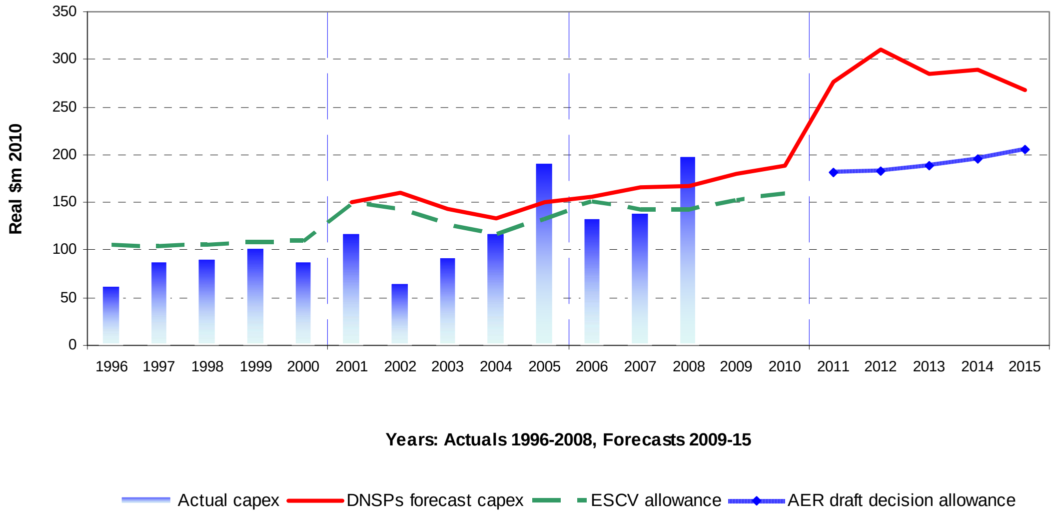
The AER has reviewed SP AusNet's forecast capex allowance, and for the reasons set out in this chapter, the AER is not satisfied that the proposed forecast capex allowance for SP AusNet reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER.

As the AER is not satisfied that SP AusNet's 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 SP AusNet. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of capital expenditure for each DNSP for the forthcoming regulatory control period, which it is satisfied reasonably reflects the capex criteria, taking account of the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast capital expenditure for SP AusNet is set out in table 8.63 and figure 8.20. The AER's draft decision has been broken down by gross direct capex, direct overheads, indirect overheads, real cost increases, margins and contributions.

Table 8.63 AER conclusion on SP AusNet's capital expenditure ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Gross direct capex	169.8	168.1	169.6	173.2	183.2	**863.9**
Direct overheads	11.4	11.4	11.6	11.9	12.7	**59.1**
Indirect overheads	14.5	14.5	15.1	15.7	16.1	**75.9**
Cost increases	9.6	11.6	13.2	15.5	16.8	**66.7**
Margins	0.0	0.0	0.0	0.0	0.0	**0.0**
Less contributions	–24.0	–22.4	–21.0	–21.4	–23.4	**–112.2**
Total net capex	**181.3**	**183.2**	**188.6**	**194.9**	**205.4**	**953.3**

Figure 8.20 SP AusNet's draft decision capital expenditure ($'m, 2010)



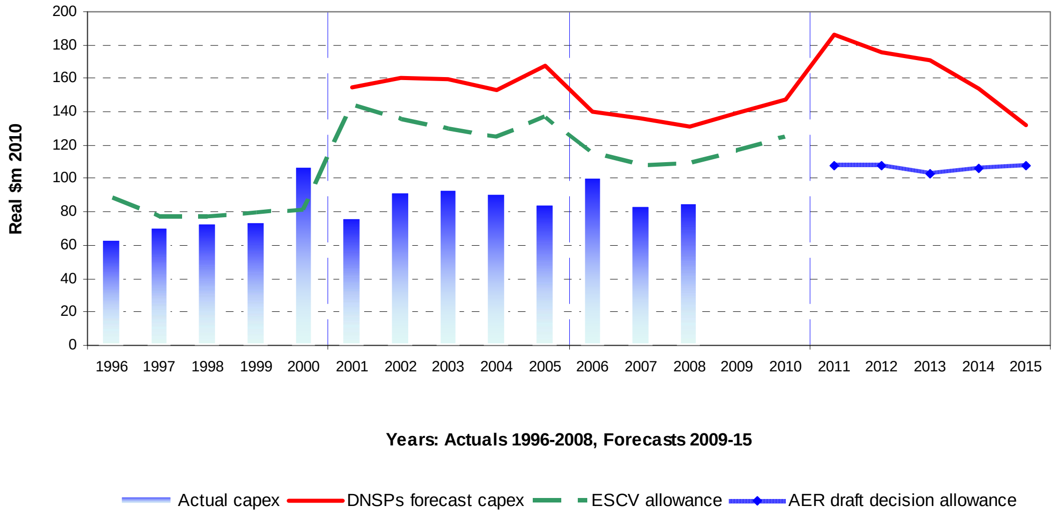
The AER has reviewed United Energy's forecast capex allowance, and for the reasons set out in this chapter, the AER is not satisfied that the proposed forecast capex allowance for United Energy reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER.

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 United Energy. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of capital expenditure for each DNSP for the forthcoming regulatory control period, which it is satisfied reasonably reflects the capex criteria, taking account of the capex factors. Allowing for the adjustments listed above, the AER's estimate of forecast capital expenditure for United Energy is set out in table 8.64 and figure 8.21. The AER's draft decision has been broken down by gross direct capex, direct overheads, indirect overheads, real cost increases, margins and contributions.

Table 8.64 AER conclusion on United Energy's capital expenditure ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Gross direct capex	128.8	128.0	124.1	127.8	128.5	**637.2**
Direct overheads	0.0	0.0	0.0	0.0	0.0	**0.0**
Indirect overheads	0.0	0.0	0.0	0.0	0.0	**0.0**
Cost increases	1.8	2.1	2.8	3.9	4.7	**15.3**
Margins	0.0	0.0	0.0	0.0	0.0	**0.0**
Less contributions	–22.7	–22.8	–24.4	–25.5	–25.5	**–120.9**
Total net capex	**107.9**	**107.3**	**102.6**	**106.2**	**107.7**	**531.5**

Figure 8.21 United Energy's draft decision capital expenditure ($'m, 2010)



The capital expenditure discussion and figures above are exclusive of equity raising costs. The benchmark equity raising costs for CitiPower, Jemena and Powercor shown in table 8.65 which will be added to the RAB at the start of the forthcoming regulatory control period. The AER's analysis considers that Jemena does not require benchmarking of equity raising costs in the forthcoming regulatory control period. SP AusNet and United Energy have not requested equity raising costs in the forthcoming regulatory control period. A detailed analysis and discussion of benchmark equity raising costs is considered in appendix I.

Table 8.65 AER conclusion on equity raising costs ($'m, 2010)

Cash flow analysis	CitiPower	Jemena	Powercor	Notes
Total equity raising cost	2.3	-	1.4	To be added to the RAB at the start of the forthcoming regulatory control period

In relation to the current regulatory control period outcomes, the AER considered whether any adjustment was required for asset disposal for the current regulatory control period. The AER is satisfied that each business has properly accounted for asset disposal and retirements and no adjustments to the current period actual expenditure to be rolled in to the regulatory asset base are required.

9 Opening asset base

9.1 Introduction

This chapter sets out the method used by the AER to determine the closing regulatory asset base (RAB) for the Victorian distribution network service providers (DNSPs) for the current regulatory control period. The closing RAB becomes the opening RAB for the forthcoming regulatory control period and is used to calculate the return on and return of capital building block components.

9.2 Regulatory requirements

Clause 6.5.1 of the National Electricity Rules (NER) outlines the approach to be used to determine the opening RAB for a distribution determination. 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.

Clause S6.2.1(c)(1) provides that Victorian DNSPs' RAB for the first year of the forthcoming regulatory control period must be determined by rolling forward the RAB value ($ real 2004, as at 1 January 2006) for each DNSP as follows:

- CitiPower—990.9 million
- Powercor—1 626.5 million
- Jemena Electricity Networks (Victoria) (Jemena)—578.4 million
- SP AusNet—1 307.2 million
- United Energy Distribution (United Energy)—1 220.3 million.

Clause S6.2.1(c)(2) provides that these values are to be adjusted to allow for the difference between estimated capex and actual capex in the 2001–05 regulatory control period. This adjustment must also remove any benefit or penalty associated with any such difference.

Clause S6.2.1(c)(3) states that

> …the AER must take into account the derivation of the values in the above table [schedule] from past regulatory decisions and the consequent fact that they relate only to the RAB identified in those decisions from past regulatory decisions

Clause S6.2.1(e) contains detailed provisions on how these values are further adjusted to roll forward and calculate the RAB at the beginning of the first year of the forthcoming regulatory control period. Clause 6.5.1(e)(3) requires that the roll forward of the RAB from the immediately preceding regulatory control period to the beginning of the first regulatory year of the forthcoming regulatory control period include an adjustment for actual inflation, consistent with the method used for the indexation of the control mechanism (or control mechanisms) for standard control services during the preceding regulatory control period.

Clause S6.1.3(10) requires Victorian DNSPs to provide a completed RFM with their regulatory proposals.

Clause 6.3.2(a)(2) requires that a building block determination specify, among other things, appropriate methods for the indexation of the RAB.

9.3 Summary of Victorian DNSP regulatory proposals

Victorian DNSPs' proposed roll forward calculations for the 2006–10 regulatory control period are summarised at table 9.1.

Among the five Victorian DNSPs, only United Energy submitted a completed version of the AER's published RFM with its own adjustments. The other four DNSPs submitted their own roll forward models. In preparing its regulatory proposal, Jemena sought confirmation from the AER that its published RFM was unlikely to be fit for purpose due to Victorian specific modelling issues, requiring the submission of an alternative model. This was agreed by the AER and communicated to the other DNSPs.[1]

1 Email AER staff to Jemena staff, *roll-forward model compliance issues*, 13 November 2009.

Table 9.1 Victorian DNSP proposed RAB roll forward for the current regulatory control period ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 176.8	1 194.1	1 197.4	1 206.5	1 238.4
Net capex	93.6	79.0	84.7	102.4	124.7
Depreciation	–76.3	–75.7	–75.6	–70.5	–72.0
Compound return on 2005 capex difference					–
Closing RAB	1 194.1	1 197.4	1 206.5	1 238.4	1 291.0
Powercor					
Opening RAB	1 915.0	1 977.1	2 035.4	2 094.5	2 143.6
Net capex	182.3	179.1	181.5	174.0	199.1
Depreciation	–120.1	–120.9	–122.4	–124.9	–126.1
Compound return on 2005 capex difference					–
Closing RAB	1 977.1	2 035.4	2 094.5	2 143.6	2 216.6
Jemena					
Opening RAB	661.5	682.2	703.6	699.8	710.2
Net capex	64.0	66.3	41.9	57.3	92.8
Depreciation	–43.2	–44.9	–45.7	–46.9	–47.4
Compound return on 2005 capex difference					–
Closing RAB	682.2	703.6	699.8	710.2	755.6
SP AusNet					
Opening RAB	1 591.1	1 639.4	1 685.1	1 785.1	1 944.6
Net capex	132.8	138.7	199.1	263.8	256.1
Depreciation	–84.4	–93.0	–99.0	–104.3	–109.8
Compound return on 2005 capex difference					16.4
Closing RAB	1 639.4	1 685.1	1 785.1	1 944.6	2 107.3
United Energy					
Opening RAB	1 388.6	1 381.5	1 359.0	1 334.3	1 365.2
Net capex	97.7	83.9	85.4	124.4	124.9
Depreciation	–104.8	–106.4	–110.1	–93.4	–82.6
Compound return on 2005 capex difference					–
Closing RAB	1 381.5	1 359.0	1 334.3	1 365.2	1 407.5

Note: CitiPower, Powercor and United Energy submitted their roll forward models in real 2010 dollars. SP AusNet submitted its roll forward model both in real 2010 dollar and nominal terms. Jemena submitted its roll forward model in real 2004 dollars, which has been converted to real 2010 dollars using its inflation adjustment, for purpose of comparison with the other DNSPs in the table.

Source: Victorian DNSPs' Regulatory proposals, Attachment, RAB Roll Forward Model, November 2009.

9.4 Summary of submissions

The Consumer Action Law Centre (CALC) submitted that the AER should assess any over-spend of capital and if the DNSP cannot justify that it is efficient, it should not be included in the asset base of the DNSP.[2] CALC submitted that with under-spending, the AER should also assess whether it is a case of deferral.

Total Environment Centre (TEC) submitted that economic efficiency in the national electricity market (NEM) is already being distorted as regulation encourages inefficient infrastructure augmentation, such as the ex ante approach to capex, and the automatic roll in of actual capex, regardless of demonstrable optimisation.[3]

Energy Users Coalition of Victoria (EUCV) submitted that, because there is no ex post capex review under the NER, the risks to consumers arising from the NER are significant, as the AER's discretion is limited.[4] EUCV argued that there are risks that capex programs are inflated by the incentives determined by the Australian Energy Market Commission (AEMC) and Ministerial Council on Energy (MCE) Rule changes, and the RAB is inflated by regulatory gaming.

9.5 Issues and AER considerations

This section discusses Victorian DNSPs' roll forward calculations and the AER's considerations according to the following main issues:

- reconciliation of data with regulatory accounts and regulatory information templates
- penalties and rewards arising from correction of capex estimates used for 2005
- inflation applied throughout the RAB calculations
- Jemena's claim for the foregone return on capital associated with its capex overspend for the current regulatory control period
- related party profit margin
- decision to apply actual or forecast depreciation in the capex incentive framework for the forthcoming regulatory control period.

9.5.1 Data reconciliation

The AER has reviewed the Victorian DNSPs' inputs to their RFM calculations and cross checked them against the Victorian DNSPs' regulatory accounts and RIN

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2 Consumer Action Law Centre, *Submission to the Review of initial Distribution Network Service Providers' Proposals for the 201 15 Regulatory Period*, 16 February 2010, p. 28.

3 Total Environment Centre, *Submission to Australian Energy Regulator on Victorian electricity distribution network service providers' regulatory proposals*, 11 February 2010, p. 28.

4 Energy Users Coalition of Victoria, *Australian Energy Regulator Victorian Electricity Distribution Revenue Reset Applications from CitiPower, Jemena, Powercor, SP AusNet and United Energy – A response by Energy Users Coalition of Victoria*, February 2010 , pp. 19–20.

templates submitted as part of their regulatory proposals. For CitiPower and Powercor, the AER has had regard to the unaudited 2009 actual expenditure.

All Victorian DNSPs have used the RAB values specified in clause S6.2.1(c)(1) as opening values for 2006, and have adjusted these for the difference between actual and estimated capex (see section 9.5.2) which required disaggregated data for 2005.

AER considerations

The Essential Services Commission of Victoria's (ESCV) estimated capex values for 2005 were disaggregated for all asset categories except for transmission and distribution system assets. To deal with this information gap, the AER has applied the proportion of actual 2006 capex for these two asset categories for each Victorian DNSP to determine the 2005 estimated expenditure for these categories.

All Victorian DNSPs to varying degrees and for various years presented data which did not reconcile to Regulatory accounting statements and RIN templates. All discrepancies have been explained by the Victorian DNSPs which have either been accepted by the AER or resulted in minor adjustments to the RAB calculations as noted below.

Other specific issues identified for each Victorian DNSP are listed below.

CitiPower and Powercor

The AER identified small discrepancies in disposals for regulatory years 2005 to 2008 between regulatory accounts and the RFMs. CitiPower[5] and Powercor [6] explained that the RFM disposal values were sourced from the written down value of disposals which is no longer displayed in the Regulatory Accounts, but sits behind the calculation of profit/loss on sale of assets in the Regulatory Account templates. However the AER does not consider this valuation method to be appropriate, and has instead used asset sale proceeds as the value of disposals (i.e. the disposal data from regulatory accounts) as this is consistent with the approach used by the ESCV in its 2006 Electricity Distribution Price Review (2006 EDPR).

Jemena

The AER identified that Jemena's total estimated capex for 2005 was slightly different to that relied on in the ESCV's 2006 EDPR. Jemena has also included public lighting in the 2005 standard control benchmark capex, which should be under the alternative control service. The AER has applied the 2005 estimated capex as listed in the ESCV's 2006 EDPR.

The AER noted inconsistencies in capex data between Jemena's RFM and RIN templates for 2006–10. When asked about these inconsistencies, Jemena provided explanations which the AER accepted resulting in minor change to the RFM.[7]

SP AusNet

[5] CitiPower, *Response to AER information request*, 26 February 2010.
[6] Powercor, *Response to AER information request*, 26 February 2010.
[7] Jemena, *Response to AER information request*, attachment, 15 February 2010.

The AER identified differences between the capex data for 2005 to 2008 in SP AusNet's RFM and that in its RIN templates. SP AusNet noted that these differences related to the different treatment of customer connections and standard metering in the RIN, and SP AusNet has reconciled the RIN data inputs with the RFM data inputs.[8] The AER has therefore accepted the RFM data inputs.

AER conclusions

In general, where discrepancies were present between the data submitted in the Victorian DNSPs' RAB calculations and regulatory accounting statements, and were not adequately explained by the DNSPs, the AER has applied the latter as they are audited and prepared in accordance with the ESCV's *Regulatory Information Requirements Guideline No. 3 (Regulatory Accounting Guideline).* As a result, the AER has made minor amendments to some RFM calculations.

9.5.2 Adjustments arising from 2005 expenditure estimates

The Victorian DNSPs' proposed adjustments to the opening RAB to correct for the difference between the estimated and actual capital expenditure for 2005, and subsequent adjustments to the 2010 closing RAB (all converted into 2010 dollars) are set out in table 9.2. The calculated penalty (reward) reflects the additional (unearned) return on capital associated with the value of the overestimate (underestimate).

Table 9.2 Victorian DNSP proposed forecast and actual net capex adjustments for 2005 ($’m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Estimated	83.2	173.3	84.5	161.9	142.9
Actual	84.6	161.7	50.7	193.2	83.6
Difference	1.4	–11.6	–33.8	31.3	–59.3
Penalty/reward	–	–	–9.3	16.5	–

Source: Victorian DNSPs’ proposed RFMs.

AER considerations

The AER notes that these calculations are affected by the incorrect disaggregation of 2005 data for estimated capex and regulatory depreciation as discussed above. Also, the values proposed by SP AusNet and Jemena are affected by the incorrect method used to calculate actual inflation inputs to the RFM (discussed in section 9.5.3 below).

The AER also notes the following issues specific to each individual Victorian DNSP.

CitiPower

CitiPower's actual net capex for 2005 was $1.4 million ($2010) more than estimated, however no compound return on this difference was calculated in its RFM or in its

8 SP AusNet, *Response to AER information request*, 5 February 2010.

submission. CitiPower has subsequently indicated that it considers this adjustment was already made by the ESCV in the 2006 EDPR.[9]

Powercor

Powercor's actual net capex for 2005 was $11.6 million ($2010) less than estimated. As was the case with CitiPower, Powercor considered this adjustment had already been made by the ESCV.[10]

Jemena

Jemena's actual net capex was $33.8 million ($2010) less than estimated for 2005, and compound return on this difference was calculated in RFM. However the formula used to calculate this amount was incorrect. Its calculated compound return was not included in the RAB, rather it was included in the post-tax revenue model (PTRM) as a decrement to its building block revenue requirement for 2011.

SP AusNet

SP AusNet's actual net capex for 2005 was $31.3 million ($2010) more than estimated. The associated compound return was calculated in RFM and included in the submission as part of opening RAB in 2011. However the formula used to calculate this amount was incorrect.

United Energy

United Energy's actual net capex for 2005 was $59.3 million ($2010) less than the estimate. The associated compound return was calculated in RFM, but was not included in the submission as part of opening RAB in 2011.

AER conclusions

Based on the considerations above, the AER has adjusted the opening RAB for the Victorian DNSPs, under clause S6.2.1(c)(2), for the difference between the estimated and actual capital expenditure for calendar year 2005, and removed any benefits or penalties in the form of additional return on capital earned or forgone. These amounts have been added to/ deducted from the 1 January 2011 opening RAB for each Victorian DNSP for the forthcoming 2011–15 regulatory control period as shown in table 9.3.

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9 CitiPower, *Response to AER information request*, 8 February 2010, p. 4.
10 Powercor, *Response to AER information request*, 8 February 2010, p. 4.

Table 9.3 AER conclusion on forecast and actual net capex adjustments for 2005 ($’m, 2010)

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Estimate	83.2	173.3	83.5	161.0	142.9
Actual	84.4	160.2	50.7	195.7	83.6
Difference	1.2	–13.1	–32.8	34.7	–59.3
Penalty/reward	0.4	–4.3	–10.9	11.5	–19.7

Source: AER calculation.

9.5.3 Escalation rate for RAB roll forward

The NER provides that the roll forward of the RAB be adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism during the preceding regulatory control period.[11] The NER also requires the AER to specify in a building block determination the method of how indexation will be applied to the RAB.[12]

CitiPower, Powercor and United Energy have applied the Australian Bureau of Statistics (ABS) weighted average of eight capital cities, September to September annual CPI. This was consistent with the approach used by the ESCV in the 2006 EDPR for the current regulatory control period.

While SP AusNet has used this same data source, it has applied a March to September annual CPI for 2004 data values. Jemena has used a September to September annual CPI throughout its modelling, with a further forecast six month inflation to convert asset values from July 2010 to December 2010 dollar terms.

AER considerations

The AER questioned Jemena's and SP AusNet's rationale to include additional six months of inflation in their calculations. In its response, SP AusNet stated that there is no additional six months CPI as: [13]

- all the expenditure benchmarks set in the 2006 EDPR Final Decision are expressed in June 2004 dollars. For the purposes of the RIN, all these data need to be converted into December 2010 dollars to allow the like-for-like comparisons to be made with actual expenditure data
- all actual expenditures are expressed in nominal terms. For the purposes of the RIN, all these data also need to be converted into December 2010 dollars
- applying the 15 month lag methodology will generate the December 2010 dollars for the benchmark and actual expenditure to allow for like-for-like comparison.

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11 NER, cl. 6.5.1(e)(3).
12 NER, cl. 6.3.2(a)(2).
13 SP AusNet, *Response to AER information request*, 5 February 2010.

Jemena stated that its opening RAB for 1 January 2006 as set out in Schedule 6.2.1 of the NER is valued in June 2004 dollars. Therefore, to appropriately get a closing RAB as at 31 December 2010, in December 2010 dollars (as required by the AER's PTRM) Jemena has escalated the opening RAB for 1 January 2006 by six and a half years over the period.[14]

The AER notes that all data in the 2006 EDPR were expressed in real 2004 dollars. The expression of data as at '1 July 2004' in the ESCV's 2006 EDPR reflects the fact that cashflows are assumed to be incurred evenly throughout the year (approximated by a mid year value assumption) and does not imply that data was literally valued as at 1 July 2004. While this is somewhat confusing, the AER has examined the ESCVs' models and confirms that costs prior to 2004 were escalated by the annual CPI as per the control mechanism, which used a September CPI value. In other words, to maintain consistency with the lagged September CPI data used in the control mechanism, this September CPI was used to approximate middle of the year (1 July) values.

Similarly, the inflation adjustment of the RAB proposed by Jemena is incorrect because the annual CPI adjustment is also approximated by September inflation which will be applied to the PTRM. That is, by applying an additional 6 months inflation, Jemena's proposal creates an inconsistency between inflation as applied in the roll forward and in the AER's PTRM.

The need for consistency has been implicitly recognised by CitiPower, Powercor and United Energy who have escalated nominal costs for the period 2005 to 2010 by annual CPI (September on September) to convert them to real 2010 dollars.

Overall, the AER notes that the ESCV's modelling involves a consistent treatment of CPI between building block revenue requirements, asset values and the CPI-X price control. The AER expects to maintain this consistency throughout the forthcoming 2011–15 regulatory control period, by continuing to apply the ESCV's indexation methodology for the current control mechanism and in the subsequent roll forward calculations under clauses 6.5.1(e)(3) and 6.3.2(a)(2).

AER conclusions

The AER has removed the additional CPI applied by SP AusNet (for 2004 data) and Jemena (for 2010 data) as this is inconsistent with the escalation of the current regulatory control period's control mechanism.

9.5.4 Financing cost of capex overspend

This section specifically addresses Jemena's proposed financing cost for its capex overspend for the current regulatory control period. Jemena has requested the associated foregone return on capital of $12.4 million to be included as a revenue increment in accordance with the 2006 EDPR.[15]

In its final determination the ESCV set capex allowances for all five Victorian DNSPs as 30 per cent above their reported historic expenditures for the 2001–05 regulatory

[14] Jemena, *Response to AER information request*, 2 March 2010.
[15] Jemena, *Regulatory proposal 2011–2015, November 2009.* p. 213.

control period. In combination the ESCV suggested that DNSPs overspending their allowances should be able to recover the foregone return on capex, limited by a 'cap' reflecting the expenditure amounts recommended by its consultant at the time.[16]

Jemena subsequently overspent its capex by $95.8 million ($2010) for the 2006–10 regulatory control period and stated that this was due to out-turn customer growth which led to significantly higher customer initiated capex than was contemplated by the ESCV's consultants. Jemena claimed that the circumstances giving rise to its capex overspend and the fact that this overspend was within the determined 'expenditure cap', warrant the AER providing financing costs on this amount.[17]

Jemena submitted further information arguing that this adjustment is required to ensure 'a reasonable opportunity to recover at least the efficient costs as required by the revenue and pricing principles of the NEL in section 7A(2)'. Jemena also argued that the recovery of the financing costs associated with additional capital expenditure contemplated by the ESCV in the 2006 EDPR is a control mechanism for the purposes of clauses 6.4.3(a)(6) and 6.4.3(b)(6) of the NER.[18] It also stated that the financing cost recovery constitutes a transitional matter in accordance with the terms of the AER's RIN.

In addition, Jemena has provided its overspend over the current regulatory control period by AER RIN category, with brief explanations for each category.

AER considerations

While the ESCV may have had some expectation that it or the AER would perform an ex post assessment of the actual capex spent by all Victorian DNSPs for the 2006–10 regulatory control period, no provision for such a review or any compensatory adjustments were provided for in chapter 6 of the NER. In particular, financing costs associated with capex overspends do not form part of the calculations described in schedule S6.2 of the NER. Such provisions are notably absent from chapter 11 of the NER (relating to transitional rules specific to the Victorian determination) where other provisions preserving the ESCV's approach are contained, for example with respect to tax depreciation methods.

Furthermore, the rolling forward of financing costs contemplated by the ESCV is not a control mechanism, as suggested by Jemena. The AER also notes that recognising financing costs associated with overspends is entirely inconsistent with the capex incentive framework as it reduces the incentive to seek efficiencies.

AER conclusions

The financing costs associated with Jemena's additional capital expenditure incurred in the current regulatory control period have not been rolled into the RAB for the 2011–15 regulatory control period.

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16 ESCV, *Electricity Distribution Price Review 2006–10 October 2005, Final Decision Volume 1*, p. 271.

17 Jemena, *Regulatory proposal*, pp. 212–3.

18 Jemena, *Response to AER information request*, 15 February 2010.

9.5.5 Related party profit margin adjustment

This section deals with related party profit margins which have been included in the capital expenditure for the RAB roll forward. The AER's treatment of related party margins is discussed more generally in chapter 6 of this draft decision (Outsourcing and related party transactions chapter).

The amount of margins and management fees paid by the Victorian DNSPs to related entities characterised as capex over the current regulatory control period is set out in table 9.4.

Table 9.4 Victorian DNSP margins paid to related entities and capitalised over 2006–10 ($'m, 2010)

	Total capex with margin	Total capex without margin	Margins
CitiPower	485.5	461.8	23.7
Powercor	927.2	895.9	31.3
Jemena	337.2	330.4	6.8
SP AusNet	707.2	705.4	1.8
United Energy	608.3	604.1	4.2

Source: Victorian DNSPs' RIN templates.

The AER notes that such amounts were excluded from the Victorian DNSPs' capex allowances by the ESCV for the current regulatory control period, on the basis that these arrangements have the potential to allow for a greater than intended proportion of the benefits of any efficiency gains to be retained within the corporate group.[19] This characterisation of margins was reflected in amendments to the ESCV's Guideline 3, where it required the Victorian DNSPs to report expenditures net of margins to related parties as they were regarded as not reflecting the costs of providing regulated services.[20]

In making this draft decision the AER has carefully examined the nature of related party margins with respect to the recognition of 'all capital expenditure incurred' under clause S6.2.1(e)(1). In particular, the AER has considered the extent to which the margins paid would be characterised as inefficient capital expenditure (that is, the amount was simply above what would have been incurred in a competitive market) or whether they were so excessive as to have no relationship to the services provided by the related party or the DNSP (and therefore not simply inefficient, but not 'capital expenditure' at all). The AER notes that margins and management fees paid by United Energy and Jemena to a related service provider, Jemena Asset Management, were explored by the Australian Competition Tribunal in its recent ruling on the

[19] ESCV, *Electricity Distribution Price Review 2006-2010 Volume 1*, October 2006, p. 169.

[20] ESCV, *Final decision on Revisions to guideline no. 3 regulatory accounting information requirements*, December 2006, p. 13.

appeal of the AER's October 2009 AMI Determination.[21] The AER notes that the tribunal stated that the DNSP's expenditure will necessarily incorporate a margin it pays to the party providing outsourced services.

The presumption in this clause that the AER will automatically recognise all amounts in the DNSPs' RAB roll forward calculations highlights a potentially serious issue with the capex incentive framework under chapter 6 of the NER. This issue was raised with respect to capex generally in submissions by the CALC, TEC and EUCV as discussed above.

The apparent requirement for the AER to automatically accept all amounts characterised as capex under clause S6.2.1(e)(1) creates an incentive for DNSPs to enter into related party contracts and seek outcomes contrary to the efficiency objectives of the regulatory framework. For example, a DNSP may present contract costs as actual capital expenditure, yet actual costs of service delivery incurred by the related party may be lower due to efficiency gains or because of an inflated contract charge. In this situation, where contract costs are rolled into the RAB, these efficiency gains are retained by the ultimate owner(s) of both entities and there is no incentive for these gains to be passed back to consumers.

In the case of opex allowances, incentive carryover mechanisms and the setting of allowances based on underlying costs (not simply contracted rates) ensure that efficiency gains are retained by the DNSP for an appropriate amount of time then passed to end users. However, in the case of capital expenditures, while regulators are able to set allowances that are reflective of efficient costs on an ex ante basis, there are no checks on an ex post basis to ensure the DNSPs are being rewarded/ penalised for bona fide efficiency gains or losses. While there is a clear policy intention to not undertake ex post efficiency assessments of capital expenditure, the AER considers that the NER framework needs to address any incentives that a DNSP and its related party may have to capitalise amounts which bear no relationship to actual costs.

A similar potential for the Victorian DNSPs to game the capex incentive arrangements arises where a DNSP proposes (and is provided) certain amounts as opex on an ex ante basis, then through changes to capitalisation policies, characterises amounts as actual capex for rolling into its RAB. In this way, the DNSP would be compensated for in its opex allowance and again through depreciation and returns on capital once the amount is recognised as actual capex. In this case, there has been no change in the underlying capital cost of service delivery, hence the DNSP would not be penalised for incurring actual ‘capex’ above the benchmark. It should be noted that the AER and other regulators have recognised this issue in developing ex post adjustments under opex incentive mechanisms, whereby gaming through changes to capitalisation are neutralised. There are, however, no corresponding adjustments to capex allowances that are rolled into the asset base.

Therefore, in the same way that there are checks to ensure DNSPs have the correct incentives to minimise their costs under the opex incentive regime, the AER considers that similar checks should be a feature of the capex incentive regime. The issue of symmetry between capex and opex incentives (noted in the case of capitalisation

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21 Application by United Energy Distribution Pty Ltd [2009] ACompT 10.

policy changes) may be addressed by extending the AER's EBSS to capex as provided for under the NER. The AER considers, however, that the capitalisation of related party margins gives rise to more fundamental issues relating to the requirements of clause S6.2.1(e)(1), which would require changes to the NER (including to the equivalent provisions in chapter 6A).

In conclusion, for the purposes of this decision the AER has not sought to make adjustments to the Victorian DNSPs' roll forward calculations with respect to related party margins.

9.5.6 Decision to apply actual or forecast depreciation

Clause 6.12.1(18) of the NER requires the AER to determine whether the depreciation for establishing the opening RAB for the following regulatory control period (that is, as at 1 January 2016), is to be based on actual or forecast capex (referred to here as the use of actual or forecast depreciation). The Victorian DNSPs did not address this matter in their regulatory proposals.

AER considerations

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.

The NER does not offer any criteria regarding the decision to use 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 efficiency improvements or whether they 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. The use of actual depreciation is also consistent with transmission regulation (prescribed in chapter 6A) and also the AER's recent distribution determinations in New South Wales Australian Capital Territory, Queensland and South Australia.

As indicated in section 9.4 above, several stakeholders consider that the incentive framework for capex is relatively weak as it does not provide for ex post assessments. The AER also shares this concern. As noted in section 9.5.5 above, the general incentives on capex and opex are imbalanced, particularly under the arrangements put in place by the ESCV where depreciation does not form part of the incentive framework.

AER conclusions

In this context, the AER considers it important to provide effective incentives for Victorian DNSPs to seek out efficiencies wherever possible in its capex programs, and that a higher powered incentive is therefore appropriate. The AER therefore determines that actual depreciation will be used to establish the opening RAB for the 2016–20 regulatory control period for the Victorian DNSPs.

9.6 AER conclusion

The AER has determined the closing RAB (nominal) for each year of the current regulatory control period by:

- increasing the opening RAB by the amount of capex incurred net of customer contribution (including estimated capex for the remaining part of the current regulatory control period) and adjusted for actual CPI
- reducing the opening RAB by the amount of regulatory depreciation allowed in the ESCV's 2006 EDPR, adjusted for actual CPI
- reducing the opening RAB by the sale 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 2001–05 regulatory control period and actual capex for that part of the period, and the return on the difference.

Applying the RFM, the Victorian DNSPs derived an opening RAB as at 1 January 2011 as detailed in table 9.1. The AER has reviewed Victorian DNSPs' proposed opening RAB and the cost inputs to the RFM for the current regulatory control period and has cross checked these against their regulatory accounts. The AER has identified issues related to the Victorian DNSPs' RAB forward models as follows, and made adjustments to RAB accordingly, in relation to:

- reconciliation of data inputs (as noted in section 9.5.1)
- adjustments arising from 2005 expenditure estimates (9.5.2)
- escalation methodology for the RAB forward model (as noted in section 9.5.3)
- financing cost for capex overspend (as noted in section 9.5.4).

For the purposes of this draft decision (and in accordance with clause 6.12.1 (6) of the NER), the AER has applied an opening RAB for Victorian DNSPs as at 1 January 2011, as set out in table 9.5. This value is used as an input to the PTRM for the purposes of determining Victorian DNSPs' annual revenue requirement during the forthcoming regulatory control period.

The AER has also determined, under clause 6.3.2(a)(2) of the NER, that it will apply the same method to index the RAB as that used to escalate the form of control mechanism over the forthcoming regulatory control period. This will form part of the calculation of the opening RAB in the AER's distribution determination for the 2016–20 regulatory control period.

In accordance with clause 6.12.1(18) of the NER, the AER will use actual depreciation for establishing the RAB for the commencement of the 2016–20 regulatory control period.

The AER's decision on the opening RAB can also be found in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

Table 9.5 AER conclusion on Victorian DNSPs' opening RAB ($’m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Opening RAB	1 176.8	1 194.1	1 197.6	1 206.5	1 233.5
Net capex	93.6	79.1	84.6	97.5	124.7
Depreciation	–76.3	–75.7	–75.6	–70.5	–72.0
Compound return on 2005 capex difference					0.4
Closing RAB	1 194.1	1 197.6	1 206.5	1 233.5	1 286.5
Difference from proposed RAB					–4.5
Powercor					
Opening RAB	1 916.8	1 978.7	2 034.4	2 093.0	2 136.2
Net capex	182.0	176.5	181.0	168.2	199.1
Depreciation	–120.1	–120.9	–122.4	–124.9	–126.1
Compound return on 2005 capex difference					–4.3
Closing RAB	1 978.7	2 034.4	2 093.0	2 136.2	2 204.9
Difference from proposed RAB					–11.7
Jemena					
Opening RAB	653.4	673.9	695.0	691.1	708.3
Net capex	63.2	65.5	41.2	63.6	91.7
Depreciation	–42.7	–44.3	–45.1	–46.3	–46.8
Compound return on 2005 capex difference					–10.9
Closing RAB	673.9	695.0	691.1	708.3	742.2
Difference from proposed RAB					–13.4
SP AusNet					
Opening RAB	1 585.7	1 631.0	1 676.0	1 775.8	1 935.8
Net capex	129.3	137.6	198.2	263.8	256.1
Depreciation	–84.0	–92.5	–98.5	–103.7	–109.2
Compound return on 2005 capex difference					11.5
Closing RAB	1 631.0	1 676.0	1 775.8	1 935.8	2 094.2
Difference from proposed RAB					–13.1
United Energy					
Opening RAB	1388.6	1381.5	1359.0	1334.3	1365.1
Net capex	97.7	83.9	85.4	124.2	124.9
Depreciation	–104.8	–106.4	–110.1	–93.4	–82.6
Compound return on 2005 capex difference					–19.7
Closing RAB	1 381.5	1 359.0	1 334.3	1 365.1	1 387.7
Difference from proposed RAB					–19.8

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). 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.

This chapter is mainly concerned with the AER's assessment of each of the Victorian distribution network service providers' (DNSPs') proposed asset lives used to calculate their depreciation schedules for the forthcoming regulatory control period.

10.2 Regulatory requirements

Under clause 6.12.1(8) of the National Electricity Rules (NER), the AER must make a decision on whether or not to approve the depreciation schedules submitted by the DNSP and, if the AER decides against approving them, a decision determining depreciation schedules in accordance with clause 6.5.5(b).

Clause 6.5.5 of the NER sets out the requirement for depreciation for each regulatory year. Clause 6.5.5(a)(1) of the NER provides that depreciation must be calculated on the value of the assets included in the RAB at the beginning of the regulatory year.

A building block proposal must contain depreciation schedules that conform to the following requirements set out in clause 6.5.5(b) of the NER:

1. the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;
2. the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of the asset or category of assets was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system;
3. the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

10.3 Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed regulatory depreciation allowances as calculated by the post-tax revenue model (PTRM) are set out in table 10.1.

Table 10.1 Victorian DNSP proposed regulatory depreciation ($'m, nominal)

	2011	2012	2013	2014	2015	Total
CitiPower	33.2	36.7	40.2	44.2	49.3	**203.5**
Powercor	64.3	72.7	81.2	90.3	101.5	**410.0**
Jemena	28.4	34.4	40.7	40.7	39.2	**183.4**
SP AusNet	95.9	62.6	70.1	74.6	64.9	**368.1**
United Energy	51.7	56.4	63.0	67.6	72.3	**310.5**

Source: DNSPs' PTRMs.

All the Victorian DNSPs proposed to continue using a straight line methodology for calculating depreciation in relation to the opening RAB for the forthcoming regulatory control period. Further to the depreciation calculations arising from the PTRM inputs and methods, United Energy proposed additional regulatory depreciation amounting to $51.63 million ($ real 2010) over the forthcoming regulatory control period.

Each Victorian DNSP proposed to maintain the same asset categories as those approved by the Essential Services Commission of Victoria (ESCV) for the 2006–10 regulatory control period, with the addition of a new asset category for equity raising costs proposed by CitiPower, Powercor and Jemena.

CitiPower, Powercor and United Energy proposed to apply the same standard asset lives for the 2011–15 regulatory control period as apply for the current regulatory control period. SP AusNet and Jemena proposed different standard asset lives for the 2011–15 regulatory control period compared to those approved by the ESCV for the current regulatory control period.

The Victorian DNSPs' proposed regulatory asset categories and standard lives are set out in table 10.2.

Table 10.2 Victorian DNSP proposed standard asset lives (years)

Asset category	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Subtransmission	50.0	50.0	47.3	45.0	60.0
Distribution system assets	49.0	51.0	46.8	50.0	35.6
Standard metering	–	–	–[1]	–	–
Public lighting	–	–	–	–	–
SCADA/Network control	13.0	13.0	30.5	5.0	5.0
Non network general assets—IT	6.0	6.0	5.0	5.0	5.0
Non network general assets—other	10.0	15.0	18.9	1.0	7.5
Equity raising costs	48.9	46.2	42.0	–	–

Source: DNSPs' PTRMs.

10.4 Summary of submissions

The Energy Users Coalition of Victoria (EUCV) commented that it has been observed by many businesses that recovery of depreciation is usually less than the actual investment made, and that this observation is predicated on the nominal value of depreciation as used by the ATO. In a regulated environment the 'real' value of depreciation is incorporated in the building block, increasing the costs to consumers. The EUCV commented that competition does not appear to allow DNSPs to recover

[1] Standard lives for new standard metering and public lighting assets are not applicable as these assets are no longer considered assets used to provide standard control services and hence are not included in the RAB. The DNSPs have maintained asset categories for standard metering and public lighting in order to calculate depreciation of these assets prior to them becoming excluded from the RAB. In its Final Decision, the ESCV stated that:

> To address the potential for stranded asset risk associated with accumulation meters with the mandated rollout of interval meters the Commission, consistent with the methodology proposed in its final framework and approach, will provided that the asset base for these meters installed prior to 1 January 2006 will remain in the regulated asset base for DUoS charges. The financing costs associated with these assets will continue to be recovered through distribution use of system tariffs.

The ESCV in its public lighting information sheet also states that:

> With the disaggregation of the public lighting OMR charges from DUoS charges, the financing costs associated with public lighting assets in the distributor's asset base as at 1 January 2001 continue to be recovered through DUoS charges.

depreciation (either nominal or real values) therefore the AER must be particularly aware of the potential to game the depreciation of regulated assets.[2]

The EUCV further noted that with a WACC higher than what the market as a whole achieves, there is a commercial driver for a regulated business to physically dispose of assets before their technical life may be over. This driver is unique to the building block approach to revenue setting in that a fully depreciated asset does not attract any return, whereas replacing a written off asset does attract a return as it is not yet fully depreciated for regulatory purposes. In a competitive business, writing off an asset is seen as a positive if the asset is still used as the costs of production are lower.[3]

The EUCV notes that each DNSP has a different depreciation schedule for the same asset class and it considers this unacceptable. The EUCV noted that in theory each asset will have the same regulatory life regardless of the owner, provided all owners apply best practice to maintain the asset, especially in Victoria which is geographically the smallest mainland state, and therefore there are only small differences in climatic conditions which might impact an asset life. The EUCV considered that the AER should set the same asset life to each asset class regardless of which DNSP owns the asset.[4]

10.5 Issues and AER considerations

The allowance for regulatory depreciation is an output of the PTRMs submitted by the Victorian DNSPs and as such is based on the straight line depreciation method that forms part of the AER's published PTRM. The relevant inputs to the PTRM's calculation of an allowance for regulatory depreciation include the categories of assets, standard and remaining lives for each asset category, and the opening RAB and forecast capex for each category.

Depreciation rates impact the timing of cash flows to the DNSPs and may also have implications for the intergenerational burden on customers. The EUCV’s concern regarding the premature replacement of assets relates to whether customers are contributing to an efficient amount of returns of capital.

In its review of proposed depreciation schedules the AER has focused on the asset lives proposed by each of the Victorian DNSPs and had regard to comments from the EUCV regarding incentives underlying proposed lives and the implications for long term prices. The AER also had regard to the historical depreciation profiles arising from previous regulatory control periods and their respective distribution determinations.

The value of regulatory depreciation as a percentage of the asset base provides a measure to examine consistency and stability in depreciation rates and methods over time, notwithstanding changes in the composition of the asset base. The percentages

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2 Energy Users Coalition of Victoria (EUCV), *Victorian Electricity Distribution Revenue Reset: Applications from CitiPower, Jemena, Powercor, SP AusNet and United Energy,* February 2010, p. 36.

3 ibid., p. 37.

4 ibid., p. 38.

for previous regulatory control periods (based on regulatory determinations) and for the forthcoming regulatory control period (based on the DNSPs' proposals) are set out in table 10.3.

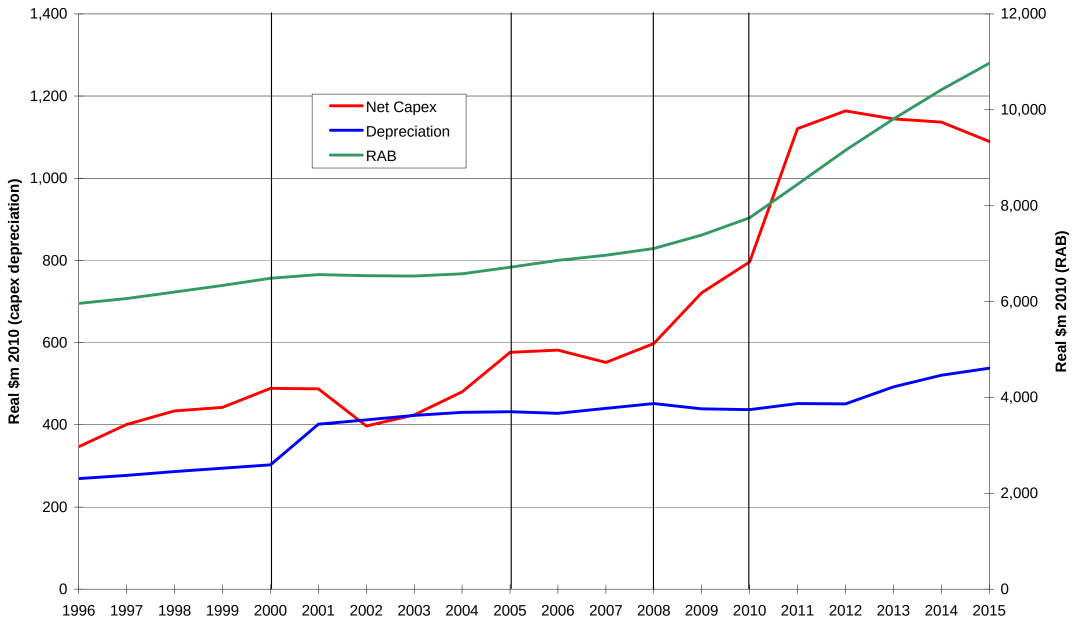
Table 10.3 Regulatory depreciation as a percentage of regulatory asset base, historic and forecast (per cent)

	1994–2000	2001–05	2006–10	2011–15
CitiPower	4.2	4.8	5.9	4.8
Powercor	5.1	7.1	5.9	5.3
Jemena	5.2	6.3	6.4	6.1
SP AusNet	4.2	5.6	5.8	5.2
United Energy	4.5	6.3	6.8	6.0

Source: AER analysis.

This analysis shows that since 1994 all of the Victorian DNSPs except Powercor have been depreciating their assets at a progressively faster rate. This trend is further illustrated for the combined Victorian DNSPs in figure 10.1 where there was a significant increase in the rate of depreciation from 2001. Depending on the rate of replacement of older assets, where networks are expanding to meet new demand one would expect the value of the RAB to steadily increase over time, however the figure below shows the combined RAB value of the Victorian DNSPs to be relatively flat from 2000 to 2008.

Figure 10.1 Victorian DNSP combined regulatory depreciation, capex and RAB



Source: AER analysis.

This may indicate that assets are being depreciated faster than their economic life, and/or that the new assets being installed in each period have shorter expected lives than those already in the RAB.

In its review of depreciation for the 2006–10 regulatory control period, the ESCV did not require the adoption of a standardised set of asset lives or asset classes. This 'hands off' approach to determining regulatory depreciation was based on the ESCV's view that the rate of depreciation affects only the timing (rather than value) of cash flows.[5] The ESCV further commented that the choice of depreciation rates will affect the stability of prices over time.[6]

Accordingly, in reviewing depreciation rates for the forthcoming regulatory control period, the AER is mindful that the asset lives used in previous regulatory control periods and those proposed may not be consistent with expected economic/technical lives. The AER also notes the NER requirement under clause 6.5.5(b)(1) did not apply in previous regulatory control periods, namely that:

> 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

Satisfaction of this requirement would address the concerns raised by stakeholders about the premature replacement of assets. In this context, the AER also notes that in its review of the replacement practices of each DNSP, and also in the models used to calculate remaining lives for their assets, there are many instances of assets still being used beyond their expected economic lives. Similarly, there are instances of assets being replaced earlier than expected due to failure or other condition related issues. The replacement of assets is further discussed in the AER's assessment of the Victorian DNSPs' capital expenditure proposals in chapter 8.

In considering the proposed asset lives the AER notes the potential exists for DNSPs to gain by proposing capital expenditure allowances for short lived asset categories but then actually spend capex on long lived assets. This would have the effect of increasing the regulatory depreciation allowance set on a prospective basis, but having a lower amount of actual depreciation incurred, and increasing the overall value of assets that is ultimately rolled into the RAB.

To address this problem the AER has, in accordance with clause 6.5.5(b) of the NER, reviewed the nature of the assets within each asset category and considered the proposed depreciation profiles accordingly. As a result, the AER has made some changes to the asset lives proposed by each DNSP (discussed in the following sections).

In reviewing the asset lives proposed by the Victorian DNSPs, the AER also considered the comment by the EUCV that the AER should set the same asset life to each asset class regardless of which DB owns the asset.[7] While the AER has made

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5 ESCV, *Electricity Distribution Price Review 2006–10 Final decision*, Volume 1, October 2006, p. 328.

6 ibid., p. 329.

7 EUCV, *Submission to the AER*, p. 38.

some changes to the asset lives proposed by the Victorian DNSPs, they still differ between DNSPs, with some asset lives for different categories differing significantly. These differences reflect the aggregated nature of the depreciation calculations for regulatory purposes. The notion of an 'economic life' for classes of assets as used in clause 6.5.5(b) implies the monitoring of installation dates and the lives of assets, which is done at a high level by the DNSPs. This gives rise to inconsistencies in approach, including in how assets are grouped into aggregated classes.

In this context the AER considers there may be merits in considering alternatives with respect to how assets as classified for depreciation purposes. For example, combining all assets into a single asset category would remove the incentive to change the mix of assets within categories. It would also have the added benefit of avoiding administrative burden in justifying and scrutinising standard and remaining asset lives for each asset category. However, the introduction of a single asset category could potentially remove the degree of granularity required to satisfy clause 6.5.5(b) of the NER. An alternative option to addressing inappropriate reclassification of assets may be to increase the number of categories, so that the categories are more defined. This would also allow for more standardised lives across the Victorian DNSPs. The AER has not pursued changes to asset classes in this decision, noting that, in this instance, such changes are not necessary to satisfy the NER requirements and are something more appropriately considered as part of a wider consultation process (for example, as part of potential amendments to the AER's PTRM and RFM).

10.5.2 Depreciation method

Regulatory depreciation has been calculated by the PTRM on the basis of each DNSP's proposed remaining and standard asset life inputs, and the opening RAB (discussed in chapter 9) and forecast capex values.

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. This approach differs from previous regulatory determinations under the ESCV, where annual depreciation recognised capital expenditure during the relevant year.

Consistent with clause 6.5.5(a) of the NER each DNSP has calculated depreciation on the value of the assets included in the RAB at the beginning of the year as opposed to recognising capital expenditure during the relevant year.

In using the AER's PTRM, all Victorian DNSPs propose to continue to apply a straight line methodology for calculating depreciation, which is consistent with the AER's default depreciation method and is therefore accepted for the purposes of this determination. DNSPs are able to amend the PTRM to incorporate depreciation profiles other than the straight line method, subject to assessment in accordance with clause 6.5.5 of the NER.

The additional depreciation proposed by United Energy for sub-transmission and distribution system assets reflects a departure from the straight line depreciation methodology. In justifying this additional depreciation, United Energy refer to a transitional issue arising from the ESCV's previous approach to depreciation:[8]

> Compared to Rule 6.5.5, the ESC's regime provided a much greater degree of flexibility in calculating annual depreciation. A transitional issue therefore arises in moving from the ESC's regime to the new regime required by Rule 6.5.5. For United Energy, the ESC accepted a comparatively long asset life (compared to the economic life) and low rate of depreciation for some asset categories. The effect of the longer asset life adopted in the 2005-2010 determination is that some assets will be replaced in the forthcoming regulatory period prior to the end of their notional lives….
>
> One approach to addressing this issue is to write off the remaining value of these assets over a more appropriate, shorter estimated remaining life. The difficulty with this approach, however, is that the net book value of assets that are no longer in service will be recovered over many years, which would be contrary to the requirements of Rule 6.5.5(b)(1). In particular, it would be difficult to argue that a depreciation profile that recovered capital costs for assets that no longer provided service properly reflected the nature of the assets over their economic life.

Essentially what United Energy is proposing is an accelerated depreciation of its subtransmission and distribution assets. The AER considers that a better way for United Energy to address this issue is to make adjustments to the remaining lives of assets. The AER considers that this is the appropriate method to address instances of assets having residual value for regulatory purposes at the time they are replaced. In particular, the AER has several concerns with United Energy's justification:

- United Energy's rate of depreciation for its overall RAB over the 2006–10 regulatory control period was the highest of the Victorian DNSPs (see table 10.3 above). In viewing the data presented above, the ESCV's 'hands off' approach appears to have resulted in progressively faster rates of depreciation for all the Victorian DNSPs. In such a situation, one would expect any transitional issues to arise in the need to reduce the rate of depreciation, not increase it

- Using data from the ESCV's 2006 determination, the AER has calculated that the implied remaining asset life for United Energy's subtransmission assets was 43.3 years as at 2006. This compares to the much lower remaining life of 24.0 years from 2011 that United Energy now proposes to the AER. This will have the effect of significantly increasing the rate of depreciation for the forthcoming regulatory control period

- modelling provided by United Energy shows that the calculation of its remaining lives already takes into account the full range of assets in service, some of which have lasted longer and shorter than their expected lives. As noted in section 1.5.3 below, the AER has assessed United Energy's methods for calculating the lives in its proposal and has accepted them as reasonable.

The AER considers that United Energy's additional depreciation has not been adequately justified as being in accordance with the requirements of clause 6.5.5(b)(1)

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[8] United Energy, *response to further asset modelling questions*, email to AER staff, 19 March 2010.

and is not accepted by the AER. The making of ad hoc and large 'write offs' does not result in a depreciation profile that reflects the nature of United Energy's asset categories.

10.5.3 Asset classes, standard asset lives and remaining asset lives

This section examines the standard and remaining lives proposed by each DNSP in turn. For all Victorian DNSPs the AER notes that the calculation of each DNSP's remaining lives have been based on opening RAB values for 2011, which have been affected by the AER's determination (refer to chapter 9).

Jemena regulatory proposal

Jemena's proposed asset lives are set out in table 10.4. Jemena proposed different standard asset lives for new capex compared to the current regulatory control period and an additional new asset category for equity raising costs. The AER has previously accepted that equity raising costs for new issuance are a legitimate cost for a benchmark efficient firm where external equity funding is the least cost option available. Accordingly, the AER considers the capitalisation and depreciation of these values to be consistent with regulatory practice. Equity raising costs are discussed in detail in Appendix E.

Table 10.4 Jemena proposed standard and remaining asset lives (years)

Asset category	2006–10 standard asset lives for new capex	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	56.4	47.3	29.1
Distribution system assets	51.8	46.8	21.0
Standard metering	N/A	N/A	4.4
Public lighting	N/A	N/A	8.3
SCADA/Network control	5.0	30.5	30.5
Non-network general assets – IT	5.5	5.0	3.2
Non-network general assets – other	9.2	18.9	15.5
Equity raising costs	0	42.0	0

Source: Jemena roll forward model and PTRM.

AER considerations—Jemena's standard lives

The AER queried Jemena's proposed change to standard asset lives for new capex for the forthcoming regulatory control period compared to the current regulatory control period. Jemena responded that the depreciation lives are the average asset lives weighted against the capex within an asset category. Jemena submit that because the asset mix in the forthcoming regulatory control period differs from the current regulatory control period, the weighted average asset lives differ from those calculated for the current regulatory control period.[9] In a further response Jemena re-emphasised that the capital expenditure profile in its 2004 submission to the ESCV is considerably different from that in Jemena's current regulatory proposal. In addition, Jemena provided information to show that the calculation of weighted average lives for its 2004 submission differs from the method used in the current regulatory proposal. Jemena commented that if the same method was used for the current regulatory proposal as was used for the 2004 submission, the weighted average lives for the current regulatory proposal would have been shorter than the proposed 47.3 years (sub transmission) and 46.8 years (distribution system assets).[10]

The AER also queried why the proposed standard life for SCADA / Network control for 2011–15 increased to 30.5 years compared to the current standard life of 5 years, and similarly why the standard life for 'non-network general assets-other' for the forthcoming regulatory control period of 18.9 years increased from 9.2 years for the current regulatory control period. Jemena responded that the ESCV approved the 5 years standard life for SCADA considering the:

> technical life of SCADA equipment was considered to be much shorter than 20 years, because hardware upon which it is built rarely has an available life longer than four years, thereby resulting in shorter manufacturer support periods. (pg 328, Final Decision 2006, ESCV)'.[11]

Jemena commented that for the forthcoming regulatory control period, the SCADA standard life of 30.5 years is derived based on the weighted average lives of the two asset classes fall into the SCADA asset category, that is, Supervisory Cable - Fibre Optic (40 years) and SCADA - Communications equipment (20 years).[12]

Jemena commented that the increase in the standard life for non-network general assets-other is that long life assets (for example, building with 50 years life) form a significant portion of the capex for non-network general assets-other. It therefore arithmetically increases the weighted average depreciation life for the asset category.[13]

The AER considers that Jemena's proposed standard lives reflect the economic lives of those assets and results in a depreciation profile that is in accordance with clause 6.5.5(b)(1) of the NER.

AER considerations—Jemena's remaining lives

The AER notes that Jemena's remaining life calculations with respect to 2010 expenditure data applies an average of the remaining lives approved by the ESCV for this year with the remaining lives it proposes for the forthcoming regulatory control period. In other words, this methodology results in the calculation of remaining lives for the RAB based on two sets of different asset lives. In effect this appears to reflect

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9 Jemena, email to AER staff, 15 Feb 2010.
10 Jemena, email to AER staff, 25 March 2010.
11 Jemena, email to AER staff, 15 Feb 2010.
12 Jemena, email to AER staff, 15 Feb 2010.
13 Jemena, email to AER staff, 15 Feb 2010.

an assumption (as applied by the ESCV) that capex is spent evenly throughout the year.[14]

The AER considers that in calculating the remaining lives that all 2010 capex should be assigned the standard lives approved by the ESCV for the 2006–10 regulatory control period, rather than a combination of this and Jemena's proposed standard lives for the forthcoming regulatory control period. Accordingly, the AER has made minor amendments to Jemena's proposed remaining asset lives as set out in table 10.5.

Table 10.5 AER conclusion on remaining asset lives for Jemena (years)

Asset category	Jemena proposed remaining asset lives	AER calculation of remaining asset lives
Subtransmission	29.1	28.3
Distribution system assets	21.0	21.1
Standard metering	4.4	4.4
Public lighting	8.3	9.8
SCADA/Network control	30.5	5.0
Non-network general assets—IT	3.2	4.1
Non-network general assets—other	15.5	12.9

CitiPower regulatory proposal

CitiPower's proposed asset lives are set out in table 10.6.

14 When modelled, half of the expenditure reported for a particular year is presumed to occur on the first day of that year, with the remainder presumed to occur on the last day.

Table 10.6 CitiPower proposed standard and remaining asset lives (years)

Asset category	2006–10 standard asset lives for new capex	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	50.0	50.0	22.7
Distribution system assets	49.0	51.0	22.9
Standard metering	N/A	N/A	6.1
Public lighting	N/A	N/A	14.1
SCADA/Network control	13.0	13.0	7.6
Non-network general assets—IT	6.0	6.0	5.2
Non-network general assets—other	10.0	10.0	8.5
Equity raising costs	–	48.9	–

Source: CitiPower roll forward model and PTRM.

AER considerations—CitiPower standard lives

CitiPower proposed standard asset lives for new capex for distribution system assets of 51 years and non-network general assets-other of 15 years. The AER found that these asset lives differed to that in the current regulatory control period of 49 years and 10 years respectively. CitiPower responded that the proposed roll forward model had incorrectly applied the Powercor Australia distribution system asset life and non-network general asset standard life.[15] The AER has applied this correction in determining CitiPower's depreciation allowance.

AER considerations—CitiPower remaining lives

Both CitiPower and Powercor use the same current cost accounting depreciation methodology to calculate their remaining asset lives. The AER found this methodology the most thorough of the Victorian DNSPs.

In simple terms this methodology first takes the written down value (WDV) of the assets as at 1994. The remaining life for these assets is then determined by multiplying the standard asset lives for each asset category by 49.6 per cent, (which is the ratio of SKM's valuation of depreciated replacement cost to replacement cost as calculated in 1994). The accumulative rate of depreciation for the opening WDV is then calculated for each year from 1994 and is used to determine the depreciation on the opening WDV for each progressive year.

The second step is to determine the accumulative rate of depreciation for new assets installed since 1994. This is based on the standard asset life for each asset installed consistent with asset category in which the capex is spent and the years since the expenditure.

15 CitiPower, response asset modelling questions, email to AER staff, 8 Feb 2010.

The third step is to determine the total depreciation. Accordingly, the total depreciation on the opening WDV and the total depreciation on new capex for each year since 1994 is summed for each asset category.

Finally, the remaining life for each asset category is calculated by dividing the opening 2011 asset value by the average depreciation forecast for the period 2011–2015 for the asset category.

The AER considers this approach to be reasonable and results in a depreciation profile that is in accordance with clause 6.5.5(b)(1) of the NER.

The calculation of the remaining life for distribution system assets and non-network general is dependent on the standard life. Accordingly, the AER has recalculated the remaining life for distribution system assets and non-network general assets to reflect standard asset lives of 49 years for distribution system assets and 10 years for non-network general assets. The AER has adopted these asset lives and made further adjustments to CitiPower's remaining lives as a result of changes to its roll forward calculations. After making these changes, the AER has determined CitiPower's asset lives as set out in table 10.7.

Table 10.7 AER conclusion on asset lives for CitiPower (years)

Asset category	2011–15 standard lives for new capex	2011–15 remaining asset lives
Subtransmission	50.0	22.1
Distribution system assets	49.0	21.6
Standard metering	N/A	6.1
Public lighting	N/A	13.3
SCADA/Network control	13.0	7.7
Non-network general assets—IT	6.0	5.2
Non-network general assets—other	10.0	6.6
Equity raising costs	46.6	–

Powercor regulatory proposal

Powercor proposes the same standard asset lives for new capex as apply in the current regulatory control period, with the addition of a new asset category for equity raising costs.

Table 10.8 Powercor proposed standard and remaining asset lives (years)

Asset category	2006–10 standard asset lives for new capex	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	50.0	50.0	25.8
Distribution system assets	51.0	51.0	25.5
Standard metering	N/A	N/A	5.8
Public lighting	N/A	N/A	14.1
SCADA/Network control	13.0	13.0	6.4
Non-network general assets—IT	6.0	6.0	5.2
Non-network general assets—other	15.0	15.0	9.7
Equity raising costs	–	46.2	–

Source: Powercor roll forward model and PTRM.

AER considerations—Powercor's standard lives

The AER has adopted the standard asset lives proposed by Powercor as they are consistent with those adopted for the current regulatory control period and with technical lives for assets in each of these categories.

The AER considers that Powercor's proposed standard lives reflect the nature of those asset categories over their economic lives in accordance with clause 6.5.5(b)(1) of the NER.

AER considerations—Powercor's remaining lives

As discussed for CitiPower, Powercor has calculated its remaining asset lives for its existing assets using the same depreciation methodology as CitiPower.

For Powercor the remaining life for the WDV of the assets as at 1994 is determined by multiplying the standard asset lives for each asset category by an average remaining life of 55.3 per cent, which is the 1994 ratio of SKM's valuation of Powercor's depreciated replacement cost to replacement cost as advised by SKM. The accumulative rate of depreciation for the opening WDV is calculated for each year from 1994 and is used to determine the depreciation on the opening WDV for each progressive year.

The accumulative rate of depreciation for new assets installed from 1994 is then determined based on the standard asset life for each asset installed consistent with asset category in which the capex is spent and the years since the expenditure.

The total depreciation (including depreciation on the opening WDV and depreciation on new capex for each year since 1994) is then summed for each asset category. The remaining life for each asset category is calculated by dividing the opening 2011 asset value by the average depreciation forecast for the period 2011–15 for the asset category.

The AER considers this approach to be reasonable and in accordance with clause 6.5.5(b)(1) of the NER.

The AER has made corrections to Powercor's remaining lives for its assets arising from changes made to its roll forward calculations. After making these changes Powercor's asset lives are set out in table 10.9.

Table 10.9 AER conclusion on asset lives for Powercor (years)

Asset category	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	50.0	25.8
Distribution system assets	51.0	25.7
Standard metering	N/A	5.8
Public lighting	N/A	13.1
SCADA/Network control	13.0	6.3
Non-network general assets—IT	6.0	5.2
Non-network general assets—other	15.0	9.7
Equity raising costs	45.2	N/A

SP AusNet regulatory proposal

SP AusNet's proposed asset lives are set out in table 10.10. SP AusNet proposed different standard asset lives for new capex for the forthcoming regulatory control period compared to the current regulatory control period.

Table 10.10 SP AusNet proposed standard and remaining asset lives (years)

Asset category	2006–10 standard asset lives for new capex	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	33.0	45.0	29.2
Distribution system assets	33.0	50.0	29.1
Standard metering	N/A	N/A	0.0
Public lighting	N/A	N/A	0.0
SCADA/Network control	5.0	5.0	0.0
Non-network general assets—IT	5.0	5.0	3.8
Non-network general assets—other	1.0	1.0	0.5

Source: SP AusNet roll forward model and PTRM.

AER considerations—SP AusNet's standard lives

For the current regulatory control period, SP AusNet proposed a stable rolling weighted average asset life for its assets. This methodology holds constant the percentage of the RAB asset category being depreciated each year. One consequence of this is that the sunk and new assets in an asset category have the same life. The rationale for this approach was that the capex proposed broadly matched the depreciation and retirement of existing assets such that the average remaining life remained relatively stable. For the forthcoming regulatory control period, SP AusNet comments that it does not consider the above approach compliant with the NER. As such SP AusNet has proposed standard lives for new assets added post 2010 that meet the requirements of the NER. The AER considers SP AusNet's proposed asset lives for new capex for subtransmission and distribution system assets is more consistent with the technical lives for these assets and are comparable to the asset lives proposed by the other DNSPs. The AER accepts SP AusNet's proposed standard asset lives for new capex for subtransmission and distribution system assets.

The AER considers that SP AusNet's proposed standard life for 'non general assets-other' of one year is inconsistent with the proposed standard lives of the other Victorian DNSPs which range from 7.5 years to 18.9 years. In considering the proposed standard life for this asset category, the AER noted that while SP AusNet's proposed standard life is consistent with that of the current regulatory control period, the actual capex incurred for this asset category of $32 million ($, 2010) is considerably higher than the forecast of $1.7 million ($, 2010) at the time of the 2006–10 review. The AER also notes that SP AusNet's proposed capex for this category is about $35 million. SP AusNet comments that this asset category is still dominated by assets where a one year standard life is reasonable such as tools and equipment, personal communications equipment (mobiles) and specific expenditures such as condition monitoring equipment and billing system upgrades.[16] The information provided by SP AusNet is summarised in table 10.11.

Table 10.11 SP AusNet capex for non-network general assets—other

Asset types included	Examples
General Property works (excludes property purchases)—approx. $11.25 million.	Covered areas for EWP storage; zone sub toilets; replacement office furniture; replacement bitumen in depots; portable site huts; truck washing facilities.
Communications—approx. $2 million.	Mobile phones / satellite phones; smart boards / projectors etc; specific communications upgrades at depots (eg. telephone systems)
Tools and equipment (excludes fleet)—approx. $18 million.	Replacement ladders, chainsaws, ampact tools, vehicle tools etc; new gas analysers; oil test sets, CB Analysers, CT Testers.
Specific expenditure—approx $3.75 million.	Condition monitoring; critical peak demand pricing (eg. billing system upgrades); enhanced storage facilities for spare equipment.

Source: SP AusNet, response to AER remaining life and PTRM questions, email to AER staff, 19 February 2010.

In reviewing this information the AER considers that many of the example assets listed would have expected economic lives considerably longer than one year. For example, the AER considers office furniture, zone sub toilets and portable sheds to have lives of between 10 and 20 years; office equipment and machines to have lives of 10 years and cellular mobile phones to have lives of 6 years. Based on the examples list and relative amounts of expenditure listed in each subcategory, the AER has recalculated the standard life for the 'non general assets - other' category in proportion to the expenditure amounts in each subcategory as outlined in table 10.12. The AER considers that a life of approximately 5 years reflects the expected economic life of these assets and results in a depreciation schedule that is in accordance with clause 6.5.5(b)(1) of the NER.

[16] SP AusNet, response to AER remaining life and PTRM questions, email to AER staff, 19 February 2010.

Table 10.12 AER conclusion on standard life for non-network general assets—other

Asset sub category	Expected life (years)	Capex ($'m)	Weighted average life (years)
General property works (excludes property purchases)	10	11.3	3.2
Communications	6	2.0	0.3
Tools and equipment (excludes fleet)	2	18.0	1.0
Specific expenditure	2	3.8	0.2
Total		**35.0**	**4.8**

Note: Totals may not add due to rounding.

AER considerations—SP AusNet's remaining lives

To calculate the remaining lives for its RAB as at 1 January 2011 SP AusNet has calculated a weighted average asset life based on the opening RAB in 2006 and new capex spent during the period. The remaining lives specified in the ESCV's 2006 determination are adjusted for the elapsed time since 1 January 2006. The weighted average life for the RAB as at 1 January 2011 is determined by multiplying the proportion of depreciation of the RAB for each year 2006–2010 by the remaining asset life at each year 2006–2010.

The AER considers this approach to be reasonable and in accordance with clause 6.5.5(b)(1) of the NER.

The AER has made the following corrections to SP AusNet's asset lives. These changes also allow for consistency with AER changes to the roll forward model. After making these changes, the AER has determined SP AusNet's asset lives as set out in table 10.13.

Table 10.13 AER conclusion on asset lives for SP AusNet (years)

Asset category	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	45.0	29.5
Distribution system assets	50.0	29.1
Standard metering	N/A	1.0
Public lighting	N/A	N/A
SCADA/Network control	5.0	N/A
Non-network general assets—IT	5.0	3.6
Non-network general assets—other	5.0	1.0

United Energy regulatory proposal

United Energy's proposed asset lives are set out in table 10.14.

Table 10.14 United Energy proposed standard and remaining asset lives (years)

Asset category	2006–10 standard asset lives for new capex	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	60.0	60.0	24.0
Distribution system assets	35.6	35.6	24.0
Standard metering	N/A	N/A	5.0
Public lighting	N/A	N/A	5.0
SCADA/Network control	5.0	5.0	1.0
Non-network general assets—IT	5.0	5.0	5.0
Non-network general assets—other	7.5	7.5	5.0

Source: United Energy roll forward model and PTRM.

AER considerations—United Energy's standard lives

In its regulatory proposal, United Energy listed a standard life of 10 years for 'non-network general assets - other' compared to 7.5 years entered in its PTRM. United Energy confirmed that 7.5 years is the correct value for other assets.[17] United Energy

[17] United Energy, response to AER asset modelling questions, email to AER staff, 19 February 2010.

proposes the same standard asset lives for new capex as apply in the current regulatory control period.

AER considerations—United Energy's remaining lives

United Energy's remaining life model calculates the remaining life for its sub transmission and distribution assets only. To calculate the remaining lives for these assets United Energy first identifies the age of every asset type for each year from 1910. (These calculations are made by multiplying the volume of assets at each age by the relevant unit replacement cost for the asset type and then dividing by the unit replacement cost and volume of assets).

United Energy then calculates the average remaining life for each of its assets, this is done by calculating the difference between the standard life and the age of the asset at each year and then calculating an average remaining life (The volume of assets in each year is multiplied by the remaining life and multiplied by the unit replacement cost. It is then divided by volume of assets multiplied by the unit replacement cost). The assets are then grouped into the following categories: All SubTransmission Assets; All HV Urban Assets; All HV Rural Assets; All LV Urban Assets and All LV Rural Assets and average remaining lives are calculated for each asset group.

The AER has reviewed United Energy's remaining life model and based on the model has calculated average remaining lives for the subtransmission category of 22.5 years and for the distribution system asset category of 25 years. The AER considers United Energy's proposed remaining lives of 24 years for these two asset categories to be consistent with its remaining life model.

United Energy did not provide the calculations for the remaining lives for its other asset categories. However the AER notes that the remaining lives for these other asset categories (including standard metering, public lighting, SCADA/Network control, Non-network general assets—IT and Non-network general assets—other) are consistent with those used for the current regulatory control period, and that such consistency is reasonable and expected given relative proportions of capex and depreciation of these assets.

The AER considers United Energy's calculation of remaining lives to be in accordance with clause 6.5.5(b)(1) of the NER.

The AER has made the following corrections to United Energy's asset lives. These changes also allow for consistency with AER changes to the roll forward model. After making these changes United Energy's asset lives are set out in table 10.15.

Table 10.15 AER conclusion on remaining asset lives for United Energy (years)

Asset category	2006–10 standard asset lives for new capex	2011–15 standard asset lives for new capex	2011–15 remaining asset lives
Subtransmission	60.0	60.0	24.0
Distribution system assets	35.6	35.6	24.0
Standard metering	N/A	N/A	5.0
Public lighting	N/A	N/A	5.0
SCADA/Network control	5.0	5.0	N/A
Non-network general assets—IT	5.0	5.0	N/A
Non-network general assets—other	7.5	7.5	5.0

10.6 AER conclusion

The AER has assessed each of the Victorian DNSPs' proposed asset life inputs to the PTRM that are used to calculate regulatory depreciation in accordance with clause 6.5.5 of the NER. As a result of the required adjustments to the asset lives by CitiPower, Powercor, SP AusNet and United Energy, the AER considers that the depreciation schedules proposed by these DNSPs do not comply with the NER requirements and therefore has not approved the schedules under clause 6.12.1(8). The AER's decision on the opening RAB and depreciation can also be found in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined the Victorian DNSPs' regulatory depreciation allowances for the forthcoming regulatory control period in accordance with clause 6.5.5(a)(2)(ii), as set out in table 10.16.

While the AER has made some changes to the asset lives proposed by each DNSP, these asset lives still significantly differ across DNSPs. As discussed above, the differences apparent in the Victorian DNSPs' calculations reflect inconsistencies in asset categorisation and a general departure from the notion of an underlying 'physical' asset base and associated values. In the future the AER will consider different approaches to grouping assets in the context of the requirements of clause 6.5.5(b) which imply the recognition of individual assets or categories of assets.

Table 10.16 AER conclusion on regulatory depreciation ($'m, nominal)

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

11 Cost of capital

11.1 Introduction

This chapter sets out the AER's calculation of the rate of return for the Victorian distribution network service providers (DNSPs) for the forthcoming 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),[1] 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 it is not compensated for through the cost of capital. 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 National Electricity Rules (NER). This clause provides that the return on capital building block must be calculated by applying the rate of return to the value of the regulatory asset base (RAB) as determined in accordance with clause 6.5.1 and schedule 6.2 of the NER.

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:

[1] AER, *Statement of regulatory intent on the revised WACC parameters (distribution)*, 1 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).[2] 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 6.5.3 of the NER:[3]

- 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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2 AER, *Electricity transmission and distribution network service providers—Review of the weighted average cost of capital (WACC) parameters*, Final decision, 1 May 2009.

3 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.[4] Under clause 6.5.4(g) of the NER, a distribution determination must be consistent with the relevant SORI unless there is persuasive evidence justifying a departure from a value, method or credit rating level set out in the SORI. Clause 6.5.4(h) of the NER requires that in deciding whether a departure from a value, method or credit rating level set in the SORI is justified, the AER must consider:

> (1) the criteria on which the value, method or credit rating level was set in a SORI (the underlying criteria); and
>
> (2) whether, in light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in a statement inappropriate.

The AER considers the underlying criteria of the SORI refer to sections and/or rules under the NER and the National Electricity Law (NEL), to which the AER relied upon to determine each particular value, method or credit rating level. While the actual criteria used are discussed below in relation to each WACC parameter, the AER also applied other general criteria set out in clause 6.5.4(e) of the NER, including:

> (1) the need for the rate of return calculated for the purposes of clause 6.5.2(b) to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services; and
>
> (2) the need for the return on debt to reflect the current cost of borrowings for comparable debt; and
>
> (3) the need for the credit rating levels or the values attributable to, or the methods of calculating, the parameters referred to in paragraph (d) that vary according to the efficiency of the Distribution Network Service Provider to be based on a benchmark efficient Distribution Network Service Provider; and
>
> (4) where the credit rating levels or the values attributable to, or the method of calculating, parameters referred to in paragraph (d) cannot be determined with certainty:
>
> > (i) the need to achieve an outcome that is consistent with the national electricity objective; and
> >
> > (ii) the need for persuasive evidence before adopting a credit rating level or a value for, or a method of calculating, that parameter that differs from the credit rating level, value or the method of calculation that has previously been adopted for it.

The National Electricity Objective (NEO) is defined in the NEL as:

[4] AER, *Statement of regulatory intent*, 1 May 2009.

> 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.[5]

As a fundamental part of the WACC review, the AER also consulted on the meaning of the term ‘persuasive evidence’, concluding that:

> … 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.[6]

The AER then applied this definition 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, 1 May 2009.

The AER determined in the SORI that the nominal risk-free rate is to be calculated:

- on a moving average basis of the annualised yield on Commonwealth government securities (CGS)
- using a maturity of 10 years
- with the agreed averaging period being one which is as close as practically possible to the commencement of the regulatory control period

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5 NEL, Part 1, section 7.

6 AER, *Statement of regulatory intent*, 1 May 2009.

- 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 Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs have proposed a nominal WACC of 10.86 per cent, based on an indicative averaging period.[7] The parameters proposed by each of the Victorian DNSPs are shown in table 11.2. The proposed methods, values, parameters and credit ratings are consistent with the AER's SORI with the exception of the MRP.

Table 11.2 Proposed WACC parameters

Parameter	CitiPower	Powercor	Jemena	SP AusNet	United Energy	SORI
Gearing level (debt/equity)	0.60	0.60	0.60	0.60	0.60	0.60
Nominal risk-free rate	10 year CGS	10 year CGS	10 year CGS	10 year CGS	10 year CGS	10 year CGS
Market risk premium	8%	8%	8%	8%	8%	6.5%
Equity beta	0.80	0.80	0.80	0.80	0.80	0.80
Credit rating level	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
Debt risk premium	[4.71%]	[4.71%]	[4.71%]	[4.71%]	[4.71%]	–
Expected inflation rate	[2.44]	[2.44]	[2.47]	[2.40]	[2.44]	–
Nominal WACC	[10.86%]	[10.86%]	[10.86%]	[10.86%]	[10.86%]	–

Note: Numbers in brackets are indicative 'place holders' only.
Source: CitiPower, *Regulatory proposal*, pp. 307–308; Powercor, *Regulatory proposal*, pp. 315–316; Jemena, *Regulatory proposal*, pp. 163–164; SP AusNet, *Regulatory proposal*, pp. 295 and 303; and United Energy, *Regulatory proposal*, pp. xxiv and 138.

The AER notes the Victorian DNSPs have adopted the methodology for forecasting inflation—as described in the final decision for the New South Wales and Australian Capital Territory distribution determinations.[8] However, the AER observes that only Jemena Electricity Networks (Jemena) has calculated the inflation forecast figure correctly (see section 11.5.7). The AER also notes that the Victorian DNSPs

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[7] CitiPower, *Regulatory proposal 2011 to 2015,*, 30 November 2009, p. 308; Jemena, *Regulatory proposal 2011-2015*, 30 November 2009, p. 163; Powercor, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 316; SP AusNet, *Electricity Distribution Price Review, Regulatory proposal,* 30 November 2009, p. 303; and United Energy, *Regulatory proposal for distribution prices and services,*, November 2009, p. 138.

[8] CitiPower, *Regulatory proposal,* 30 November 2009, p. 307; Jemena, *Regulatory proposal,* 30 November 2009, p. 164; Powercor, *Regulatory proposal,* 30 November 2009, p. 315; SP AusNet, *Regulatory proposal*, 30 November 2009, p. 295; and United Energy, *Regulatory proposal,* 30 November 2009, p. xxiv.

have not adopted the AER's methodology for estimating the return on debt—as described in the final decision for the New South Wales and Australian Capital Territory distribution determinations (see section 11.5.6).[9]

11.4 Summary of submissions

The AER received submissions on the WACC from the Energy Users Coalition of Victoria (EUCV), the Consumer Action Law Centre (CALC) and TRUenergy.

The EUCV commented on the regulatory framework and noted:

- the AER must take significant cognisance of its recent determination on WACC, which was released in May of 2009.[10]
- that the AER recognise that its WACC review is still current and the inputs should remain as determined in that review. There is a strong view that regulatory certainty should be an overriding concern.[11]
- if the AER considers there is persuasive evidence to vary some WACC parameters (since the WACC review), there is a strong argument to re-evaluate other WACC input elements.[12]

The EUCV also highlighted that (as noted previously by the MEU) generally the AER took a conservative view on each parameter and if it had used the mid point in setting for each, it would have provided an outcome which would have resulted in a lower overall WACC.[13]

In relation to the MRP, the EUCV[14] and the CALC[15] noted that various financial market indicators suggest that an 8 per cent MRP is unjustified, and an MRP estimate should not exceed 6.5 per cent. TRUenergy considered that the MRP should return to its traditional historical value of 6 per cent.[16]

11.5 Issues and AER considerations

Regarding the comments made by the EUCV on the overall WACC and regulatory framework, the AER notes that it must comply with the SORI when making distribution determinations under clause 6.5.4(g) of the NER, and can only depart from the SORI in light of a material change in circumstance since the date of the

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9 CitiPower, *Regulatory proposal*, p. 299; Jemena; *Regulatory proposal*, p. 173; Powercor, *Regulatory proposal*, p. 307; SP AusNet, *Regulatory proposal*, pp. 296–297; and United Energy, *Regulatory proposal*, pp. 147–148.

10 Energy Users Coalition of Victoria, *Applications from CitiPower, Jemena, Powercor, SP AusNet and United Energy: A response*, February 2010, p. 7.

11 ibid., p. 69.

12 ibid.

13 ibid., p. 74.

14 ibid., pp. 69–70.

15 Orion Economic Services for the Consumer Action Law Centre, *Review of the initial Victorian distribution network service providers proposals for the 2011–2015 regulatory period*, February 2010, pp. 34–38.

16 TRUenergy, *Submissions on the Victorian electricity distribution network service providers' regulatory proposals*, p. 3.

statement or any other relevant factor. For this reason the parameters set in the SORI (whether regarded as conservative or otherwise) and the AER's recent WACC review clearly remains relevant.

Further issues with respect to each WACC parameter are discussed in the following sections.

11.5.1 Gearing

Gearing is defined as the ratio of the value of debt to total capital (both debt and equity), and is used to weight the costs of debt and equity when formulating a WACC. A business's gearing, also referred to as its capital structure, will have a significant bearing on the expected required return on debt and the expected required return on equity (although notionally, it is unlikely to affect the cost of capital). The SORI specifies gearing ratio is 0.60.[17]

Regulatory requirements

The underlying criteria used by the AER in its SORI in relation to gearing are:

- 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.[18]

DNSPs regulatory proposals

The Victorian DNSPs applied the parameter values specified in the SORI for the proportion of debt funding in their respective regulatory proposals.[19]

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[17] AER, *Statement of regulatory intent*, 1 May 2009.
[18] NER, cl. 6.5.4(e); NEL, Part 1, section 7A.
[19] CitiPower, *Regulatory proposal*, 30 November 2009, p. 298; Jemena, *Regulatory proposal*, 30 November 2009, p. 164; Powercor, *Regulatory proposal*, 30 November 2009, p. 306; SP AusNet,

Issues and AER considerations

The gearing ratio of 60 per cent proposed by the Victorian DNSPs is as specified in the SORI and consistent with the NER, and is accordingly considered appropriate by the AER.

In accordance with the underlying criteria, the AER considers the proposed level of gearing:

- is supported by the most recent available and reliable empirical evidence, which the AER considers does not support a change to the existing value in the SORI

- generates a forward looking rate of return that is commensurate with prevailing conditions in the market for funds

- together with values, methods and a credit rating for the other parameters, provides a service provider with a reasonable opportunity to recover at least the efficient costs and provides a service provider with effective incentives for efficient investment

- is appropriate having regard to the economic costs and risks of the potential framework in under and over investment.

On this basis, the AER considers the Victorian DNSPs' proposed value achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[20]

AER conclusion

The gearing ratio of 60 per cent proposed by the Victorian DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

11.5.2 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 proposal, 30 November 2009, p. 286; and United Energy, *Regulatory proposal*, 30 November 2009, p. 146.

20 NER, cl. 6.5.4(e).

Regulatory requirements

The SORI states that the methodology for estimating the risk-free rate is based upon the yield on CGS with a maturity of 10 years, calculated over a 10 to 40 business day period commencing as close as practically possible to the start of the regulatory control period.

Prior to the SORI, the AER determined a risk-free rate that is observed as close as practically possible to the date of the final decision. The averaging period was agreed upon between the AER and the network service provider. The AER notes that it is implicit in the NER that the averaging period for the DRP uses the same period, as the DRP is based upon the difference between the observed cost of debt and the nominal risk-free rate.[21]

The underlying criteria used by the AER in the WACC review relating to the nominal risk-free rate are:

- the need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services
- 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.[22]

DNSPs regulatory proposals

Most of the Victorian DNSPs have proposed to adopt the method specified in the SORI for the nominal risk-free rate.[23] The AER observes that one DNSP has proposed an averaging period which is not consistent with the SORI.

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[21] NER, cll. 6.5.2(b) and 6.5.2(e).

[22] NER, cl. 6.5.4(e); and NEL, Part 1, section 7A.

[23] The AER notes that the DNSPs have chosen to keep the averaging period confidential and note the number of days of the averaging period for each of the businesses is within the 10 to 40 day average. CitiPower, *Regulatory proposal*, p. 297; Jemena, *Regulatory* CitiPower, *Regulatory*

Issues and AER considerations

The method proposed to estimate the nominal risk-free rate by most of the Victorian DNSPs (which includes the proposed averaging period) is as specified in the SORI and is accordingly accepted by the AER. The AER observes that one DNSP has proposed an averaging period which is not consistent with the SORI.

However, on 12 November 2009, the Australian Competition Tribunal made a ruling with respect to the circumstances under which the AER could withhold agreement to a proposed averaging period. The AER notes the Tribunal's decision may be relevant for consideration under clause 6.5.4(g) of whether there is persuasive evidence for departing from the SORI in this particular case.

The Tribunal stated that there appeared to be no virtue in setting the risk-free rates and corporate bond rates at values which prevailed close to the start of the regulatory control period or to the publication of a final determination.[24] Further, any rejection by and claims of overcompensation by the AER, with respect to the selection of the averaging period, should have been supported by an accompanying yield curve analysis to derive future 10 year CGS yields.[25] This reasoning is based upon the pure expectations hypothesis. The pure expectations hypothesis considers that forward rates can be estimated from a simple average of earlier maturing securities. Short term yields (currently known) can be used to estimate forward rates, which are used as an approximate of yields for longer-dated securities that are expected to prevail in the future. This assumes a simple relationship between long and short term yields and proposes that long term yields do not suffer from any bias as that investors are indifferent between holding a long term investment for a set period and reinvesting in short term securities over the same period. For example, under this theory, an investor would be indifferent between investing once in a 10 year CGS, and by investing in a 1-year CGS 10 times over 10 years.

However, it has been demonstrated empirically that the assumption that an investor is indifferent between holding fixed income securities with different maturities is not realistic.[26] This arises due to the presence of uncertainty about the future and securities having different features (for example, zero coupon compared to coupon paying bonds).[27]

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proposal, p. 162; Powercor, *Regulatory proposal*, p. 305; SP AusNet, *Regulatory proposal*, p. 294; and United Energy, *Regulatory proposal*, p. 139.

24 Australian Competition Tribunal, Application by Energy Australia and Others (No 2) [2009] ACompT 8, 12 November 2009, p. 90.

25 Australian Competition Tribunal, Application by Energy Australia and Others (No 2) [2009] ACompT 8, 12 November 2009, pp. 94–101.

26 For example see Finlay, R. and Chambers, M., 'A term structure decomposition of the Australian yield curve', *Economic Record*, Vol. 85, No. 271, December 2009, pp. 38–40; and Kim, D. H. and Wright, J. H., 'An arbitrage-free three-factor term structure model and the recent behaviour of long term yields and distant-horizon forward rates', Federal Reserve Board of Finance discussion series No. 2005-48.

27 Another factor discussed in the academic literature that may affects observed yield curves is the market segmentation theory. This relates to bonds having different features that different groups of investors may value differently. An example of this would be superannuation funds having a preference for index-linked bonds.

The AER is still examining the full implications of the Tribunal's decision and its relationship to the requirements of the SORI as well as to the broader NER framework relating to the derivation of the WACC parameters. There are a number of issues that need to be resolved to enable the AER to properly proceed and consider proposals by DNSPs to depart from the SORI in relation to their averaging periods (and potentially the term of the risk-free rate).

That said, given the uncertainties of the operation of the SORI/NER framework in light of the Tribunal's decision, the AER accepts the Tribunal's decision as a relevant factor justifying a departure from the SORI in the current circumstances. Therefore, for the Victorian distribution determination process, the AER has accepted the Victorian DNSPs' averaging periods.

AER conclusion

The AER has accepted four of the Victorian DNSPs' proposed averaging periods as they are in accordance with the SORI. For the other DNSP, the AER accepts the Tribunal's decision as a relevant factor justifying a departure from the SORI in the current circumstances and has therefore accepted its proposed averaging period also.

For this draft decision, the 15-day moving average for CGS yields with a 10 year maturity for the period ending 19 March 2010 results in a proxy nominal risk-free rate of 5.65 per cent (effective annual compounding rate). The AER will update the risk-free rate, based on the Victorian DNSPs' 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 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.[28]

The AER considers the underlying criteria relating to the NER requirements that are of particular relevance to determine the MRP are:

- the need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services

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28 AER, *Statement of regulatory intent*, 1 May 2009, p. 7.

- 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.[29]

The AER considers the revenue and pricing principles that are of particular relevance to the method used to estimate the MRP 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.[30]

DNSPs regulatory proposals

The Victorian DNSPs proposed a MRP of 8 per cent.[31] This represents a departure from the 6.5 per cent MRP specified in the SORI. The Victorian DNSPs' proposals are based upon advice provided by Dr Steven Bishop and Professor Bob Officer on behalf of Value Advisor Associates.

Officer and Bishop examined the underlying basis and reasoning that the AER applied to support its determination of a 6.5 per cent MRP in the SORI. Officer and Bishop:

- noted that they have been asked to recommend a MRP that is expected to prevail over the period 2011–15
- advocated under 'normal' market conditions the use of a long term historical average of excess returns[32]
- did not consider conditions for 2011–15 are representative of 'normal' conditions and therefore the MRP expected to prevail over this period is well above 6.5 per cent
- proposed a 7 per cent estimate for the long term equilibrium MRP instead of the AER's 6 per cent estimate and also anticipate a forward looking MRP of 12 per cent
- formed a view based upon forward looking MRPs and the long term equilibrium MRP, that a MRP of 8 per cent should apply to DNSPs over the regulatory control period.[33]

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29 NER, cl. 6.5.4(e).

30 NEL, Part 1, section 7A.

31 Powercor, *Regulatory proposal*, p. 312; Citipower, *Regulatory proposal*, p.304; United Energy, *Regulatory proposal*, p.146; SP AusNet, *Regulatory proposal*, p. 295; and Jemena, *Regulatory proposal*, p. 172

32 The AER notes Officer and Bishop refer to this as the long term historical MRP.

The Victorian DNSPs also raised concerns about the current volatile state of the economy and assert that this has increased the cost to raise equity capital on financial markets. Various market commentators' opinions were cited to support this notion.

Submissions

The CALC noted that falling credit spreads between corporate bonds and CGS and declining LIBOR rates, suggests a falling cost of debt. CALC considered that given the interrelation of debt and equity markets, the MRP has also more than likely fallen.[34]

The EUCV considered that the mass stimulus packages undertaken by governments world-wide will require financing through a large issuance of government bonds. This is expected to reduce bond prices and therefore raise the yields of government debt. This will raise the risk-free rate and therefore reduce the MRP. The EUCV therefore recommend that an 8 per cent MRP is unjustified in light of these market circumstances.[35]

TRUenergy submitted that the unstable financial conditions at the time the MRP value of 6.5 per cent was set in the SORI do not currently exist:

> …the AER made it clear that prior to the on-set of the global financial crisis, an estimate of 6% was the best estimate of a forward looking long term MRP, and, accordingly, under relatively stable market conditions—assuming no structural break had occurred in the market—this would remain the AER's view as to the best estimate of the forward looking MRP.[36]

It therefore suggested that the MRP should return to its traditional historical value of 6 per cent.[37]

Issues and AER considerations

The AER has considered many of the same arguments and analysis presented by the Victorian DNSPs in its recent determinations for the Queensland and South Australian DNSPs. In these determinations the AER did not consider the implied volatility and glide path analysis presented by Officer and Bishop to be persuasive, and in any case was inconsistent with estimating the MRP over a 10 year period (being the investment term set for the risk-free rate in the SORI).

In their initial regulatory proposals, ETSA proposed an 8 per cent MRP for the 2010-15 regulatory control period[38] while Energex proposed a convenience yield of 79 basis points (to increase its proposed return on equity).[39] In their revised regulatory proposals submitted in January 2010, ETSA and Energex have noted that financial

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33 R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p.17.

34 Orion Economic Services for the Consumer Action Law Centre, *Review of the initial Victorian distribution network service providers proposals for the 2011–2015 regulatory period*, February 2010, pp. 37–38.

35 Energy Users Coalition of Victoria, *Submission to the AER*, pp. 70–71.

36 TRUenergy, *Submission to the AER*, p. 3.

37 ibid., p. 3.

38 ETSA Utilities, *Regulatory proposal 2010-2015*, 1 July 2009, p.240.

39 Energex, *Regulatory proposal for the period July 2010 – June 2015*, July 2009, p. 238.

conditions have changed since the submission of their original regulatory proposals and proposed values and methods as stated in the SORI (a 6.5 per cent MRP and no convenience yield).[40] The AER observes there is considerable overlap between Victorian, South Australian and Queensland regulatory control periods, and consider a similar cost of equity is likely to apply across both periods. As such, ETSA and Energex's proposals further support that a MRP of 6.5 per cent is appropriate over the regulatory control period 2011–15.

The remainder of this section addresses the issues raised in relation to:

- commentary on market conditions
- forecast dividend yields
- Officer and Bishop's proposed estimation of a "forward looking" MRP using implied volatilities and a glide path that reverts to a long term historical average of the MRP
- Officer and Bishop's estimation of a forward looking MRP in light of corporate debt spreads.

Commentary on market conditions

In their proposals, the Victorian DNSPs claimed that the continued negative effects of the global financial crisis (GFC) and the consequent increased volatility on financial markets have raised the returns required by equity holders. Furthermore, the negative economic conditions are expected to persist over the duration of the regulatory control period, and raise the cost of equity capital at that time.

The Victorian DNSPs argued that the forward looking MRP and the cost of equity is still relatively high compared to pre-GFC levels. Their sentiment is encapsulated by CitiPower and Powercor comments:

> It would be premature to suggest with any confidence that a turnaround has occurred and that the market cost of equity has returned to levels that preceded the GFC.[41]

The Victorian DNSPs cited the RBA's statement of monetary policy, August 2009 to support their notion:

> …my theme today is one of cautious optimism about the global situation. We can't yet say that things are back to normal, and we still can't rule out further setbacks…the extreme risk aversion of late last year has been easing for some months now, and the banks' access to wholesale funding markets has been improving. It's important to keep this in perspective: these market indicators

40 ETSA Utilities, *Revised regulatory proposal 2010-2015*, p. 197; Ergon Energy, *Revised regulatory proposal 2010-2015*, p. 185; and Energex, *Revised regulatory proposal*, p. 37.

41 CitiPower, *Regulatory proposal*, p. 301.

> are still, in some cases, a long way from pre-crisis levels, particularly for borrowing costs at longer maturities.[42]

In a similar vein, the Victorian DNSPs also cited comments from Nouriel Roubini (Professor of economics at New York University's Stern School of Business):

> In summary, the recovery is likely to be anaemic and below trend in advanced economies and there is a big risk of a double-dip recession.[43].

The AER notes that its decision to increase the MRP from the previously adopted value of 6 per cent to 6.5 per cent in the SORI reflected market conditions at the height of the GFC.[44] The comments made and presented by the Victorian DNSPs indicate improvement from the situation at the time, lending support for a MRP below 6.5 per cent, rather than increasing it substantially to 8 per cent as proposed by the Victorian DNSPs.

Furthermore, the AER has found more optimistic comments about signs of stabilisation in both equity and debt markets. For example, the IMF recently noted in its *World Economic Outlook Update*:

> Money markets have stabilized, and the tightening of bank lending standards has moderated. Moreover, most banks in core markets are now less reliant on central bank emergency facilities and government guarantees. Nonetheless, bank lending is likely to remain sluggish, given the need to rebuild capital, the weakness of private securitization, and the possibility of further credit write-downs, notably related to commercial real estate.
>
> Equity markets have rebounded, and corporate bond issuance has reached record levels, amid a reopening of most high-yield markets. However, the surge in corporate bond issuance has not offset the reduction in bank credit growth to the private sector. Those sectors that have only limited access to capital markets, namely consumers and small and medium-size enterprises are likely to continue to face credit constraints. So far, public lending programs and guarantees have been critical in channelling credit to these sectors.
>
> Sovereign debt has come under pressure for some small countries, as they struggle with large government deficits and debt, and as investors increasingly differentiate across countries.[45]

The performance of the equity market was acknowledged in the RBA's February 2010 Statement of Monetary Policy:

> Over 2009, the ASX 200 increased by 31 per cent, its largest gain since 1993. All sectors of the Australian share market recorded increases over the year.[46]

In addition, the RBA also identified the recent surge in equity issuance to fund investment, which suggests improved confidence in the business sector:

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42 Edey, M. 'The evolving financial situation', speech delivered at the Finsia Financial Services Conference, 28 October 2009.

43 http://www.ft.com/cms/s/0/9022/fdc-900d-11de-bc59-00144feabdc0.html.

44 AER, *Final Decision Review of the Statement on the revised WACC parameters*, May 2009, p. xiv.

45 IMF, *World Economic Outlook update*, 26 January 2010, p. 3.

46 RBA, *Statement on Monetary Policy*, 4 February 2010, p. 50.

> Equity raisings remain the main source of business external funding, particularly for listed corporates. Already listed corporates (ie. excluding IPOs) issued $15 billion of new equity during the December quarter, bringing issuance to a record $70 billion for 2009. While companies are continuing issue equity with the intention of retiring debt, an increasing number of companies have announced equity raisings to fund investment, including acquisitions.[47]

These comments reflect the sentiments expressed by CALC and the EUCV that markets have shown signs of improvement, including in response to government stimulus packages. The AER also acknowledges TRUenergy's view that market conditions have now stabilised to an extent that would justify the AER determining that a value of 6 per cent was appropriate.

In this context the AER considers that the Victorian DNSPs' arguments about the forward looking MRP and cost of equity in relation to the GFC are not persuasive, and other statements from central monetary agencies indicate that a MRP of 6.5 per cent may even be generous if market conditions continue to improve. However, the AER considers that, at present, the weight of evidence does not support a MRP which is lower than the SORI value of 6.5 per cent.

Forecast dividend yields

Jemena, SP AusNet and United Energy cited research performed by the Financial Investor Group (FIG) that attempted to measure the forward looking MRP under prevailing market conditions. The research contended that forecasted dividend yields implied investors currently expect a pre-tax return on equity in the range of 15 to 18 per cent.[48] This analysis of the return on equity should be considered in light of its component parts, being the nominal risk-free rate, equity beta and MRP, rather than just the MRP in isolation.

The AER has concerns about this analysis as:

- the trading yields are based upon projected dividends (which would assume dividend growth) and it would therefore seem inappropriate to include further projections of dividend growth by other analysts

- it is not clear which time periods have been considered and methods used to estimate the yields provided by United Energy in its submission (for example, whether a dividend discount model or other approach has been used).

The AER considers dividend yields should only be used as a cross-check for the forecast return on equity, as the forecasts rely upon assumptions relating to the growth of dividends. The AER has examined the impact on the return on equity by using different MRPs (6 per cent and 8 per cent), given the Victorian DNSPs have only proposed a departure from the MRP in the SORI. Figure 11.1 provides a recent forecast of dividend yields for energy businesses.

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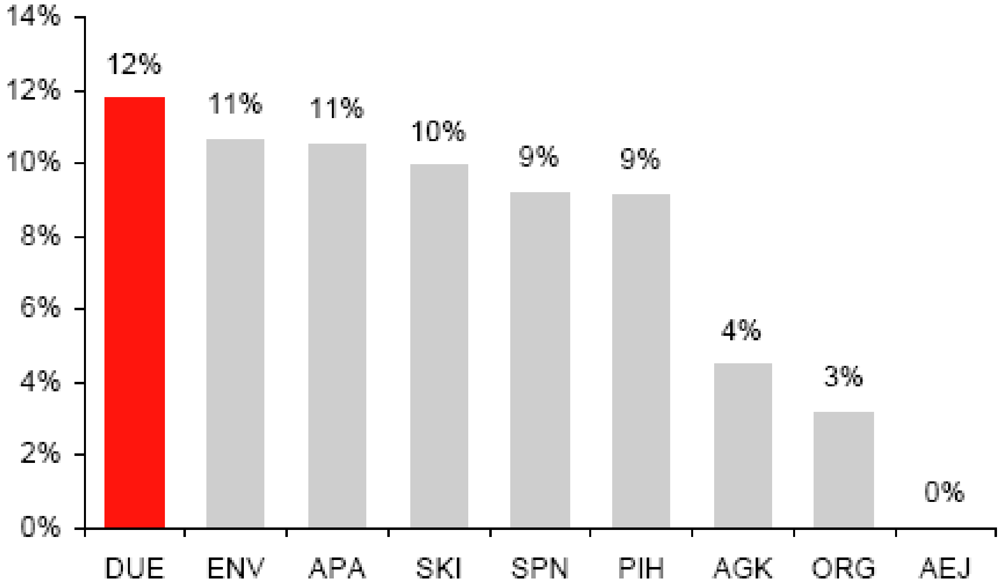
[47] ibid., p. 48.

[48] United Energy, *Regulatory proposal*, p. 143; SP AusNet, *Regulatory proposal*, p. 292; Jemena, *Regulatory proposal*, p. 169.

Figure 11.1 Regulated utilities—forecast dividend yields (2010–11)



Regulatory Commission applies rate of return regulation to businesses which incorporates costs that are applied as operating expenditure allowances under the NER (for example, equity raising costs).

Further, using the same averaging period and a MRP of 6.5 per cent would imply a return on equity of 10.85 per cent, which is above the average forecast dividend yield of 10.6 per cent.

The AER considers it is more likely that by the time of the final decision the return on equity may increase rather decrease due to the current economic environment resulting from increases in interest rates.

Overall the AER considers that the dividend yield analysis presented by the Victorian DNSPs does not constitute persuasive evidence to justify any increase in the MRP from 6.5 per cent.

Officer and Bishop glide path analysis

The Victorian DNSPs have relied upon estimates of the MRP made by Officer and Bishop, who acknowledged:

> In the past there has been insufficient theoretical basis and empirical evidence to challenge the methodology of selecting a MRP estimate based upon a long-term average of excess returns.[51]

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49 The AER considers that it would inappropriate to apply an averaging period during April 2010 to compare to yields calculated in October 2009 and has therefore used the same figures from the South Australian draft decision.

50 DUET Group, *Asset portfolio overview*, viewed 28 October 2009, www.duet.net.au/duet/asset-portfolio/index.html, The DUET Group's combined holdings of Duquesne Light and the Dampier Bunbury Pipeline equal 61.1 per cent.

51 R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p. 17.

However, Officer and Bishop argued that there is now evidence to suggest that it is appropriate to place more weight upon forward looking estimates based upon current conditions. In particular, they note an 8 per cent MRP is consistent with the current credit spreads between corporate debt and CGS, and implied volatility estimates.[52] Their implied volatility analysis (discussed in the next section) provided a range of MRPs expected to prevail over the term of the regulatory control period. Accordingly, Officer and Bishop estimate the 8 per cent forward looking MRP by:

- assuming the long term equilibrium MRP is 7 per cent
- applying a 12.2 per cent one-year forward looking estimate of the MRP based upon the relationship between the 12-month implied volatility of put options and the MRP (which is justified by work conducted by JF Capital Partners)
- taking a geometric average of the annual MRP estimates from 2011–15, with five scenarios which assume the MRP reverts to the long term equilibrium at different rates
- selecting the lowest number from the range of outcomes arising from this approach (8 to 10.6 per cent).[53]

Officer and Bishop noted:

> It is not clear how long the current high volatility and required rate of return will remain but it is apparent that the current MRP is above the long-term average....we take a conservative view of the behaviour of the implied volatility and MRP over the regulatory horizon of interest and assess the appropriate range to be between our prior recommendation of 7 and 10.6 with a recommended estimate at the lower end of the range of 8 per cent. [54]

Officer and Bishop also concluded that the 8 per cent MRP estimate is consistent with volatilities implied from 12-month ASX200 index call options and BBB-rated bond yield credit spreads.

This analysis draws on the work Officer and Bishop performed in January 2009 for the Joint Industry Association's submission on the AER's WACC review. The report advocated a 7 per cent long run historical MRP average based upon historical estimates of realised MRPs, adjusted for the impact of imputation credits.[55] It should be noted that this advice contradicts the June 2009 report by Officer and Bishop to ETSA utilities. This is acknowledged by Officer and Bishop who stated:

> This differs for our analysis for ETSA where we used the AER decision of 6.5 per cent as the long term mean. However, our recommendation was 7 per cent and we have reverted to this as we are of the view that this is more appropriate given our analysis in the Officer and Bishop Jan 2009.[56]

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52 ibid., pp. 15–16.
53 ibid., p. 1.
54 ibid., pp. 14–15.
55 Officer and Bishop, *Market Risk Premium further comments*, January 2009, p. 5.
56 Officer and Bishop, *Market Risk Premium Estimate for 2011 - 2015*, October 2009, footnote 14, p. 14.

The AER notes that Officer and Bishop, in their advice to the Victorian DNSPs, advocated the use of pre-1958 data to estimate long term historical averages of excess returns, however it is not clear how this data was incorporated into their analysis. The AER has raised concerns previously about 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.[57] Lamberton's pre-1958 data series is based on an equal weighted rather than value weighted dividend yield, which is expected to be biased towards high dividend paying small stocks. A further bias arises as the dividend yield series effectively assumes that non-dividend paying businesses had the same dividend yield as the average of dividend paying businesses.

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 126 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 pre-1958 data. In the WACC review, the AER considered numerous estimation periods (1883–2008, 1937–2008 and 1958–2008).[58]

A further issue with Officer and Bishop's glide path analysis is that it reverts to a long term MRP of 7 per cent based on an adjustment for imputation credits. On the issue of valuing imputation credits, the AER maintains its position from the WACC review:

> 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**.[59] (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 (based upon advice from Professor Davis). The AER then examined studies which did

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57 AER, *Review of the weighted average cost of capital (WACC) parameters*, Final decision, 1 May 2009, p. 195.

58 ibid., pp. 204 and 237–238.

59 ibid., p. 183.

examine the impact of gamma on long term historical averages of excess returns and noted caution should be taken with any such approach.[60]

Officer and Bishop implied volatility analysis

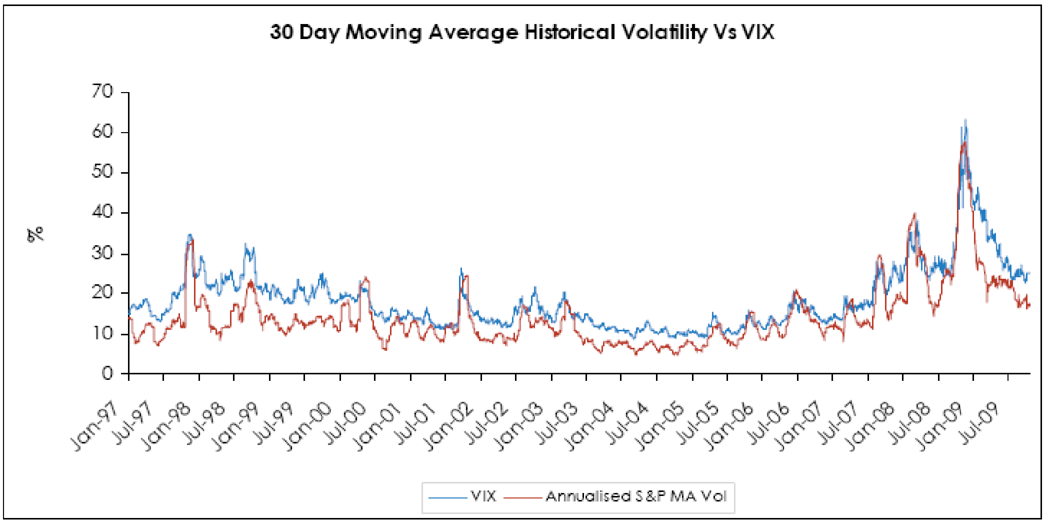
Forming part of their glide path analysis, Officer and Bishop produce a current estimate of the MRP based upon implied volatility analysis, which assumes a relationship between equity market volatility and the MRP. Officer and Bishop state the following about this relationship:

> Finance theory predicts a positive relationship between risk and return. Consequently a predictable increase in risk should be accompanied by a predictable change in return through a higher risk premium. Consistent with this relationship is an expectation that unexpected increases in risk will lead to a downward-pressure on stock prices, ceteris paribus, and therefore a negative relationship between observed returns and the unexpected changes in risk. The converse can also be expected to hold.[61]

The implied volatility is a theoretical calculation of risk that is used to compare against the volatility of the ASX200 index (measured by the standard deviation), which is used by Officer and Bishop as an actual, market-observed measure of risk. Both the implied volatility and the standard deviation are expressed in percentage terms. Officer and Bishop note the correlation of 0.89 between the implied volatility of a 30-day maturing index option and the 30-day average of the standard deviation of the ASX200 index.[62]

It is worth noting that the implied volatility is a forward looking volatility measure while the 30-day moving average is historical (backward-looking).[63] This is illustrated in Figure 11.2:

Figure 11.2 Volatility of stock market: historical versus forward view



60 ibid., pp. 207–208.

61 R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p. 8.

62 ibid., p. 7.

63 ibid.

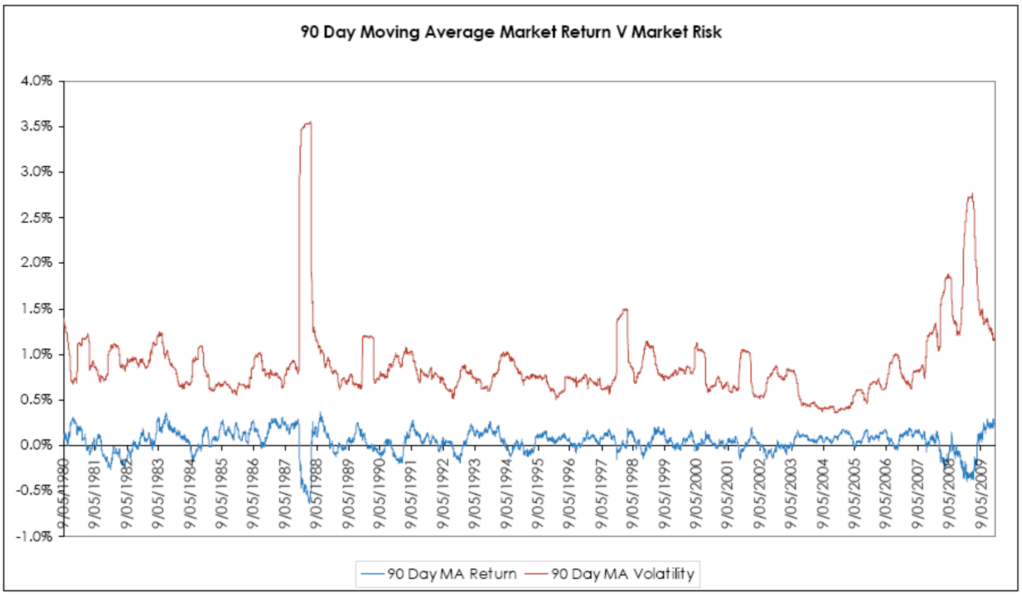
Source: Bloomberg; R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p. 8.

Officer and Bishop also note the –0.53 correlation between historical volatility estimates and the observed market returns (MRP). This result was concluded from the correlation analysis performed by Value Advisor Associates. The analysis further establishes the relationship between implied volatility and the MRP. Officer and Bishop acknowledge this and note:

> If the high correlation between the implied volatility and the 30 day moving average of historical volatility shown in Figure 4 [figure 11.2] continues, and we have no reason to believe otherwise, then the historical relationship between implied market risk and realised return can be used to extend the period of data for estimating the MRP.[64]

Officer and Bishop also attempt to establish the negative relationship between the historical volatility (measured as the standard deviation) with Figure 11.3:

Figure 11.3 Historical market return and risk



Source: Bloomberg; R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p. 9.

Officer and Bishop estimate equity market volatility, as the volatility implied from the Black-Scholes option-pricing formula, for 12-month ASX200 index call options. 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.[65] The implied volatilities method relies upon obtaining an estimate of two variables. First, the implied volatilities of stock options are 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.

64 ibid., p. 8.
65 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 3.

The 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 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.[66] 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).[67]

Using this methodology (based upon implied volatilities of ASX200 Index 12-month call options), and when combined with its glide path analysis (discussed above), Officer and Bishop found:

- that the forward looking MRP estimate to be 12.2 per cent per annum. Further, the 12.2 per cent estimate of the forward looking MRP in 2010 (in Officer and Bishop's report) is based upon a three-year glide path, starting in 2009, to 7 per cent in 2012. This reflects Officer and Bishop's assessment that the duration of the current high risk period to be no more than three years
- a forward MRP derived from current volatility is 12.2 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 7 to 10.6 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 7 per cent) is over three years
- using its preferred mean reversion path provides for a geometric average MRP of 8 per cent for 2010–15.[68]

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

66 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.

67 R. R. Officer and S. Bishop, Market risk premium–Estimate for 2011 - 2015, October 2009, Report for DNSPs, pp. 9–10.

68 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, pp. 9–11.

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.[69]

The AER has examined the analysis provided by Officer and Bishop, 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 are highly sensitive to the inputs and assumptions used. Therefore, the AER considers that the estimates derived from implied volatilities provide limited information towards an appropriate estimate of the MRP.

Officer and Bishop have also presented the implied volatilities of the ASX200 Index call option to demonstrate the MRP over 2010–15 is above 6.5 per cent. The AER has a number of observations and concerns with this approach.

First, Officer and Bishop examined the implied volatilities of the ASX200 Index call options (of 24.30 per cent) to demonstrate an estimate of a 12-month MRP is currently 12.2 per cent.[70] The AER has obtained implied volatilities of the ASX200 Index options and as shown in figure 11.4, it appears the implied volatilities of the ASX200 Index is returning back to historical levels (below 20 per cent).

Second, 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.

Third, the AER considers that the approach to estimating the implied volatility should be consistent with the calculation of other forward looking WACC estimates (such as the risk-free rate). It is unclear to the AER, whether Officer and Bishop have used an averaging period of 15 days, which would be consistent with the approach taken in the regulatory proposals.

Whilst the AER does not support an MRP estimate derived from implied volatility rates, it does note the significant downward trend in the 20-day moving average of implied volatility, as depicted below. The AER considers this as further evidence that equity market volatility is waning and does not justify a departure from a 6.5 per cent estimate for the MRP.

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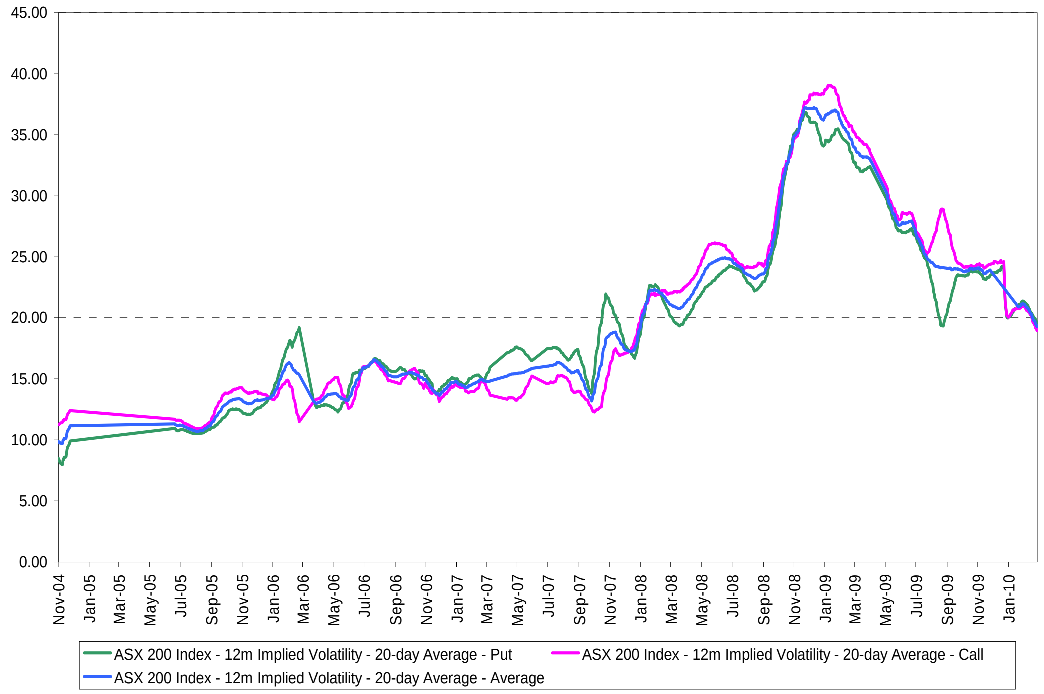
69 AER, *Review of the weighted average cost of capital (WACC) parameters*, Final decision, 1 May 2009, pp. 237–238.

70 R. R. Officer and S. Bishop, *Market risk premium, Report prepared for ETSA*, 26 June 2009, p. 11.

Figure 11.4 Implied volatility



Source: Bloomberg; AER analysis

Cost of debt and the cost of equity

Officer and Bishop also attempt to derive a forward looking view of the MRP from the credit spreads between corporate debt and CGS yields. Officer and Bishop note:

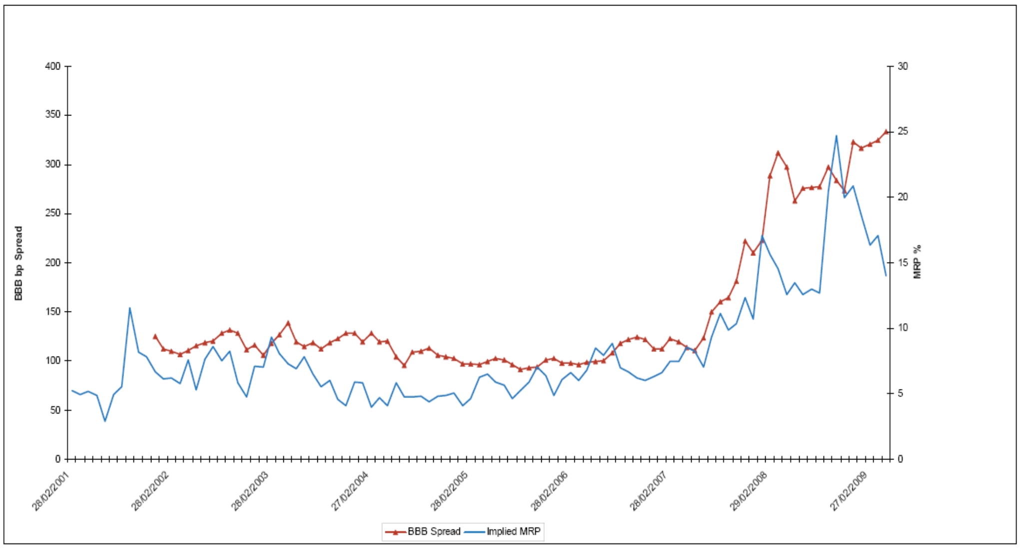
> Corporate debt is a risky asset and can be priced according to the CAPM. In this context, the rise in the spread can be explained by either an increase in the MRP, an increase in beta or some combination.[71]

Officer and Bishop note that it is not clear whether the rise in credit spreads can be attributed to the MRP or the debt beta. However, it is unlikely that the debt beta would rise significantly over time; rather the rise in credit spreads is more likely attributable to a rise in the MRP.[72] Officer and Bishop cite Bloomberg data that calculates the risk premium of BBB-rated, 7-year corporate bonds to demonstrate the path of credit spreads over time relative to the MRP. The graph used by Officer and Bishop to demonstrate is shown as figure 11.5.

71 R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p. 15.

72 ibid., p. 16.

Figure 11.5 Risk premium on BBB rated 7 year corporate bonds versus implied MRP from VIX data



Source: Bloomberg; R. R. Officer and S. Bishop, *Market risk premium—Estimate for 2011–2015*, Report for DNSPs, October 2009, p. 16.

Furthermore, Officer and Bishop provide an assessment of the relationship between the cost of debt and equity, and make the observation that:

> It is important to recognise that there will be considerable symmetry between the cost of equity and the cost of debt. The spread on BBB rated debt is currently of the order of 380 basis points above 10 year Treasury Bonds. This spread has risen from a spread in less volatile economic conditions of 120 basis points. Since this rise is reflective of current economic conditions then we would expect a commensurate rise in the risk premium for equity. It is unlikely that there would be a narrowing of the spread between the cost of debt and equity under current conditions, rather than a widening might be expected.[73]

The AER highlights that Officer and Bishop have 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). 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.

Additionally, the results from figure 11.6 below demonstrate the decline in the DRP since the 1 May 2009 (release of the SORI) to 19 March 2010, with the trend reduction in credit spreads representing a further sign of stabilisation in financial markets. While the AER acknowledges the submissions of the EUCV and CALC and agrees that increasing the MRP from 6.5 per cent to 8 per cent is unjustified the current market circumstances, it considers that there is not sufficient market evidence to suggest a 6 per cent MRP should be used in the current determination.

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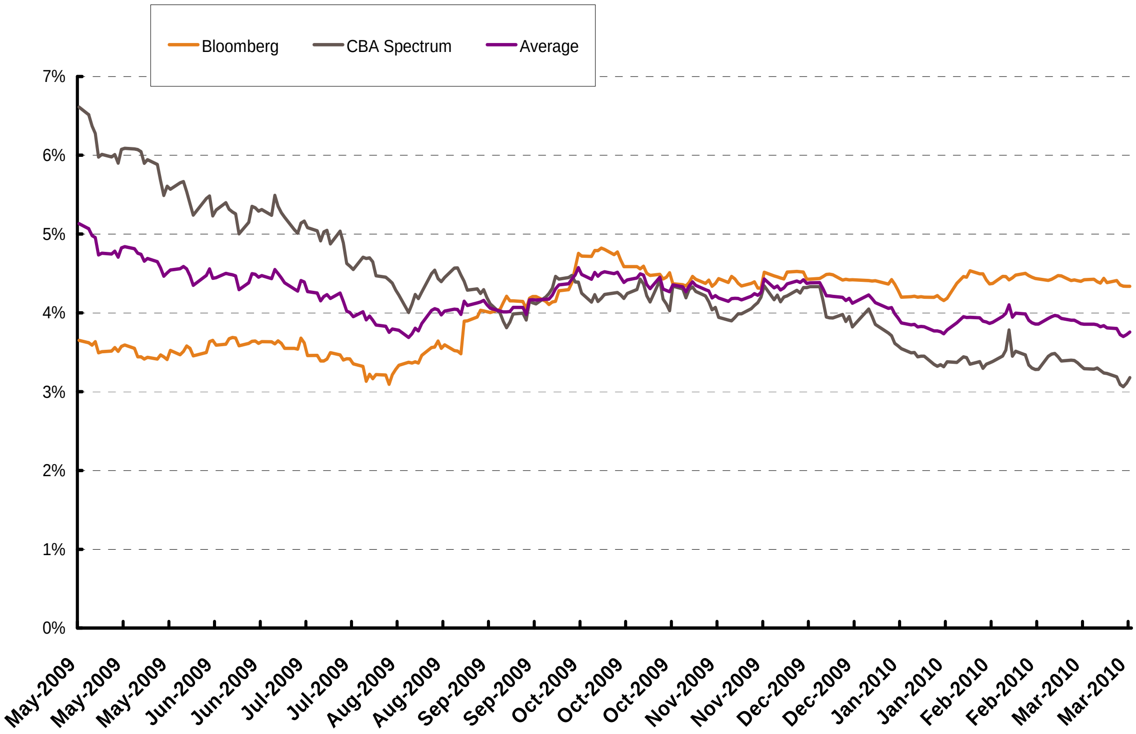
[73] ibid., p. 16.

Figure 11.6 DRP—Implied from the difference between the 10 year BBB-rated and CGS curves



Source: Bloomberg; CBA Spectrum; AER analysis.

AER conclusion

The AER considers that the Victorian DNSPs' proposals do not represent persuasive evidence justifying a departure from the 6.5 per cent MRP in the SORI. The AER considers:

- commentary on financial markets indicates clear signs of stabilisation since the time of the AER's SORI and its decision to increase the MRP to 6.5 per cent
- Officer and Bishop's implied volatility and glide path analysis is subject to limitations as addressed by the AER in previous regulatory determinations
- no persuasive evidence exists to support a long term historical average of 7 per cent for the MRP as assumed by Officer and Bishop
- Officer and Bishop have not adequately demonstrated that the current level of credit spreads are explained by movements in the MRP
- the AER considers that a MRP of 6.5 per cent may be considered conservative when accounting for current prevailing conditions.

11.5.4 Equity beta

The equity beta measures the standardised correlation between the returns on an individual risky asset or business with that of the overall market. In essence, it represents the 'riskiness' of a business' returns compared with that of the market. Risk results from the possibility that returns will differ from expected returns (the greater the uncertainty around the returns of a business, the greater its level of risk).

As is consistent with CAPM theory and the requirements of the NER, the equity beta should only compensate service providers for exposure to non-diversifiable (systematic) risk, and not compensate for diversifiable (non-systematic) risk. Non-diversifiable risk refers to the macroeconomic or market-wide risk factors that affect the returns of all businesses in the economy—though to varying degrees—and include factors such as changes or volatility in inflation, gross domestic product growth, interest rates, commodity prices, foreign exchange rates and changes in tax laws.

The equity beta (for a particular asset or business) scales the MRP up or down to reflect the risk premium—over and above the risk-free rate—equity holders would require to hold that particular risky asset or business as part of the investor's well-diversified portfolio.

An equity beta of one implies that the business' returns have the same level of systematic risk as the overall market. An equity beta of less than one implies the business' returns are less sensitive to systematic risk than the overall market, and an equity beta greater than one implies the business' returns are more sensitive.

Regulatory requirements

The SORI specifies an equity beta of 0.8.[74]

The AER considers the underlying criteria relating to the NER requirements that are of particular relevance to determine the equity beta are:

- the need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services
- 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.[75]

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[74] AER, *Statement of regulatory intent*, 1 May 2009, p. 7.

DNSPs regulatory proposals

The Victorian DNSPs proposed to adopt the parameter value specified in the SORI for the equity beta.[76]

Issues and AER considerations

In accordance with the underlying criteria, the AER considers the proposed equity beta:

- is supported by the most recent available and reliable empirical evidence, which the AER considers does not support a change to the existing value in the SORI
- generates a forward looking rate of return that is commensurate with prevailing conditions in the market for funds
- together with values, methods and a credit rating for the other parameters, provides a service provider with a reasonable opportunity to recover at least the efficient costs and provides a service provider with effective incentives for efficient investment
- is appropriate having regard to the economic costs and risks of the potential for under and over investment.

On this basis, the AER considers that the proposed value achieves an outcome that is consistent with and is likely to contribute to the achievement of the NEO.[77]

AER conclusion

The equity beta of 0.8 proposed by the Victorian DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

11.5.5 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).

75 NER, clause 6.5.4(e) and NEL, Part 1, section 7A.

76 CitiPower, *Regulatory proposal*, p. 299; Jemena, *Regulatory proposal*, p. 173; Powercor, *Regulatory proposal*, p. 307; SP AusNet, *Regulatory proposal*, p. 287; and United Energy, *Regulatory proposal*, p. 139.

77 NER, cl 6.5.4(e).

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.[78] The underlying criteria used by the AER in its SORI in relation to the credit rating level were:

- 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:
  - 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.[79]

78 AER, *Statement of regulatory intent*, 1 May 2009, p. 7.
79 NEL, Part 1, section 7A.

DNSPs regulatory proposals

All DNSPs proposed an indicative DRP of 4.71 per cent based upon a BBB+ credit rating.[80] This value was estimated from Bloomberg's 7-year BBB rated fair yield curve, using linear extrapolation to calculate the 10 year yield of 4.71 per cent.

The Victorian DNSPs' proposals are based upon a report provided by PricewaterhouseCoopers (PwC), *Methodology to estimate the debt risk premium*. Overall, PwC comments that the GFC has created uncertainty of the bond market, and the difficulty that this poses for estimating the yield for a benchmark 10 year BBB+ rated bond.[81]

PwC's report addresses two aspects of the DRP estimation methodology, which are:[82]

- the reliability of the Bloomberg service as a data provider
- a recommendation to use a linear extrapolation to estimate bond yields.

Reliability of the Bloomberg estimation methodology

PwC identified and analysed the three main stages of Bloomberg's estimation methodology:

1. Collection of Institutional data feeds for all bonds with appropriate credit ratings.
2. Calculation of Bloomberg's generic yield estimates (BGNs) - yield estimates are calculated for each of the sampled bonds calculated from Institutional feeds.
3. Estimation of Bloomberg's fair yield curve (BFV), which is calculated as a composite of the BGNs.

PwC assessed the reliability of each stage of the methodology over the first 15 trading days of October 2009 by applying tests of variance. PwC noted:

> The reliability of Bloomberg's fair value curve may be questioned as the BGNs are based on poor data and/or do not reliably reflect all available information. This chapter proposes three tests, each corresponding to one of the foregoing observations, to assess whether or not Bloomberg can be relied upon. Each test measures the divergence in the relevant variables, compared to a benchmark limit of divergence that is established on the basis of historical data.[83]

Each of the tests that PwC applied to Bloomberg's estimation methodology is discussed briefly in turn.

Test 1—Coefficient of Variation in bank feeds

The first test calculates the variability of estimated yields among institutional feed sources. The institutional feeds either directly estimate yields from the prices of actual

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[80] United Energy, *Regulatory proposal*, p. 148; CitiPower, *Regulatory proposal*, p. 299; Powercor, *Regulatory proposal*, p. 307; Jemena, *Regulatory proposal*, p. 174, SP AusNet, *Regulatory proposal*, p. 299.

[81] PwC, *Methodology to Estimate the Debt Risk Premium*, Report prepared for the Victorian distribution businesses, November 2009, p. 17.

[82] ibid., p. 3.

[83] ibid., p. 22.

bond trades and issues, and/or from institutions' opinions of prices for hypothetical bond trades.[84]

PwC asserted that significant divergence between institutional feeds implies the feed data will be of poor quality, and suggested that variability among institutional feeds should be estimated and assessed as a coefficient of variation calculation.[85] The coefficient of variation measures the difference between bank feeds as a proportion of the average bank feed observations and is represented mathematically as:

$$C_v = \sigma/\mu$$

Where:

C_v = coefficient of variation

σ = sigma: represents the deviation among bank feed observations for each bond

μ = mean: the average of bank feed data

If the coefficient exceeds 5 per cent, test 1 is failed, where 5 per cent is considered the acceptable threshold given historical estimates of the coefficient of variation.[86]

In the event of failure, PwC recommend the AER should still place primary weight on Bloomberg fair yield estimates and in addition, should rely on adjusted floating rate bond data and term sheets of bank debt transactions.[87]

Test 2—Average differential: Bloomberg BGN and mean bank feed yields
The second test assesses the variability between institutional feeds and the corresponding fair yields for each of the individual bonds (BGNs). PwC asserted that the BGN yield estimates can (on average) be considered reliable when they closely reflect the average yields of the institutional feeds.[88]

To calculate the variability, PwC proposed using the average differential between the BGN and mean of the bank feeds, expressed as a percentage of the BGN. The average difference should be calculated at each bond's maturity and reflect all bonds included on Bloomberg's BBB fair yield curve.

An average differential greater than 2.5 per cent suggests a difference greater than the historical average and a failure of test 2.[89] If test 2 is failed, PwC recommended the AER develops its own yield estimates, based upon the mean yield estimates of the bank feeds.[90]

84 PwC, *Methodology to estimate the debt risk premium*, Report prepared for the Victorian distribution businesses, November 2009, p. 18.
85 ibid., p. 22.
86 ibid., p. 24.
87 ibid., pp. 42–43.
88 ibid., p. 24.
89 PwC, *Methodology to estimate the debt risk premium,* Report prepared for the Victorian distribution businesses, November 2009, p. 26.
90 ibid., pp. 41–42.

Test 3—Mean Bloomberg yield differential from BFV curve

The third test assesses Bloomberg's method to fit each of the BGN estimates to a single BFV curve.

PwC noted that in attempting to form an unbiased, best fit curve, Bloomberg makes subjective decisions to exclude some BGNs as outliers from the BFV curve calculation. Test 3 is essentially an assessment of Bloomberg's choice to exclude observations as outliers.

PwC considered a BFV curve to provide a reasonably reliable representation of the underlying bond's fair value when the BFV closely fits the BGN points. Variability can be calculated as the average difference between BGN and BFV estimates for a particular maturity, expressed as a proportion of the BGN.

PwC considered where variability is above 4 per cent, test 3 is failed.[91] In this event, PwC recommended the AER conduct a form of regression (that includes all bonds in the original sample) to re-estimate the BBB fair yield curve.[92]

If all three tests are passed, PwC recommended using Bloomberg's BBB fair value curve to estimate the benchmark yield on Australian corporate bonds.[93] Over the 15 days (first 15 business days of October 2009) in which it assessed Bloomberg's estimation methodology, PwC determined that all three tests were passed and Bloomberg was therefore a reliable data provider for the period considered.[94]

Extrapolation method used to estimate the 10 year fair yield curve

PwC noted Bloomberg's fair yield curve illustrates the estimated bond yields across a range of maturities that are supported by actual bond observations. The decline in the number of listed, long-dated maturing bonds is demonstrated in PwC's report. Figure 11.3 illustrates how Bloomberg stopped publishing BFV for 8 to 10 year maturities for the AA and BBB curves.

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91 ibid., pp. 26–27.
92 ibid., p. 41.
93 ibid., p. 29.
94 ibid., p. 30.

Table 11.3 Published bonds

Bloomberg Fair value curve	Term (years)			
	7	8	9	10
AAA				
Publishing finished	N/a	N/a	N/a	N/a
Earlier periods for which curve was not published	N/a	N/a	N/a	N/a
AA				
Publishing finished	N/a	19/06/08	19/06/08	30/06/05
Earlier periods for which curve was not published	N/a	06/10/00 –28/12/01	06/10/00 –30/05/02	06/10/00 –30/05/02
BBB				
Publishing finished	N/a	N/a	10/10/07	10/10/07
Earlier periods for which curve was not published	N/a	N/a	10/04/02 –10/06/03	15/03/02 –10/06/03 and 21/10/04 –09/11/05

Source: PwC, *Methodology to Estimate the Debt Risk Premium*, Victorian Distribution Businesses, November 2009, p. 31.

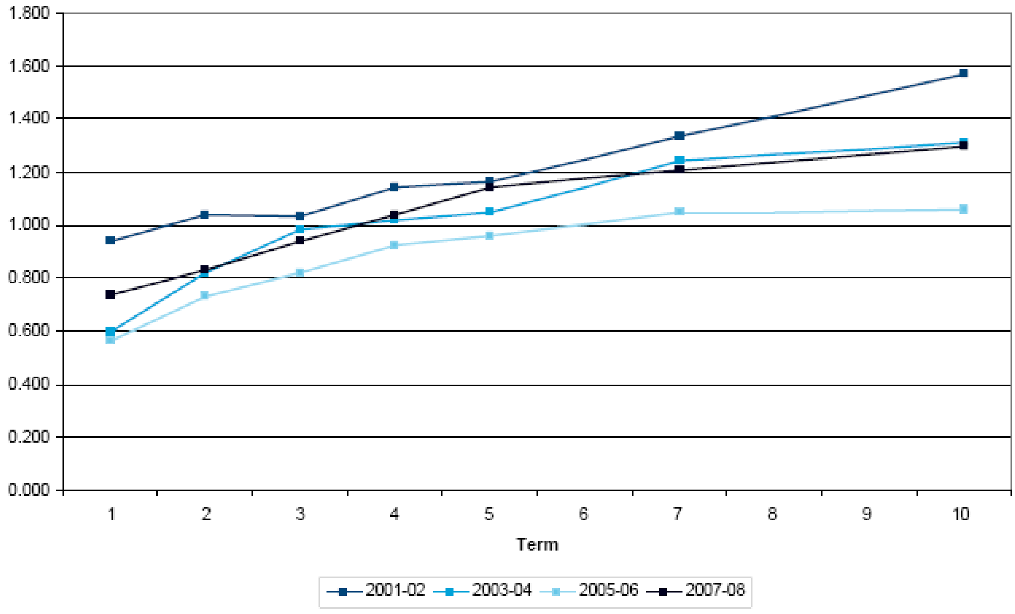
Currently, Bloomberg only publishes a BBB fair value yield curve that extends to a maturity of seven years. As such, PwC recommended a linear extrapolation of the 7 year yield to estimate the 10 year yield, expressed mathematically as follows:[95]

$$\text{DRP } 10 \text{ yr} = \text{DRP } 7 \text{ yr} + \frac{(\text{DRP } 7 \text{ yr} - \text{DRP } 5 \text{ yr})}{2/3}$$

The linear extrapolation method differs from the approach adopted by the AER in previous determinations to extrapolate from a 7 year to 10 year yield. PwC argued a linear approximation would more accurately fit the functional form of the yield curve. Figure 11.7 was provided to justify a linear extrapolation of the yield.

95 Jemena, *Regulatory proposal,* p. 174.

Figure 11.7 Comparison of yield curves



Source: PwC, *Methodology to Estimate the Debt Risk Premium*, Victorian Distribution Businesses, November 2009, p. 34.

Additionally, PwC noted the historical relationship between the yield and term to maturity for the average debt risk margins during periods when Bloomberg published the 10 year fair value curve:

> By observation we find that from a term of 4–5 years up to 10 years there has the relationship was approximately linear, the exception being the 2005–6 year, where the function appears concave.[96]

Furthermore, PwC performed a backdated analysis in support of using the linear extrapolation methodology. The analysis was conducted over those years in which the 10 year BBB fair value curve was published by Bloomberg (2001–2007). It assessed the accuracy of the linear extrapolation methodology by measuring the difference between the 10 year yield calculated using the linear extrapolation and the actual 10 year yield depicted on Bloomberg's BBB fair value curve. PwC contended that a small difference would imply that the linear approximation is an accurate estimator of the 10 year yield. Accordingly, PwC presented the results of two extrapolation methodologies, as shown in table 11.4.

96 ibid.

Table 11.4 Comparative results of linear extrapolation methodologies

	4 to 7 years		5 to 7 years	
	Δ, basis points	Δ, per cent	Δ, basis point	Δ, per cent
Median	10.6	1.51	16.2	2.34
Average	14.8	2.13	15.3	2.21
Max	50.6	7.51	53.0	7.15
Min	–6.1	–0.87	–20.9	2.97
Standard deviation	13.2	–	15.4	–

Source: PwC, *Methodology to estimate the debt risk premium*, Victorian distribution businesses, November 2009, p. 35.

PwC recommended the 5 to 7 year debt margin be used to extrapolate the 7 year BBB yield to a 10 year yield. Additionally, PWC note the 16.2 basis point median difference is small relative to the 10 year fair yield.[97]

Issues and AER considerations

The AER acknowledges the observation by PwC regarding the impact of the GFC on estimating the DRP using longer dated BBB+ rated bonds. The AER's approach has adapted over a period of time where there has been progressively less trades of bonds which meet the NER and SORI criteria. In recent determinations the AER has had to place increasing reliance on data service providers, namely Bloomberg and CBA Spectrum, whose fair yield estimates have themselves been the subject of scrutiny in an environment where corroborating information is scarce.

The following issues are considered by the AER:

- CBA Spectrum as a viable data service provider
- issues with PwC's analysis
- determining the appropriate methodology to extrapolate Bloomberg's seven year fair value curve.

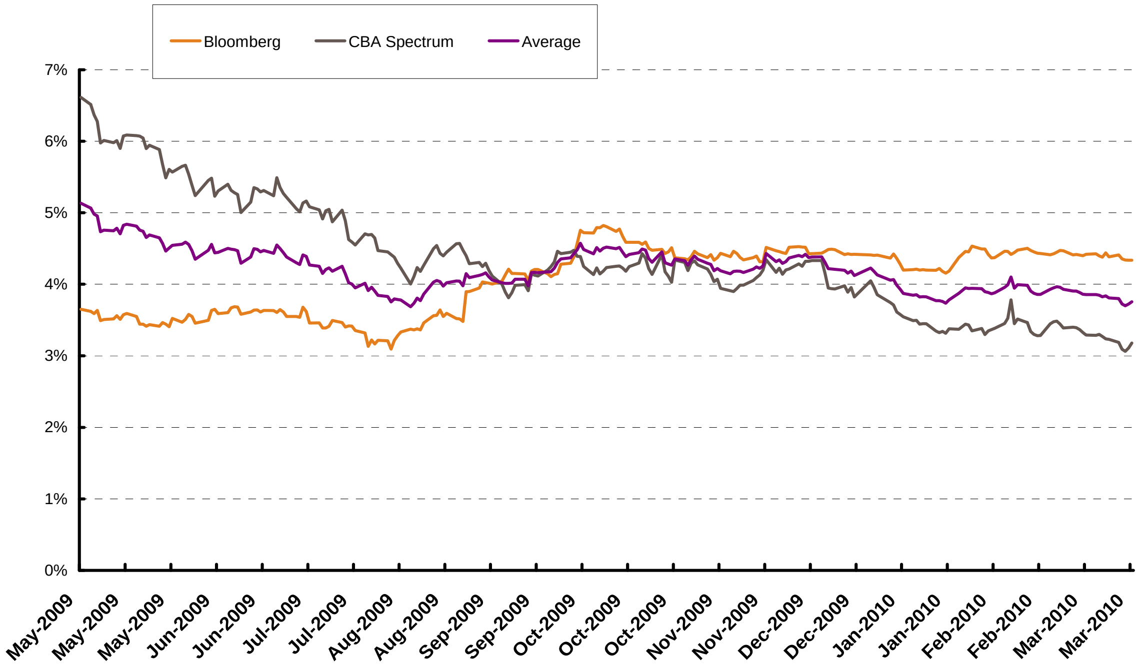
CBA Spectrum and Bloomberg as data service providers

A major issue with the Victorian DNSPs' proposals is that CBA Spectrum is ignored as an alternative data source to estimate the DRP. In recent regulatory determinations, regulatory proposals from other DNSPs (for example, ETSA Utilities) have either proposed the use of CBA Spectrum or an average of Bloomberg and CBA Spectrum.

[97] ibid., pp. 34–35.

The AER notes that since October 2009, DRP estimates using Bloomberg data have been systematically higher than those using CBA Spectrum data, as shown in figure 11.8.

Figure 11.8 Comparison of the DRP calculations of Bloomberg and CBA Spectrum[98]



Source: Bloomberg; CBA Spectrum; AER analysis.

The AER did not receive new information from the Victorian DNSPs to justify why CBA Spectrum data should be disregarded. In the absence of any compelling reason to do otherwise, the AER considers it is appropriate to consider both data services for this regulatory determination process.

Issues with PwC's analysis

The AER acknowledges the limited number of long-dated bonds now trading, and the difficulty this poses to estimate the benchmark 10 year yield for BBB+ rated corporate debt. PwC also recognised this, and advance an assessment of the Bloomberg service's fair yield curve calculation:

> In our view, the most important factor that was observed during the GFC—and in turn that caused the poor performance of the Bloomberg fair value curves—was the material rise in the level of uncertainty amongst financial institutions about the market value (and hence market yield) of the corporate bonds on issue during this time. This uncertainty no doubt was due to trade or

98 It should be noted that the risk-free rate that was used to estimate the DRP, was calculated using the RBA's methodology of linear interpolation between CGS yield observations. This is different from the CBA Spectrum's CGS yield calculation.

> new issue in these bonds almost ceasing, which left institutions without 'pegs in the sand' from which to determine their valuations.[99]

Furthermore, PwC asserted that this uncertainty was not 'dealt with well' by two proprietary elements of Bloomberg's fair yield curve estimation methodology. Specifically, PwC considered that:

- Bloomberg's estimation of market yields (implied by bond prices) were systematically lower than the central tendency of institutions' opinions of yields
- Bloomberg systematically determined higher yielding bonds as outliers and excluded these bonds from their fair yield curve calculation.[100]

PwC supported these claims by applying tests of central tendency to each stage of Bloomberg's fair yield curve methodology. PwC claimed the Bloomberg data service is reliable if the outputs at each stage of the estimation process reflect the central tendency of its inputs. This is essentially a test to assess the proprietary elements of Bloomberg's fair yield curve estimation methodology and the discretion that Bloomberg analysts use in estimation when actual market observations are limited.

The AER does not consider that this approach (in particular the first two tests) is appropriate to assess the reliability of a data service provider. Specifically, the AER considers PwC does not establish that a yield curve is more reliable merely because it reflects the central tendency of the inputs used in its estimation methodology. In addition, the AER observes that PwC has not provided any analysis that demonstrates Bloomberg's alleged underestimation of the fair yield curve. As such, the AER maintains its methodology to assess the reliability of data service providers from recent regulatory determinations (outlined below).

Additionally, PwC incorrectly estimated and applied the value of CGS yields throughout its analysis. Where gaps exist in a time-series of observed CGS yields, those missing yields are implied using an interpolation methodology. As is consistent with rule 6.5.2(d), the AER applies a linear interpolation method to estimate the CGS yields that it cannot estimate using observed market data. This method is also noted as an acceptable form of estimation in the SORI.[101] PwC has cited CGS yields published by CBA and Bloomberg that are different from the AER's CGS yield calculation methodology. The AER considers it is likely that this was an inadvertent error by PwC.

AER approach to testing Bloomberg and CBA Spectrum

It is also worth noting that PwC's third test is not all that dissimilar to the approach adopted by the AER to test Bloomberg's and CBA Spectrum BGV curves. The main point of difference is the remedy suggested in the PwC report (requiring the estimation of a yield if the mean error is greater than 5 per cent). The AER's approach

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99 PwC, *Methodology to estimate the debt risk premium*, Report for the Victorian distribution businesses, November 2009, p. 3.

100 PwC, *Methodology to estimate the debt risk premium,* Report for the Victorian distribution businesses, November 2009, p. 3.

101 AER, *Statement of regulatory intent*, 1 May 2009, p. 9.

instead uses the size of the errors within each estimation technique to determine the most appropriate data service.

The AER considers that given the lack of appropriate alternatives, a comparison of Bloomberg's or CBASpectrum's fair value estimates with a number of observed (BBB+ rated) 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, the assessment of providers of financial information has included a simple average of Bloomberg and CBASpectrum fair yield estimates in the analysis.[102] The simple average has been included for consistency and will only be relied upon where it is found that neither Bloomberg nor CBASpectrum are a better predictor. However, in most circumstances, the AER would expect that one provider would be a better predictor at any given time. As noted above, the AER will consider further refinements to its approach in setting the DRP in the future.

In conducting this comparative analysis for the Victorian DNSPs, the observed yields of a common sample of BBB+ rated bonds (with a maturity of at least 2 years) from different sources are compared with the fair value estimates based on Bloomberg, CBASpectrum and 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, 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
- $Observed_{i,j}$ 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.

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

102 AER, New South Wales and Australian Capital Territory *distribution determinations, 2009-2014, Final decision,* April 2009.

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. Table 11.5 illustrates the BBB+ bond population.

Table 11.5 Population of current BBB+ rated bonds

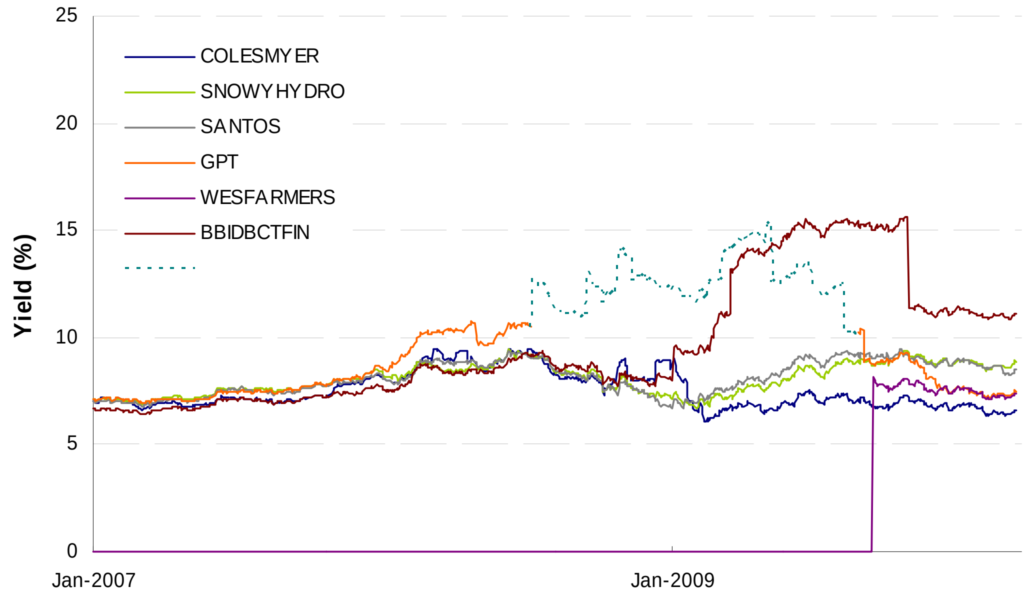
Issuer	Maturity	ISIN
Coles Myer	25 July 2012	AU300CML1014
Snowy Hydro	25 February 2013	AU000SHL0034
GPT	22 August 2013	AU300GPTM218
Wesfarmers	11 November 2014	AU3CB0126860
Santos	23 September 2015	AU300ST50076
Babcock and Brown Infrastructure	9 June 2016	AU300BBIF018

Source: Bloomberg; CBASpectrum; UBS rate sheet February 2005—19 March 2010.

Hence the AER excludes bonds from the sample on the basis they do not have certain characteristics that are reflective of the benchmark corporate bond, or if bond yields suggest the bond is an outlier.[103] The AER first determines outlier observations on the basis of identifying a structural break in the data. 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 11.9 shows the observed yields from the population of the BBB+ bonds.

[103] BBB+ fixed rate corporate bonds, with a maturity over two years, issued in Australia by Australian companies with observations available from Bloomberg, CBASpectrum and UBS over the averaging period.

Figure 11.9 Yields from the population of the BBB+ bonds, UBS



Source: UBS; AER analysis.

The identification of a structural break must, initially, be made on the basis of an inspection of the data and confirmed by the application of the Chow test. 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.[104]

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.

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.[105] 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.[106] 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.

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[104] Chow, G. C., *Tests of equality between sets of coefficients in two linear regressions*, Econometrica 28(3), July 1960.

[105] 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.

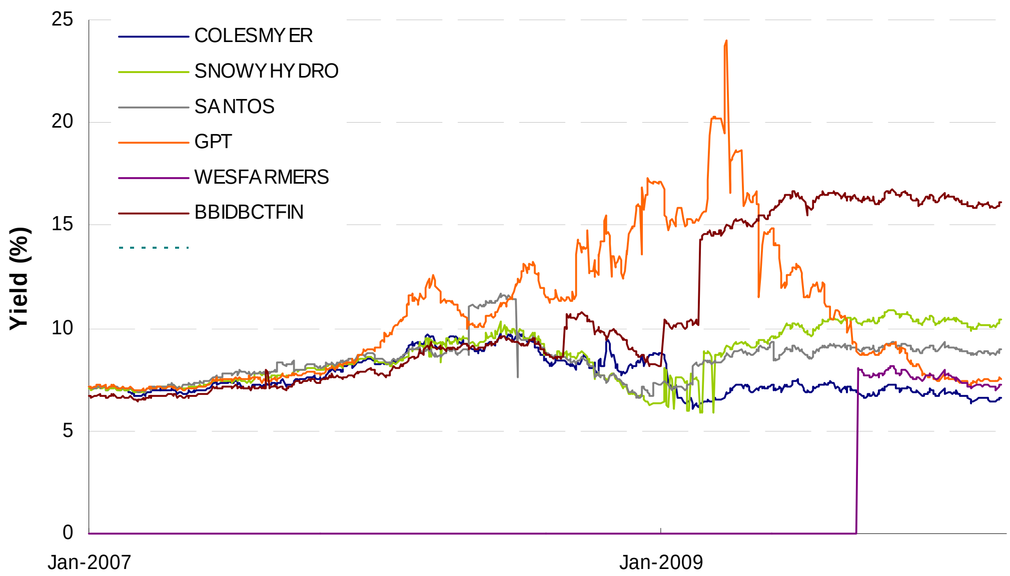
[106] Babcock and Brown, *Suspension from official quotation*, 12 January 2009.

The AER also applies the following tests to the period after which a structural break is identified to give an on-going assessment of whether a bond is an outlier:

- Chauvenet's test—an observation is an outlier if it lies outside a confidence interval of the mean with a level of significance of 1/2n where n is the number of observations in the sample
- classic outlier test—an observation is an outlier if it lies further than two standard deviations from the mean
- box plot test—an observation is an outlier if it exceeds the 75th percentile by 1.5 times the interquartile range or lies below the 25th percentile by 1.5 times the interquartile range.

The tests were applied over the period 2 January 2010 (beginning of the structural break for the Babcock and Brown Infrastructure Bond) and 19 March 2010 (end of the averaging period for the current distribution process). It was identified that the average yield for all bonds during this period was 7.88 per cent (not including the Babcock and Brown Infrastructure bond), whilst the average of the Babcock and Brown bond was 12.81 per cent. Using these input parameters, the results of all tests determined that the Babcock and Brown Infrastructure bond was an outlier. A visual inspection of bond yields, which shows the Babcock and Brown bond yields as clearly divergent from the population of other BBB+ rated bonds. This can be seen in figure 11.10 below.

Figure 11.10 Yields on the BBB+ population of bonds, CBA Spectrum



Source: CBA Spectrum; AER analysis.

Table 11.6 outlines the average bond yields observed from Bloomberg, CBASpectrum and UBS, and average fair value estimates for the sample of bonds over the averaging period, 1 March to 19 March excluding outliers. It should be noted that the Babcock and Brown Infrastructure bond was determined to be an outlier and therefore excluded from the analysis.

Table 11.6 Sample of BBB+ bonds—observed yields and fair values between 1 March to 19 March 2010 (per cent)

Issuer	**Average observed yield**			**Average fair value**	
	Bloomberg	CBASpectrum	UBS	Bloomberg	CBASpectrum
Coles Myer	6.57	6.52	6.54	6.85	6.38
Snowy Hydro	8.54	10.24	8.76	7.25	7.10
GPT	7.37	7.45	7.39	7.57	7.61
Wesfarmers	7.27	7.20	7.28	8.02	7.92
Santos	8.80	8.85	8.36	8.71	8.17

Source: Bloomberg; CBASpectrum; UBS; AER analysis.

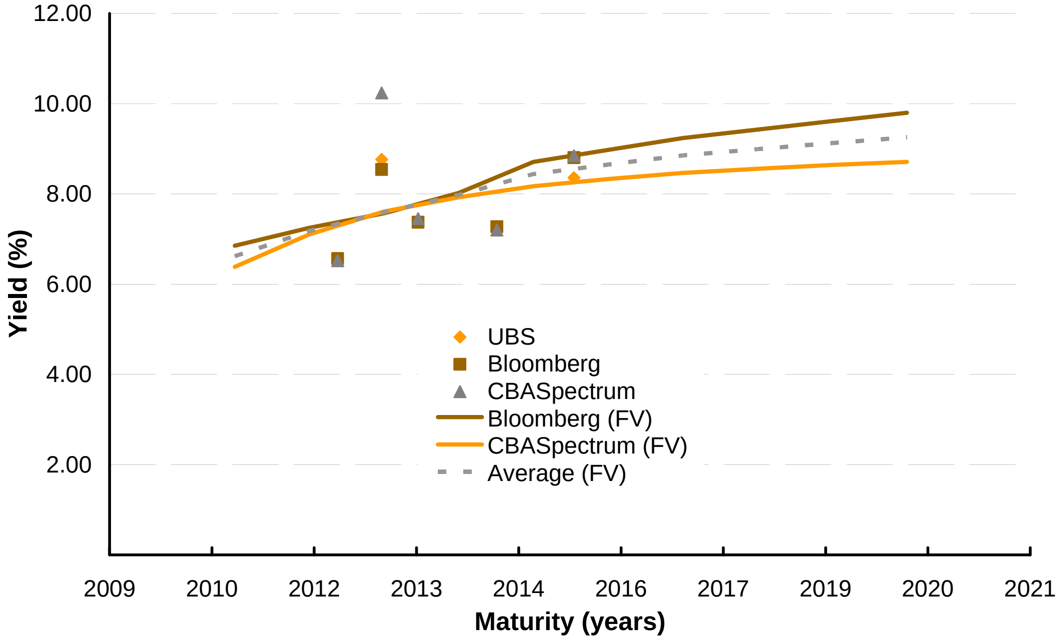
The observed yields were compared to the Bloomberg BBB fair value curve, the CBASpectrum BBB+ fair value curve and a simple average of the two curves using the weighted sum of squared errors. This comparison provided the results shown in table 11.7.

Table 11.7 Fair value and observed yield analysis using weighted sum of squared errors between 1 March to 19 March 2010 (per cent)

	Fair value source		
Observation source	Bloomberg	CBASpectrum	Average
UBS	0.75	0.54	0.62
Bloomberg	0.63	0.53	0.56
CBASpectrum	1.88	1.75	1.79

Source: Bloomberg; CBASpectrum; UBS; AER analysis.

Figure 11.11 Fair value and observed yield analysis



Source: Bloomberg; CBASpectrum; UBS; AER analysis.

For the sample of bonds over the period 1–19 March 2010, CBASpectrum's BBB+ fair value curve best matches the observed yields.

The AER notes 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.

This approach was also taken to assess the reliability of data service providers in the New South Wales distribution determination. In its recent review of the AER's New South Wales distribution determination, the Australian Competition Tribunal also affirmed the AER's method of comparing the fair yield curves of data service firms against the actual bond yields to assess the reliability of data service providers.[107]

Extrapolation methodology

Given that the AER has determined the use of CBA Spectrum for the purposes of this draft decision, the issue of extrapolation does not affect the value of the DRP determined here. However this section addresses the issue of extrapolating Bloomberg data as it was raised by PwC and may be relevant for the AER's final decision.

From 9 October 2007, Bloomberg ceased publishing a 10 year BBB fair yield, which the AER had used as the estimate for the benchmark cost of debt. In response, the AER observed Bloomberg's next longest dated (8 year) BBB fair yield, and applied a proxy extrapolation method to produce an approximate value of the 10 year BBB fair

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107 Australian Competition Tribunal, Application by Energy Australia and Others (No 2) [2009] ACompT 8, 12 November 2009

yield. This involved adding the spread between the eight and ten year A rated fair yields to Bloomberg's eight year BBB fair yield, to estimate the cost of BBB+ corporate debt with a maturity of 10 years. There is currently no longer a reliable sample set of A and AA rated bonds that can be used for proxy extrapolation.[108]

Since 19 August 2009, Bloomberg only publishes a BBB fair yield that extends as far as seven years.[109] The AER has performed a backdated analysis to compare how various proxies can be used in extrapolation. The backdated analysis assesses how linear extrapolation compares against each of the proxy extrapolation methods in estimating the10 year BBB+ benchmark cost of debt.

PwC proposed a linear extrapolation methodology should be used to estimate the 10 year fair yield from Bloomberg's BBB, 7 year fair yield curve.[110] The AER notes that PwC did not compare the linear extrapolation method against any other alternative extrapolation methods. For the purposes of comparison, the AER has therefore performed a backdated analysis to determine the accuracy of both the linear and proxy extrapolation methods.

The AER considers a number of possible data sources for overcoming this data limitation. The data sources are:

- Bloomberg's AA and AAA fair value curves
- Bloomberg's CGS fair value curve
- Bloomberg's semi-government fair value curves (NSW, VIC, QLD and WA)
- Bloomberg's interest rate swaps curve
- a linear extrapolation based on the spread between the Bloomberg five and seven year BBB fair value estimates.

For the first four sources the difference between the seven and 10 year yield is used to extrapolate Bloomberg's BBB fair value curve to a term of 10 years. For the last source the difference in maturity between the yields is only two years so the spread is multiplied by 1.5 to estimate a three year spread. This linear extrapolation method is consistent with the method that PwC used in its report.

The AER evaluates these options by comparing each extrapolated 10 year fair value curve to the Bloomberg BBB fair value curve over the period from 10 November 2005 to 9 October 2007. This period is selected because it represents the most recent period for which the Bloomberg 10 year BBB fair value curve is available.

The difference between the extrapolated curve and the actual Bloomberg BBB fair value curve on each day during the period is squared and averaged over this period. This measurement is called the mean squared difference. A lower mean squared

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108 AER minute, *Testing and extrapolating fair market curves*, Jan 2010, p. 9.
109 ibid.
110 PwC, *Methodology to estimate the debt risk premium*, Report for the Victorian distribution businesses, November 2009, p. 35.

difference indicates a more accurate extrapolation. The results of this analysis are shown in table 11.8.

Table 11.8 Results of testing of extrapolation methods

Extrapolation method	Mean squared difference
Bloomberg AA	N/a
Bloomberg AAA	0.0025
Bloomberg CGS	0.0041
Bloomberg NSW	0.0048
Bloomberg VIC	0.0053
Bloomberg QLD	0.0047
Bloomberg WA	0.0049
Bloomberg interest rate swaps	0.0047
Average of linear and AAA proxy extrapolation methods	0.0048
Linear	0.0122

N/a: Not available, as Bloomberg did not publish a AA fair value curve over the required maturities during the period under consideration.
Source: AER analysis

Based on this analysis, the AER considers that the spread between Bloomberg's AAA seven and ten year fair value estimates provides a reasonable approach to extrapolating Bloomberg's BBB fair value curve to a term of 10 years, as reflected in having the lowest mean squared difference. Therefore, the AER proposes that a proxy extrapolation method, using AAA rated fair yields should be used to estimate the 10 year BBB+ benchmark cost of debt where Bloomberg data is used.

AER conclusion

The credit rating level of BBB+ proposed by the Victorian DNSPs is as specified in the SORI and is accepted by the AER in accordance with clause 6.5.4(g) of the NER.

With respect to the supporting information (PwC report) provided by the Victorian DNSPs, the AER considers:

- it is appropriate to consider both Bloomberg and CBA Spectrum as data service providers for consideration in the calculation of the DRP
- its approach to testing both CBA Spectrum and Bloomberg data is appropriate and has been affirmed by the Australian Competition Tribunal

- PwC's linear extrapolation methodology is inappropriate, and considers that a proxy extrapolation using AAA fair yields would better estimate the 10 year BBB+ cost of debt.

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. Unlike the Victorian DNSPs' proposed use of Bloomberg data, CBASpectrum's BBB+ fair value curve meets the need for the return on debt to reflect the current cost of borrowings for comparable debt.

This conclusion 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 over the indicative averaging period of 15 days ended 19 March 2010. The DRP estimated using this process for the purposes of this draft decision is 3.25 per cent.

The DRP will be updated for the AER's final determination on the basis of data and analysis relating to the averaging periods accepted by the AER.

11.5.6 Expected inflation

The expected inflation rate is not an explicit parameter within the WACC calculation. However, it is used in the PTRM to forecast nominal allowed revenues and to index the RAB.

The AER has previously determined[111] 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.[112]

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 Australian Capital Territory distribution determination final decision stated:

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[111] AER, Australian Capital Territory *Distribution determination, Final decision,* April 2009, p. xxi; and Australian Capital Territory *Distribution determination, Final decision,* April 2009 p. xxxviii.

[112] 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.

> … 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.[113]

DNSPs regulatory proposals

The Victorian DNSPs adopted the approach used by the AER in the New South Wales and Australian Capital Territory distribution determinations for determining the inflation rate.[114]

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.[115] 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. Since late 2006, however, 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.

The Australian Office of Financial Management (AOFM) has recommenced issuing index linked CGS since 16 November 2009.[116] The AER considers that, while the yields from indexed CGS are likely to be unreliable for the purposes of the Victorian distribution determination process due to the limited supply of these securities, it will re-examine this issue for future regulatory processes.

In the absence of a credible market–based inflation forecasting methodology, the AER considers that the methodology adopted in the New South Wales and Australian Capital Territory 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.

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113 AER, Australian Capital Territory *Distribution determination, Final decision,* April 2009, p. xxi.

114 CitiPower, *Regulatory proposal*, p. 307; Jemena, *Regulatory proposal*, p. 164; Powercor, *Regulatory proposal*, , p. 315; SP AusNet, *Regulatory proposal*, p. 295; and United Energy, *Regulatory proposal*, p. xxiv.

115 NER, cl. 6.4.2(b)(1).

116 AOFM, *Treasury indexed bonds—resumption of issuance and participation in syndicate*, Operational notice, viewed 23 March 2010, http://www.aofm.gov.au/content/notices/24_2009.asp.

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.[117] The AER observes only Jemena used the correct values and methodology to calculate the forecast inflation figure in its regulatory proposal. That said, the AER considers errors made by the other DNSPs were inadvertent. Based on this approach and using the latest RBA forecasts as shown in table 11.9, an inflation forecast of 2.57 per cent produces the best estimate for a 10 year period.[118]

Table 11.9 AER conclusion on inflation forecasts (per cent)

	Dec 2011	Dec 2012	Dec 2013	Dec 2014	Dec 2015	Dec 2016	Dec 2017	Dec 2018	Dec 2019	Dec 2020	Geometric average
Forecast inflation	2.75	3.00	2.50a	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.57

(a) The RBA has not yet released a forecast for the year ending December 2013. This forecast will be available and adopted by the AER (including any update forecasts) at the time of the final decision. The midpoint of its target inflation band has been assumed for the purposes of this draft decision.

Source: RBA, *Statement on monetary policy*, 6 May 2010, p. 56.

11.6 AER conclusion

In accordance with clause 6.12.1 (5), the AER's draft decision on the rate of return is set out below. The AER's decision on the cost of capital can also be found in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

The SORI defines WACC parameter values and methods that must be used in a distribution determination for the purposes of setting a rate of return unless there is persuasive evidence for a departure.

For this draft decision, the AER has determined a nominal vanilla WACC of 9.68 per cent for the Victorian DNSPs, which is lower than the 10.86 per cent proposed.[119] The difference owes to the AER:

- rejecting the Victorian DNSPs' proposed estimation of the DRP by considering only data from Bloomberg, which according to the AER's analysis would not meet the need for the return on debt to reflect the current cost of borrowings for comparable debt

- rejecting the proposed MRP of 8 per cent, on the basis that the Victorian DNSPs' proposals did not constitute persuasive evidence to depart from 6.5 per cent

117 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, viewed 26 June 2009, http://www.rba.gov.au/MonetaryPolicy/statement_conduct_mp_4_06122007.html.

118 The AER notes that this will be updated to incorporate the latest available data at the time of the final decision.

119 See for example, Jemena, *Regulatory proposal*, p. 161.

- updating the nominal risk-free rate for a 15-day period ended 19 March 2010 (from 5.47 to 5.65 per cent).

Table 11.10 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and debt risk premium, based on the proposed averaging period, and the expected inflation rate at a time closer to their final determination.

Table 11.10 AER conclusion on WACC parameters

Parameter	CitiPower	Powercor	Jemena	SP AusNet	United Energy
Nominal risk-free rate	5.65%	5.65%	5.65%	5.65%	5.65%
Real risk-free rate	3.00%	3.00%	3.00%	3.00%	3.00%
Expected inflation rate	2.57%	2.57%	2.57%	2.57%	2.57%
Gearing level (debt/equity)	60%	60%	60%	60%	60%
Market risk premium	6.5%	6.5%	6.5%	6.5%	6.5%
Equity beta	0.8	0.8	0.8	0.8	0.8
Debt risk premium	3.25%	3.25%	3.25%	3.25%	3.25%
Nominal pre-tax return on debt	8.90%	8.90%	8.90%	8.90%	8.90%
Nominal pre-tax return on equity	10.85%	10.85%	10.85%	10.85%	10.85%
Nominal vanilla WACC	9.68%	9.68%	9.68%	9.68%	9.68%

12 Estimated corporate income tax

12.1 Introduction

This chapter sets out the AER’s assessment of the estimated corporate income tax liabilities proposed by the Victorian distribution network service providers (DNSPs) 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.

12.2 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 National Electricity Rules (NER). This clause provides the following formula for the calculation of the estimated cost of corporate income tax (ETCt) 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.

The AER's post-tax revenue model (PTRM) calculates a DNSP's tax liability building block in accordance with clause 6.5.3 on the basis of other values inputted by the DNSP and the AER. In particular, the PTRM calculates required revenue for each DNSP, from which tax expenses (opex, interest payments on debt and total tax depreciation for all assets) are deducted to arrive at the DNSP's taxable income. Taxable income is multiplied by the corporate income tax rate, then again by one minus the utilisation of imputation credits (gamma) to arrive at the tax building block for the DNSP.

Clause 11.17.2 also contains Victorian specific transitional requirements for the regulatory control period commencing 1 January 2011:

> …
>
> (b) For calculating the estimated cost of corporate income tax, the AER must adopt:
>
> (1) the taxation values of assets carried over from the ESC distribution pricing determination; and
>
> (2) the classification of assets, and the method of classification, adopted for the ESC distribution pricing determination; and
>
> (3) the same method of depreciation as was adopted by the ESC for the ESC distribution pricing determination.
>
> (c) The AER may, however, depart from methods of asset classification or depreciation mentioned in paragraph (b)(2) or (3) to the extent required by changes in the taxation laws or rulings given by the Australian Taxation office.

The formula outlined in clause 6.5.3 above incorporates a value for imputation credits (γ or gamma) in determining the appropriate company tax allowance. Under the Australian imputation tax system, domestic investors receive a credit for tax paid at the company level (an imputation credit)[1] that offsets part or all of their personal income tax liabilities. For eligible shareholders, imputation credits represent a benefit from the investment in addition to any cash dividend or capital gains received.[2]

The generally accepted regulatory approach to date in Australia has been to define the value of imputation credits in accordance with the Monkhouse definition.[3] Under this approach, gamma is defined as a product of the 'imputation credit payout ratio' (F – payout ratio) and the 'utilisation rate' (θ – theta).

Gamma has a range of possible values from zero to one. The AER recently determined a value of 0.65 for gamma in its Statement of Regulatory Intent (SORI).[4]

12.2.1 Statement of regulatory intent

Under clause 6.5.4(a) of the NER, the AER conducted a review of the weighted average cost of capital (WACC) which covered the following matters referred to in clauses 6.5.2 and 6.5.3 of the NER:

- the nominal risk-free rate
- the equity beta

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1 In this chapter the terms imputation credit and franking credit are used interchangeably.

2 Although foreign investors do not pay Australian personal income taxes, they may receive a credit for company tax paid from their home country government, depending on the inter-country tax arrangements.

3 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.

4 AER, *Statement on the revised WACC parameters (distribution), Statement of regulatory intent*, May 2009, p. 7.

- 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, and
- the assumed utilisation of imputation credits.[5]

On completion of the WACC review the AER issued the SORI regarding these values, methods and credit rating levels.[6] Under clause 6.5.4(g) of the NER, a distribution determination must be consistent with the relevant SORI unless there is persuasive evidence justifying a departure from a value, method or credit rating level set out in the SORI. Clause 6.5.4(h) of the NER requires that in deciding whether a departure from a value, method or credit rating level set in the SORI is justified, the AER must consider:

> (1) the criteria on which the value, method or credit rating level was set in a SORI (the underlying criteria); and
>
> (2) whether, in light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in a statement inappropriate.

The underlying criteria used by the AER in its SORI in relation to gamma are:

- the need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated distribution services
- the need to achieve an outcome that is consistent with the national electricity objective
- the need for persuasive evidence before adopting a value or method that differs from the value or method previously adopted, and
- the relevant revenue and pricing principles, which are:
  - providing a service provider with a reasonable opportunity to recover at least the efficient costs
  - providing a service provider with effective incentives in order to promote efficient investment, and

---

5 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.

6 AER, *Statement of regulatory intent*, 1 May 2009.

- having regard to the economic costs and risks of the potential for under and over investment.[7]

12.3 Summary of Victorian DNSP regulatory proposals

12.3.1 Assumed utilisation of imputation credits (gamma)

The DNSPs proposed to depart from the gamma value defined in the SORI. CitiPower, Powercor, SP AusNet and United Energy proposed a value of 0.5, while Jemena proposed a value of 0.2.[8]

The DNSPs, in conjunction with ETSA Utilities, engaged Associate Professor Skeels to review the position taken by the AER with respect to the selection of theta (0.65) in the WACC review. Two reports prepared by Skeels were provided as supporting information for the DNSPs' regulatory proposals.[9]

In addition to the Skeels reports, Jemena provided reports by Professor Officer, Synergies and Mr Feros, a tax partner at Gilbert and Tobin to support its position on the imputation payout ratio (0.66) and theta (0.3).[10]

12.3.2 Estimation of corporate income tax liability

In estimating corporate income tax liability for the forthcoming regulatory control period, each DNSP submitted to the AER tax roll forward models which calculated the closing and opening asset values for each year of the current regulatory control period as well as forecast values for the forthcoming regulatory control period.

Each DNSP was also required, as part of its regulatory proposal, to submit a completed PTRM which calculates the tax building block for the DNSP. Table 12.1 shows the forecast annual tax building block for each DNSP from the regulatory proposal submitted to the AER.

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7 NER, cl. 6.5.4(e); and NEL, section 7A.

8 CitiPower Pty, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 307; Jemena *Regulatory proposal 2011-15*, 30 November 2009, p. 176; Powercor Australia, *Regulatory proposal 2011to 2015*, 30 November 2009, p. 314; SP AusNet, *Electricity Distribution Price Review Regulatory proposal*, 30 November 2009, p. 300; and United Energy, *Regulatory proposal for Distribution Prices and Services January 2011 - December 2015*, 30 November 2009, p. 154.

9 C. L. Skeels, *Estimation of γ*, Report prepared for ETSA Utilities, 25 June 2009; and C. L. Skeels, *A review of the SFG dividend drop-off study, A report prepared for Gilbert and Tobin*, August 2009.

10 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; and Synergies, *New analysis using tax statistics, Memorandum for Energex and Ergon Energy*, May 2009.

Table 12.1 Victorian DNSP proposed annual forecast tax liability ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	10.5	11.3	11.3	11.8	13.2
Powercor	10.6	12.2	14.1	16.1	18.8
Jemena	12.5	7.7	9.6	9.9	10.1
SP AusNet	13.9	3.6	6.9	9.4	11.3
United Energy	6.8	8.3	9.9	12.8	14.7

Source: CitiPower, *Regulatory proposal*, 30 November 2009, p. 315; Powercor, *Regulatory proposal*, 30 November 2009, p. 323; SP AusNet, *Regulatory proposal*, 30 November 2009, p. 304; United Energy, *Regulatory proposal,* 30 November 2009, p. 150; and Jemena, *Regulatory proposal*, 30 November 2009, p. 175.

12.4 Summary of submissions

The AER received two submissions from interested parties on the gamma proposed by the DNSPs. The Energy Users Coalition of Victoria (EUCV) argued the value of 0.65 accommodates the points made in the supporting documents (Associate Professor Skeels and Mr Feros) provided by the DNSPs by averaging the boundaries it identified.[11]

CitiPower and Powercor submitted the documents provided by ETSA Utilities in response to the AER's draft decision for South Australia and argued the concerns raised by the AER are not material.[12]

12.5 Consultants review

The AER engaged several consultants to provide expert advice on issues relating to the estimation of gamma raised by the DNSPs, in particular the reports they submitted which were prepared previously for ETSA Utilities, Ergon Energy and Energex.

Professor Michael McKenzie and Associate Professor Graham Partington from the University of Sydney provided advice on the estimation of gamma focussing on dividend drop-off based estimates of theta. [13] McKenzie and Partington reviewed the SFG dividend drop-off study and found significant data and methodological issues.[14] McKenzie and Partington also advised that relying on one type of study such as the SFG study would be inappropriate and that much more evidence can be adduced to support the AER's gamma value.[15]

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11 Tax asset values for DNSP's were rolled forward and carried over from the ESCV's 2006-10 EDPR.

12 CitiPower/Powercor, *Regulatory proposal supporting information*, Submission in support, 22 February 2010.

13 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010 (McKenzie and Partington, *Gamma report*, 25 March 2010).

14 McKenzie and Partington, *Gamma report*, 25 March 2010, pp. 4–5.

15 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 4.

Associate Professor John Handley from the University of Melbourne provided advice on issues relating to the estimation of gamma, focussing on conceptual matters, and the use of taxation statistics in estimating gamma.[16] Handley advised that the Synergies report did not address the issue of double counting in its estimate of theta, which was identified in the Queensland draft decision.[17] Handley also advised that SFG's statements relating to the reliability of estimates of theta from tax statistics were incorrect.[18]

12.6 Issues and AER considerations

The remainder of this chapter deals with the DNSPs' proposals in relation to gamma, as well as further issues around the overall modelling of the DNSPs' tax liability building block.

12.6.1 Assumed utilisation of imputation credits (gamma)

The SORI determined a value of gamma of 0.65. Under clause 6.5.4(g), the AER must determine whether there is persuasive evidence to justify a departure from this value.

Overall the arguments and supporting consultant reports presented by the DNSPs are the same as those submitted to the AER recently by Ergon, Energex and ETSA Utilities in separate distribution determination processes. In all cases the AER has considered this material to not constitute persuasive evidence or was already considered by the AER in determining a gamma value of 0.65 during the WACC review.

Further analysis by Handley and Partington and Mackenzie is noted throughout the analysis below, in particular with respect to arguments around the payout ratio and the use of dividend drop off studies.

In the context of this recent advice and under the NER requirements, the following sections outline the AER's consideration of the DNSPs' proposals and consultant reports in terms of:

- estimating the payout ratio
- using tax statistics to infer theta
- using dividend drop-off studies to infer theta
- reasonable ranges and estimates of gamma.

Estimating the payout ratio

This section explores the ongoing arguments around two separate but inter-related matters in determining the payout ratio:

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[16] Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010.

[17] ibid., pp. 22–23.

[18] ibid., pp. 17–22.

- 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).[19]

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.[20] In effect, this means 71 per cent of all imputation credits, created in a given year, are assumed to be distributed to shareholders in that same year. Once distributed, shareholders are assumed to value these credits at between 0 and 100 per cent of their face value, which reflects the utilisation rate.

However, there was disagreement on the value of retained credits and what happens to the imputation credits which are not distributed immediately. Based on detailed consideration of all the available information, the AER's conclusions on the overall payout ratio in the WACC review were as follows:

- there was clear merit in the recommendation put forward by Handley to adopt a payout ratio of 100 per cent, in particular with respect to simplicity in the framework, and the strong theoretical grounds that a full distribution of imputation credits is appropriate for valuation purposes and consistent with the Officer WACC framework
- in accordance with the framework proposed by the National Economic Research Associates (NERA), based on a reasonable set of assumptions[21] the AER considered that a reasonable estimate of the payout ratio using the analysis suggested by NERA is between 91 and 98 per cent.[22]

On the basis of these considerations the AER concluded the issue of time value loss associated with retained credits was not significant, such that the adoption of an estimate for the payout ratio of 100 per cent was not unreasonable. A payout ratio of 100 per cent was also consistent with the influential Officer WACC framework and the modelling assumptions in the AER's PTRM.

Victorian DNSP regulatory proposal

Jemena noted the Synergies report which found the payout ratio, based upon tax statistics, from 2003 to 2007 averaged 66 per cent.[23] Jemena argued that this payout

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19 AER, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters, Final decision*, 1 May 2009, p. 415.

20 AER, *Final decision, WACC parameters*, May 2009, p. 414; and N. Hathaway and R. R. Officer, *The value of imputation tax credits*, Report, Capital Research Pty Ltd, November 2004. Note that this payout ratio has been obtained using tax statistics rather than dividend payout ratios from annual reports (which are measured differently to dividends in tax statistics).

21 Assumptions included that the discount rate was somewhere between the risk-free rate and the cost of equity, the retention period for imputation credits ranged from one to five years and a payout ratio of 71 per cent. AER, Final decision, WACC parameters, 1 May 2009, pp. 418–419.

22 AER, *Final decision, WACC parameters,* May 2009, pp. 419–420.

23 Jemena, *Regulatory proposal,* p. 178.

ratio is also consistent with the views of Feros and Officer, who reject the assumption that all imputation credits are eventually distributed to shareholders.[24]

SP AusNet and United Energy proposed a payout ratio of 100 per cent for the purposes of their regulatory proposal.[25] CitiPower and Powercor stated that the payout ratio must be less than 100 per cent.[26] All businesses referred to the concerns raised by ETSA Utilities in its regulatory proposal.[27]

Submissions

In support of their regulatory proposals, CitiPower and Powercor submitted reports prepared by NERA and SFG, which were also used in response to the South Australian draft decision by ETSA Utilities.[28]

NERA argued that a retention period of 5 years is not supported by the Australian Taxation Office's (ATO) tax statistics data.[29]

SFG disagreed with the assumption that 100 per cent of franking credits created in a given year are distributed in that same year, on the basis it was inconsistent with empirical data. SFG also noted that where the firm continues to exist and pay dividends each year, there are substantial limitations on the ability of the firm to distribute any stored credits.[30]

AER considerations

The AER has previously considered the reports by Synergies, Officer and Feros referred to by Jemena in its draft determinations for Queensland and South Australia.[31] The AER considered that this information did not constitute persuasive evidence with respect to gamma, specifically:

- much of the analysis by Professor Officer and Mr Feros was considered by the AER during the WACC review and was not new information. The AER referred interested parties to the AER's final decision[32] for detailed responses to these issues

- the Explanatory Memorandum to the New Business Tax System (Imputation) Act 2002 contemplates wastage through the presence of classes of foreign shareholders who cannot redeem imputation credits, rather than preventing their full distribution as contended by Feros

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24 Jemena, *Regulatory proposal*, p. 178.

25 CitiPower, *Regulatory proposal*, pp. 304–305; Powercor, *Regulatory proposal*, pp. 314–315; SP AusNet, *Regulatory proposal*, p. 299; and United Energy, *Regulatory proposal*, p. 150.

26 CitiPower, *Regulatory proposal*, pp. 304–305; Powercor, *Regulatory proposal*, pp. 314–315

27 CitiPower, *Regulatory proposal*, pp. 304–305; Powercor, *Regulatory proposal*, pp. 314–315; SP AusNet, *Regulatory proposal*, p. 299; and United Energy, *Regulatory proposal*, p. 150.

28 CitiPower, *Regulatory proposal*, p.305; Powercor, *Regulatory proposal*, p. 313

29 NERA, *Payout ratio of regulated firms*, Report for Gilbert and Tobin, 5 January 2010, p. 5.

30 SFG, *Response to AER draft determination in relation to gamma*, Report prepared for ETSA Utilities, 13 January 2010, p. 2.

31 AER, *Queensland Draft distribution determination 2010–11 to 2014–15, Draft decision*, November 2009, p. 207; and AER, *South Australian Draft distribution determination 2010–11 to 2014–15, Draft decision*, 25 November 2009, pp. 257.

32 AER, *Final decision, WACC parameters*, 1 May 2009, pp. 414 and 416–417.

- assuming undistributed imputation credits have zero value is unrealistic. While retained credits are potentially subject to time value decay, the process of determining whether this actually occurs would require considerable detailed investigation

- 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

- the PTRM already makes simplifying assumptions about the timing of cash flows, and the potential benefits from estimating the decay in value is outweighed by the complexity introduced by doing so.[33]

NERA stated that the AER assumes a 100 per cent payout ratio based on the fact that it is consistent with the standard WACC valuation framework (within a classical tax environment).[34] However, NERA point out that the Australian tax system is an imputation tax system, and that the AER has not presented empirical evidence to support a 100 per cent payout of imputation credits under an imputation tax system.[35]

As noted in its recent final decision for Queensland and South Australia, the AER considers that the assumption of a 100 per cent payout ratio is consistent with the Officer WACC framework, which assumes cash flows occur in perpetuity and are therefore fully distributed at the end of each period.[36] The AER has also noted previously, including in the WACC review, that the assumption of a 100 per cent payout ratio for imputation credits was based on a number of other considerations, including:

- it is consistent with the PTRM, which assumes cash flows to perpetuity and that cash flows are fully distributed at the end of each period

- there are significant difficulties in estimating the time value loss associated with retained imputation credits, but it is likely that retained imputation credits do have value

- based on an observed payout ratio from tax statistics of 71 per cent and the assumption that retained imputation credits do have value, the actual payout ratio in practice is unlikely to be significantly less than 100 per cent. [37]

NERA stated the ATO statistics indicate a payout ratio of 68 per cent and do not support an assumption that retained imputation credits are distributed within five years from when they are created.[38]

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33 AER, *Queensland Draft distribution determination, draft decision,* November 2009, p. 207; AER, *South Australia, Draft distribution determination 2010-11 to 2014-15*, Draft decision, November 2009, pp. 257–260.
34 NERA, *Payout ratio of regulated firms*, Report for Gilbert and Tobin, 5 January 2010, pp. 2–3
35 ibid., p. 7
36 AER, *South Australian Distribution determination, final decision*, May 2010, p.149
37 AER, *Final decision, WACC parameters*, May 2009, p. 420.

During the WACC review the AER concluded that the Hathaway and Officer (2004) estimate of the payout ratio of 71 per cent is reasonable for the immediate payout ratio for imputation credits.[39] NERA agreed with this point in its report prepared for the WACC review, and then applied time value considerations to the remaining 29 per cent of imputation credits retained on average each year.

NERA's latest estimate of 68 per cent is an estimate of the immediate payout ratio, and conclusions about the approximately 30 per cent of imputation credits retained each year cannot be drawn from this figure. This is consistent with Handley's advice, which stated that there is insufficient evidence to suggest that the 30 per cent of retained imputation credits will not be paid out.[40]

NERA advised the appropriate discount rate for retained imputation credits is the cost of equity.[41] The AER notes Handley's advice that retained imputation credits have already been earned and are readily available for distribution by the ATO. Handley noted that, as a result, retained imputation credits do not have the same level of risk as future cash flows that have not been earned and therefore have a discount rate that is lower than the cost of equity. Handley also noted that the discount rate may be above the risk–free rate because of the risk of bankruptcy faced by the average firm.[42]

The AER agrees with Handley and, as noted in the WACC review, considers that the appropriate discount rate for retained imputation credits is somewhere between the risk–free rate and the cost of equity.

The SFG report gave an example where a business may grow in perpetuity and finance growth through retained earnings, and the initial balance of retained imputation credits may never be distributed. SFG stated if it is assumed that a firm does not grow into perpetuity the only time retained imputation credits could be distributed is when a firm liquidates and at this point the retained imputation credits would have zero or negligible value, due to the time value loss of the retained imputation credits.[43] As is consistent with the WACC review, the AER considers that retained imputation credits can be distributed through off-market buy backs, dividend reinvestment plans and special dividends throughout the life of a firm.[44] Further, the AER has also previously noted in other decisions that ETSA Utilities own academic expert, Professor Robert Officer, considers liquidation as a 'logical extremity' this is further support of a positive value of retained imputation credits.[45]

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38 NERA, *Payout ratio of an average firm in the market: a report for Gilbert and Tobin*, 5 January 2010, pp. 4–6.

39 AER, *South Australian distribution determination, Final decision*, May 2010, p. 3.

40 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 37.

41 NERA, *Payout ratio of an average firm in the market: a report for Gilbert and Tobin*, 5 January 2010, p. 4.

42 If a firm became bankrupt, retained imputation credits could not be attached to cash flows and therefore the retained credits could not be distributed.

43 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, pp. 19–20.

44 AER, *South Australian Draft distribution determination, draft decision,* November 2009, p. 257 and AER, *Final decision, WACC parameters*, 1 May 2009, pp. 412, 418.

45 R. R. Officer, *Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers*, Report prepared for ETSA Utilities, 23 June 2010, p. 3.

The AER notes that it is uncertain exactly how long firms are likely to retain imputation credits. However, McKenzie and Partington noted that companies are likely to try to distribute these credits to maximise shareholder growth.[46] Furthermore, Mckenzie and Partington note that a payout ratio of 100 per cent is likely to overstate the value of undistributed franking credits, but also emphasise that it is necessary to use a payout ratio, which is greater than the actual payout ratio, to assign some value to retained imputation credits. On this basis, Mckenzie and Partington recommend an appropriate payout ratio lies between 70 and 100 per cent.[47]

The AER is not aware of any reliable empirical research on the retention period for retained imputation credits or the value of retained imputation credits for Australian companies. Handley considered that it is reasonable to assume that the exact payout ratio is likely to lie between 71 per cent and 100 per cent, however noted that there are considerable assumptions that need to be made to estimate the exact value of retained imputation credits.[48] Handley's advice noted that a 100 per cent payout ratio is consistent with the Officer WACC framework.[49] McKenzie and Partington also noted that a payout ratio of between 70 per cent and 100 per cent is appropriate.[50]

The AER agrees with the advice it received from its experts and notes the actual payout ratio is likely to be between 70 per cent and 100 per cent. However, in the WACC review, the AER did not rely on this alone to conclude that a payout ratio of 100 per cent was appropriate.

In the WACC review, the AER noted that the assumption of a 100 per cent payout ratio simplifies the framework for estimating gamma.[51] The AER considers that this remains appropriate due to the difficulty in reliably estimating the value of retained imputation credits. Consistent with the WACC review, the AER also considers that the assumption of a 100 per cent payout ratio is appropriate because:

- it is consistent with the PTRM, which assumes cash flows to perpetuity and thus the full distribution of cash flows at the end of each period
- it is consistent with the Officer WACC framework, which clearly assumes cash flows to perpetuity.

Based on all the factors discussed above, the AER considers that it remains appropriate to assume a 100 per cent payout ratio consistent with the Queensland and South Australian draft decisions and the WACC review.[52]

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46 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 26.
47 ibid., p. 27.
48 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 37.
49 ibid., pp. 32–38.
50 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 44.
51 AER, *Final decision, WACC parameters*, 1 May 2009, p. 420.
52 AER, *Final decision, WACC parameters*, 1 May 2009, p. 420; AER, *Queensland Draft distribution determination, draft decision,* November 2009, p. 207; AER, *South Australian Draft distribution determination ,draft decision,* November 2009, p. 254.

Using tax statistics to infer theta

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. Tax statistics provide a theta estimate by examining the redemption rates of imputation credits recorded by the Australian Tax Office. The AER has received information from Jemena on the values inferred from tax statistics.

Statement of regulatory intent

During the WACC review the AER concluded that the methodology used in the Handley and Maheswaran 2008 study provided a relevant and reliable estimate of theta in the post- July 2000 period.[53] The AER concluded that a reasonable range of theta estimated from tax statistics is 0.67 to 0.81 for this period. Selecting the mid-point gave a point estimate for theta derived from tax statistics of 0.74.[54]

Victorian DNSP regulatory proposal

Jemena stated that tax statistics do not provide an accurate estimate of the value of imputation credits, as the amount of credits claimed does not represent the value of those credits.[55]

Jemena submitted the Synergies report, commissioned by Energex and Ergon Energy, which provided estimates of theta (0.35) based upon tax statistics.[56]

AER considerations

The AER has previously concluded that the arguments and report presented by Jemena do not constitute persuasive evidence. Specifically, the AER has highlighted the following issues with the Synergies analysis:

- it ignores the number of imputation credits utilised by non-residents and funds
- its results are affected by double counting of imputation credits in the company tax statistics.[57]

The AER maintains that the methodology provided by the 2008 Handley and Maheswaran study provides a relevant and reliable estimate of theta in the post 2000 period. The methodology used by Synergies suffers from numerous flaws and therefore the theta estimated from this advice is unreliable.

Using dividend drop-off studies to infer theta

During the WACC review the AER considered estimates of theta derived from dividend drop off studies. It considered that a study by SFG suffered from shortcomings and instead relied on estimates of theta inferred from the Beggs and Skeels study. Since the WACC review, DNSPs have commissioned further advice from Skeels and analysis from SFG in an attempt to address the AER's concerns.

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53 AER, *Final decision, WACC parameters,* 1 May 2009, p. 455.
54 ibid., p. 455.
55 Jemena, *Regulatory proposal*, p. 178.
56 ibid., p. 178.
57 AER, *Queensland Draft distribution determination, draft decision,* November 2009, p. 212.

This section considers the DNSPs' arguments as well as further expert advice sought by the AER from Handley and Partington and Mackenzie regarding issues around dividend drop off studies.

Overall the AER considers 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 some useful information on the value of imputation credits in the Australian economy.

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:

- dividend drop-off studies are likely to suffer from multicolinearity 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 SFG dividend drop-off 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 in the SFG study
  - 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). [58]

Victorian DNSP regulatory proposal

The DNSPs have submitted a review of the SFG's 2009 dividend drop-off study, conducted by Associate Professor Skeels to support their proposals to depart from the theta estimate underlying the gamma in the SORI.[59] The Skeels report is broken up into three distinct parts:

- a comparison of the estimation outputs of the Beggs and Skeels study and the SFG study
- an examination of the AER's findings about the SFG study

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58 AER, *Final decision*, *WACC parameters*, 1 May 2009, pp. 441 and 446–447.

59 CitiPower, *Regulatory proposal*, , pp. 305–307; Jemena, *Regulatory proposal*, p. 177; Powercor, *Regulatory proposal*, pp. 312–314; SP AusNet, *Regulatory proposal*, , pp. 300–301; and United Energy, *Regulatory proposal*, pp. 152–154.

- a request for further information from SFG about the 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.

Skeels' findings were:

- after correcting for some errors identified by the AER and Skeels, Skeels argued the SFG estimate of 0.23 represented the most accurate estimate currently available
- many of the criticisms raised by the AER in the WACC review were little more than allusions to a problem and were ill-founded, other concerns needed to be examined for materiality (all of the adjustments demonstrated the error was relatively small and had little impact)
- the SFG results reported in the Skeels report allow greater comparability with the results of the Beggs and Skeels study and are much more credible than those presented in the SFG study lodged at the time of the AER's WACC review
- the SFG study extends the results from the Beggs and Skeels study from 10 May 2004 to 30 September 2006, and uses a larger and more current data set. As such, this represents an important contribution and is of equal significance as those of the Beggs and Skeels study
- due to the methodological differences between the SFG study and the Beggs and Skeels study, a compelling case can be made that the true estimate from dividend drop-off studies may lie between (0.23 and 0.57), and that in all probability it lies closer to 0.23 than 0.57.[60]

Jemena argued the SFG study is a more comprehensive study that the Beggs and Skeels study relied upon in the AER's WACC review because the SFG results are based upon a much larger cross-section of firms and a more recent data period.[61] The DNSPs consider this information to represent a material change in circumstances since the WACC review.[62]

Submissions

The AER received a submission from CitiPower and Powercor which provides further supporting information in relation to theta.[63] Attached to the submission are reports provided by ETSA Utilities in response to the draft decision for South Australian

60 CitiPower, *Regulatory proposal*, ,pp. 306–307; Jemena, *Regulatory proposal*, p. 177; Powercor, *Regulatory proposal*, pp. 313-314; SP AusNet, *Regulatory proposal*, pp. 300–301; and United Energy, *Regulatory proposal*, pp. 153–154; Skeels, *A review of the SFG dividend-drop-off study*, August 2009, p. 5.

61 Jemena, *Regulatory proposal*, p. 176.

62 CitiPower, *Regulatory proposal*, pp. 306–307; Jemena, *Regulatory proposal*, p. 177; Powercor, *Regulatory proposal*, pp. 313–314; SP AusNet, *Regulatory proposal*, pp. 300–301; and United Energy, *Regulatory proposal*, pp. 153–154.

63 Citpower/Powercor, *Regulatory proposal supporting information—theta*, Submission in support, 22 February 2010.

electricity distribution, namely those by Skeels (2010) and SFG relating to dividend drop-off studies.

Skeels concluded the concerns raised by the AER in its draft decision for South Australian electricity distribution are of either little practical importance or have been addressed by the SFG in its 2010 report.[64]

SFG concluded in its report:

- changing the tax rate for September 2001 observations from 34 to 30 per cent has an inconsequential effect on the estimate
- the best way to quantify and examine the effects of multicolinearity in the dividend drop-off setting is via a joint probability region
- the analysis shows the estimate of theta which is conditional on cash dividends being valued at 100 cents per dollar fits the data just as well as an 'unconstrained' estimate that values cash dividends at less than 100 cents and ascribes a positive value to franking credits
- there is no reason to remove special dividends and the example given by the AER about non-influential outliers does not pertain to actual market data
- after a review of 4.7 per cent of the sample and making adjustments where errors were found, the impact on the estimate has been negligible, this is in part due to the work SFG had already conducted by examining influential observations
- in response to an additional set of concerns over missing data points and other observations, SFG made further corrections to the data, these corrections have had no material effect on the outcome in the study, and
- SFG has handed over the code and data to the AER, noting the AER was able to replicate the results with this information. This is in contrast to the Beggs and Skeels, and, Handley and Maheswaran studies, neither of whom have provided the AER with the computer code or data.[65]

AER considerations

The AER has considered, in its draft determination for South Australia, that the reports by Skeels and further information provided by SFG do not represent persuasive evidence.[66] Specifically, the AER has previously considered:

- SFG's use of the Cook's D approach may be an efficient means by which to find unreliable observations but this is not a superior approach to that used by Beggs and Skeels

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64 Skeels, *A review of the SFG dividend-drop-off study,* August 2009, p. 5.

65 SFG, *Report prepared for ETSA Utilities*, 13 January 2010, pp. 1-2; and SFG, Further analysis in response to AER draft determination in relation to gamma, Report prepared for ETSA Utilities, 4 February 2010, pp. 1–2.

66 AER, *South Australian Draft distribution determination, draft decision,* November 2009, pp. 271–272.

- although the results reported by Skeels appear to address a number of the concerns identified by the AER in the WACC review, there were still a significant number of issues which demonstrated that SFG's estimates were likely to be unreliable

- the estimates from the original and revised SFG studies did not constitute persuasive evidence and the AER still considered the estimated theta from Beggs and Skeels as the most reliable estimate.[67]

The AER has reconsidered these issues in light of the advice received from Handley and Partington and Mackenzie. The AER's considerations are noted in turn below:

- the presence of multicollinearity in dividend drop-off studies

- consistency in parameter estimation

- further examination of the reliability of SFG's data set

- SFG's filtering of outliers

- other data and empirical issues.

Multicolinearity

The presence of multicolinearity in the regression model indicates that the separate effects of cash dividends and imputation credits on share price drop-off cannot accurately be determined.[68]

McKenzie and Partington advised that imputation credits are a monotonic transformation of cash dividends and therefore, theoretically there is perfect colinearity between cash dividends and imputation credits.[69] The AER notes that, as a result, multicollinearity is a significant concern for dividend drop-off studies. As noted by both McKenzie and Partington, and SFG, the only reason perfect multicollinearity does not occur in SFG’s data set is because of changes in corporate tax rates and regimes.[70]

Skeels submitted there is no evidence that multicollinearity is a concern for the Beggs and Skeels (2006) or the 2009 SFG dividend drop-off based estimates of theta.[71]

McKenzie and Partington noted that symptoms of multicollinearity in dividend drop-off studies include large standard errors and estimates of theta that are statistically insignificant.[72] Skeels also noted that symptoms of near perfect

67 ibid, pp. 271–272.
68 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 45.
69 ibid., p. 44.
70 Tax rate and regime changes over time are the only reason that cash dividends and imputation credits are not perfectly correlated in SFG’s data set. See McKenzie and Partington, *Gamma report*, 25 March 2010, p. 46 and SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 5.
71 Skeels, *Response to Australian Energy Regulator draft determination*, 13 January 2010, p. 18.
72 McKenzie and Partington, *Gamma report,* 25 March 2010, p. 45.

multicollinearity include large standard errors and insignificant coefficient estimates.[73]

McKenzie and Partington's analysis of SFG's data set shows that the coefficient of correlation between cash dividends and imputation credits is 0.70 for stock price observations after the 0.03 per cent size filter is applied. This number is 0.9899 for the 2052 observations in SFG's unfiltered data set where dividends are fully franked.[74] The AER considers that this high degree of correlation in the data indicates that SFG's results are prone to multicollinearity.

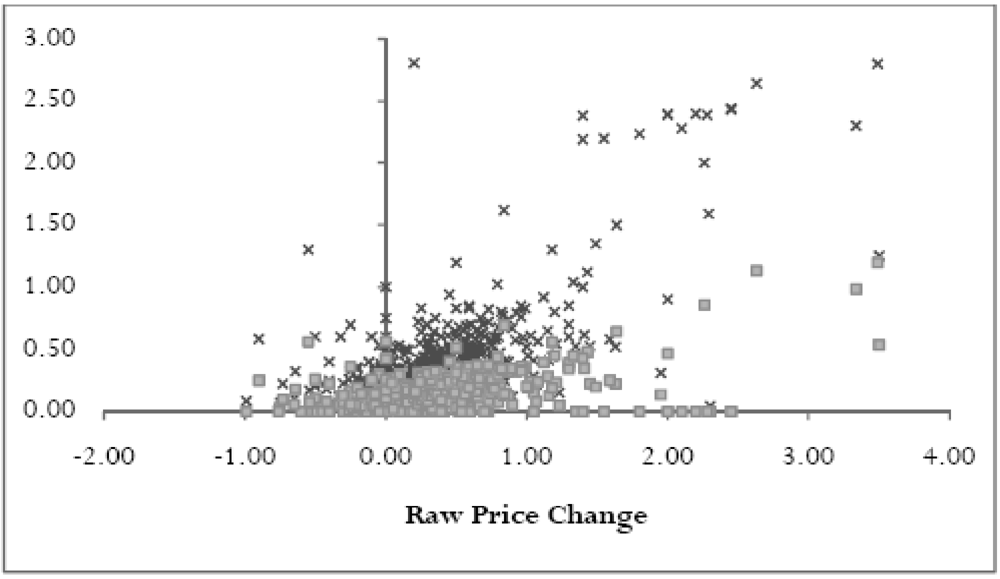
The AER notes that SFG's estimate of the value of theta in the 1 July 2000 to 10 May 2004 subsample period is not statistically different from zero. In addition to this, in the same period, SFG's estimate of the value of cash dividends is greater than one, which is economically implausible. The AER considers that this indicates the presence of multicollinearity in SFG's results.

In comparison, the Beggs and Skeels (2006) estimate of theta for the same period is statistically different from zero. In addition, their estimate of the value of a dollar of cash dividend is economically plausible and, as noted by McKenzie and Partington, is consistent with the Australian evidence from dividend drop-off studies.[75]

Skeels stated that although SFG's 1 July 2000 to 10 May 2004 estimate of theta is not statistically different from zero, the estimate of the value of cash dividends is. Skeels stated that this simply indicates that the majority of the stock price drop-off is likely to be due to the value of cash dividends and that theta is no different to zero.[76] The AER notes that McKenzie and Partington analysed the SFG data set and found that comparing raw stock price change on ex-dividend day against the cash dividend and the imputation credit shows a clustering of both to zero. However, cash dividends do exhibit a more significant positive slope than imputation credits. This is illustrated in figure 12.1.

[73] Skeels, *Response to Australian Energy Regulator draft determination*, 13 January 2010, p. 17.
[74] This is 2052 out of SFG's unfiltered sample of 5646 observations.
[75] McKenzie and Partington, *Gamma report*, 25 March 2010, pp. 30–31.
[76] Skeels, *A review of the SFG dividend drop-off study*, 28 August 2009, pp. 18–19 and Skeels, *Response to Australian Energy Regulator draft determination*, 13 January 2010, p. 18.

Figure 12.1: Raw stock price change against cash dividends and imputation credits



Note: The stock price change is graphed along the x–axis; the value of cash dividends and imputation credits paid is graphed on the y–axis.
Source: McKenzie and Partington, *Gamma report*, 25 March 2010, p. 48.

Figure 12.1 demonstrates the issue of multicollinearity, as cash dividend coefficients are estimated to be significant whilst franking credits coefficients are not significant. This highlights the issue that the values of cash dividends dominate the estimated values of franking credits and SFG's estimation technique is unable to reliably decompose the partial effect of cash dividends and franking credits on the share price drop-off around the ex-dividend day.[77]

McKenzie and Partington advised that:

> Given the inability of the estimation technique to reliably decompose the partial effect of cash dividends and franking credits due to multicolinearity, it is not surprising that the cash dividend dominates in the estimation process. [78]

The AER considers that McKenzie and Partington's analysis demonstrates that SFG's regression results are likely to be affected by multicollinearity and as a result the values of imputation credits are likely understated. Therefore, SFG's estimated values for cash dividends and theta are likely to be unreliable.

SFG submitted that their study is no more unduly influenced by multicollinearity than any other dividend drop-off study and attempted to demonstrate this through use of a joint confidence interval estimation.[79] SFG submitted a graph that shows the possible combinations of cash dividend and franking credit values that fit the market data used in its study and a comparison of the results to Beggs and Skeels original study. Based on this graph, SFG submitted that its regression estimates of the value of cash dividends and imputation credits (0.98 and 0.23 respectively) fall within the same

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[77] McKenzie and Partington, Gamma report, 25 March 2010, p. 48
[78] ibid., p. 48.
[79] SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, pp. 5–8.

joint confidence interval as the Beggs and Skeels (2006) estimates (0.80 and 0.57 respectively).[80]

The AER notes McKenzie and Partington's advice that the joint confidence interval submitted by SFG actually displays the extent to which multicollinearity affects dividend drop-off based estimates of the value of cash dividends and franking credits.[81] The AER also notes Handley's advice that the joint confidence interval analysis submitted by SFG acknowledges the imprecision in theta estimates from dividend drop-off studies.[82]

The AER considers that SFG's analysis of joint confidence intervals does not in any way address the issue of multicollinearity nor does it give any indication of which set of results for the value for imputation and cash dividends is most reliable. The AER considers that the breadth of results possible within SFG's joint confidence interval simply highlights large standard errors and the likely impact of multicollinearity on coefficient estimates from dividend drop-off studies, which was noted by the AER in both the South Australian final decision and the WACC review.[83]

Consistency in parameter estimation

SFG notes the inconsistency in the AER using an estimated value of one dollar of cash dividends at 75-80 cents in the dollar, to estimate theta, whilst applying a 100 cents in the dollar value to cash dividends, for the purpose of estimate the market risk premium and in-turn, the cost of equity. Accordingly, SFG submitted the value of a dollar of cash dividend should be set to 100 cents when estimating the value of franking credits using dividend drop-off studies because this maintains consistency with the capital asset pricing model (CAPM). SFG stated that it is appropriate to set the value of a dollar of cash dividend in this manner because the relevant and important dividend drop-off studies that examine unfranked dividends estimate the value of a cash dividend to be 100 cents. [84]

The AER notes McKenzie and Partington's advice that placing restrictions on parameters may bias the least squares estimate unless the restrictions are true.[85] To this end the AER does not consider it appropriate to set the value of a dollar of cash dividends to 100 cents in the context of estimating theta using dividend drop-off studies. As discussed above, dividend drop-off based estimates of theta are subject to considerable imprecision due to issues such as multicollinearity. For this reason, the AER considers that the independent statistical significance of the estimate of theta and the estimate for the value of cash dividends takes precedence over other considerations.

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80 ibid.p. 7.

81 McKenzie and Partington, *Gamma report*, 25 March 2010, pp. 45–47.

82 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 30–31. Handley uses the example of a set of estimates (0.72, 0.78) for the value of cash dividends and imputation credits respectively to demonstrate that SFG's joint confidence interval simply indicates the high variability in possible estimates based on the data.

83 AER, *South Australian Distribution determination, draft decision*, May 2010, p. 154; and AER, *Final decision, WACC parameters*, 1 May 2009, p. 437.

84 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, pp. 7–8.

85 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 46.

The AER also considers that in the presence of multicollinearity, setting the value of a dollar of cash dividend to 100 cents will bias the estimate of theta downwards, because unconstrained estimates provide a value for a dollar of cash dividend below 100 cents. This is illustrated in SFG's report which shows that, for each set of estimates, the higher the value of cash dividends adopted the lower the value of franking credits.[86]

SFG referred to Boyd and Jagganathan (1994) and Graham, Michaely and Roberts (2003) as 'relevant and important dividend drop-off studies' that estimate the value of a dollar of cash dividend to be 100 cents.

The AER notes Handley's advice that, contrary to SFG's view, the majority of empirical evidence from dividend drop-off studies supports a value for a dollar of cash dividend of less than 100 cents.[87] Handley further noted that:

- Boyd and Jagganathan (1994) rely substantially on arbitrage arguments (in addition to equilibrium considerations) and therefore the results of the paper should be interpreted with caution

- only a small subset (5 per cent) of stocks analysed by Graham, Michaely and Roberts (2003) provide an estimate where a dollar of cash dividends is valued at 100 cents. When the full sample of stocks is used, a dollar of cash dividend is valued at less than 100 cents.[88]

Taking account of Handley's advice the AER also considers that the majority of empirical evidence from dividend drop-off studies supports a value for a dollar of cash dividends that is less than 100 cents.

SFG also stated that estimates of theta where a dollar of cash dividend is constrained to be valued at 100 cents fall within the joint confidence interval it has constructed. The AER considers that, as discussed above, the joint confidence interval constructed by SFG cannot be used to determine whether estimates of theta and the value of cash dividends are reasonable or not.[89]

Reliability of SFG data based on Dr. John Field's methodology
ETSA Utilities submitted a report from Dr. John Field, which interrogated the SFG data set.[90] Field set out a procedure to determine the likely number of unacceptable observations in SFG's data set based on examination of a sample within SFG's data set. Field identified a sample of 150 random observations from SFG's data set of 3201 observations to be analysed for this purpose.[91] Field identified those observations

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86 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 7.
87 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 27.
88 ibid., pp. 26–28.
89 The joint confidence interval only shows that the data may produce such a result, regardless of whether the coefficients are separately statistically significant or not.
90 ETSA Utilities, *Revised regulatory proposal*, p. 193.
91 J. Field, *Reliability of data used in dividend drop-off study*, 5 January 2010, p. 5. The AER notes Field stated that he chose 150 random observation from SFG's sample of 1386 (i.e. the sub-sample for the period 1 July 2000–10 May 2004). However, it appears that the 150 observations were

where a price sensitive announcement was made to the market, two days prior and after an ex-dividend date. Such announcements will affect the price of a share around the ex-dividend day, making the share price drop-off associated with a dividend event more difficult to measure.[92]

SFG then analysed the sample of 150 random observations identified by Field from its data set of 3201 and found:[93]

- 14 observations to be excluded due to price sensitive announcements being made in relation to them
- two observations where dividends were understated.

Therefore, SFG identified 16 observations which are considered unreliable, which is an unacceptability rate of 10.7 per cent in the sample of 150 observations chosen at random. Therefore 6.2 to 16.7 per cent of observations in SFG's full data set are likely to be unacceptable according to Field's analysis.[94] This is illustrated in table 12.2, along with other examples of binomial confidence intervals provided by Field.

Table 12.2 Unacceptability rate in SFG's data set

Sample size	Number of unacceptable observations	Unacceptability rate in sample (per cent)	95% confident that unacceptability rate in whole dataset lies between:
150	16	10.7	6.2 – 16.7%
160	8	5	2.2 – 9.6%
150	3	2	0.4 – 5.7%
150	–	–	0 – 2.4%

Note: The figures above assume that there is a binomial distribution of unacceptable observations in SFG's data set.

Source: AER analysis; and J. Field, *Reliability of data used in dividend drop-off study*, 5 January 2010, pp. 3–5.

The AER notes that, rather than applying this analysis, SFG revised its estimates after excluding the 14 unreliable observations and correcting two dividends that were found to be understated, and found negligible change in its results. However, Field's analysis suggests that between 198 and 530 observations are unreliable and should be excluded from SFG's data set. This indicates a high level of unreliability within SFG's whole dataset of 3201. The AER notes that re-estimating the regression results after analysing only 150 observations does not mitigate this problem. This is

chosen at random from the total data set of 3201 for companies with a market capitalisation greater than 0.03 per cent.

92 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 16

93 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 16.

94 This is at the 95 per cent level of confidence using exact binomial confidence limits.

consistent with McKenzie and Partington's advice, which stated that auditing a random sample of observations does not serve any useful purpose.[95]

Filtering of outliers
SFG used Cook's D-statistic to identify the 1 per cent of observations in its data set that were considered unreliable and then analysed these to determine economic reliability. Based on this analysis, SFG excluded 20 influential data points that were considered unreliable.[96] SFG argued that removal of these data points improves the reliability of its results.[97]

The AER notes McKenzie and Partington's advice that the use of Cook's D-statistic may introduce a bias into SFG's analysis because it only excludes individually influential observations that are economically unreliable. This process does not identify groups of observations that are jointly significant.[98]

McKenzie and Partington also advised that identifying the most influential 1 per cent of observations was completely arbitrary and that only one of the observations in SFG's data set of 3201 had a Cook's D-statistic of greater than one, which is generally regarded as the cut-off point.[99]

The AER considers that this is important because filtered results may reflect filtering rather than the true underlying value of the parameters of interest. This is noted in McKenzie and Partington's advice.[100] McKenzie and Partington also noted that before filtering SFG's data set estimated the combined value of cash dividends and imputation credits to be between –60 and 575. After filtering the range is –60 to 55 and it appears that the filtering of outliers only affected the upper end of the distribution range.[101]

The AER notes that in comparison, Beggs and Skeels (2006) filtered data ex ante using economic criteria.[102] McKenzie and Partington advised that this is more appropriate than identifying individually influential observations and only analysing these.[103]

Based on McKenzie and Partington's advice, the AER considers that the use of Cook's D-statistic is less reliable than the methodology used by Beggs and Skeels (2006) to filter outliers and may likely bias SFG's results. Specifically, the application of the Cook's D-statistic technique arbitrarily excludes a percentage of observations and introduces bias into the results of SFG's study.

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95 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 33.
96 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 13.
97 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 13.
98 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 50.
99 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 50.
100 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 22.
101 McKenzie and Partington, *Gamma report*, 25 March 2010, pp. 22–23.
102 Beggs and Skeels (2006) identified and excluded special dividends, data where information was missing, data where the basis of quotation had changed 5 days either side of the ex–dividend day, as well as data from the volatile month of October 1987. Beggs and Skeels (2006) excluded this data based on economic justifications, see Beggs and Skeels, 'Market arbitrage of cash dividends and franking credits', *The Economic Record*, vol. 82, no. 258, p. 252.
103 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 50.

Miscellaneous data issues

The AER notes that in analysing SFG's results McKenzie and Partington found a statistically significant intercept term which was not reported by SFG.[104] This is an illogical result as it implies there is a positive value of dividends, independent of the cash dividend and imputation credit estimates. The AER notes that the combined value of cash dividends and imputation credits may therefore be underestimated by the coefficient estimates in the SFG study. In comparison, Beggs and Skeels (2006) report insignificant intercept coefficients.[105] This confirms the AER's concerns about the reliability of the SFG study.

The AER also notes that SFG's data set contains a large number of zero drop-offs, which is masked by the market adjustment.[106] McKenzie and Partington noted that in SFG's unfiltered data set, 526 out of 5646 observations are zero observations. In SFG's filtered data set, 177 out of 3201 observations are zero observations.[107] McKenzie and Partington advised that this is an abnormally high number of zero observations.[108]

The AER also notes that the combined number of negative and zero observations in SFG's filtered data set is high. McKenzie and Partington advised that almost 20 per cent of SFG's filtered data set comprise zero or negative observations.[109] The presence of a large number of zeros will depress the average drop-off ratio and bias the estimate.[110]

These data issues contribute to the AER's concerns about the reliability of the SFG study. Therefore, the AER maintains its position from the WACC review that the Beggs and Skeels (2006) study provides the most reliable estimate of theta from market prices.

McKenzie and Partington advised that a number of other data issues affect dividend drop-off studies, including:

- dividend announcements across firms tend to be clustered in time, which introduces a bias into the estimation process[111]

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104 ibid.

105 Beggs and Skeels, '*Market arbitrage of cash dividends and franking credits*', *The Economic Record*, vol. 82, no. 258, p. 243.

106 SFG adjusts all observations by aggregate movements in the all ordinaries share price index to reduce the effect of market movements on share prices around the ex-dividend date, to try and isolate the effect that a dividend payment has on a share price drop-off.

107 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 18. The AER notes that zero observations are likely to indicate that a stock is thinly traded, which would mean that they do reflect market information on how investors value either the cash dividends or the attached franking credits.

108 ibid., p. 18.

109 ibid., p. 38. The AER notes that negative observations are theoretically implausible in the context of a dividend drop-off study. Once shares go ex-dividend, they do not confer the benefit of the cash dividend or the franking credit on a purchaser. Therefore, for negative observations, it is likely that factors other than the ex-dividend event are contributing to the share price behaviour, which reduces the accuracy of dividend drop-off results.

110 ibid, p. 19.

111 ibid., pp. 23, 42.

- thinly traded stocks included in a data set may reduce the accuracy of dividend drop-off study estimates because they may not fully reflect market valuation[112]

- the bid–ask spread of stocks in a data set may affect the ability of a dividend drop-off study to extrapolate the value assigned to cash dividends and franking credits. For example, if the bid–ask spread on a stock is larger than the cash dividend this task is very difficult[113]

- price sensitive information may be released around the ex-dividend date for a stock and therefore alter the stock price to incorporate this information in addition to that reflecting the value that investors place on cash dividends and franking credits.[114]

Given these issues with dividend drop-off studies, the AER considers it appropriate to maintain the cautious approach set out in the WACC review, which uses estimates from both market prices as well as tax statistics:

> ...the results of dividend drop-off studies need to be treated with caution when inferring a theta value, given complexities involved in interpreting the results from these studies. In addition, the inherent noise in the results from dividend drop-off studies and the difficulty in separating the influence of the various components (ie. cash dividends and imputation credits) dictate that caution should be taken in interpreting the results of these studies…The question of weighting the various empirical estimates to reach a point estimate for gamma then becomes relevant. In this regard, the AER considers that for the purposes of this final decision it is reasonable to apply equal weight to each of the estimation methodologies. [115]

This is consistent with the advice of McKenzie and Partington that it is preferable to consider results from both tax statistics and market prices rather than rely on one type of study or the other.[116]

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 set 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

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112 ibid., p. 39.
113 ibid., pp. 39–42.
114 Partington and McKenzie set out the significant effect that noise may have on dividend drop-off studies by demonstrating significantly less variable stock price drop-offs where the cum-dividend and ex-dividend prices are measured no more than 1 minute. See Partington and McKenzie, *Gamma report*, 25 March 2010, pp. 15–17, 36.
115 AER, *Final decision, WACC parameters*, 1 May 2009, p. 468
116 McKenzie and Partington, *Gamma report*, 25 March 2010, p. 10.

for theta derived from tax statistics of 0.74.[117] The AER referred to the point estimate derived from tax statistics as an 'upper bound' of reasonable estimates.[118]

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.[119] The AER referred to this point estimate as a 'lower bound' of reasonable estimates.[120]

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.[121]

Victorian DNSP regulatory proposal

CitiPower, Powercor, SP AusNet and United Energy argued (assuming the payout ratio is 100 per cent) the correct lower bound for theta is 0.23, and the upper bound is 0.74. The DNSPs have then applied the WACC review's methodology to settle on a gamma of 0.5.[122]

Jemena noted in its regulatory proposal the Independent Pricing and Regulation Tribunal's (IPART) stated it was 'not convinced that there is conclusive evidence underpinning the values adopted by the AER for the payout ratio and theta' and concluded a gamma less than 0.65 was more appropriate.[123]

Submissions

The submission from CitiPower and Powercor contained a report by Skeels (prepared recently for ETSA Utilities) responding to the use of upper and lower bounds in relation to gamma.[124]

The EUCV argued the value of 0.65 accommodates the points made in the supporting documents (Associate Professor Skeels and Mr Feros) provided by the DNSPs by averaging the boundaries it identified.[125]

AER considerations

Skeels' analysis relates to the AER's comments in the WACC review in May 2009, referring to a point estimate as an upper bound. The AER has already responded to this comment in the South Australian draft decision, noting the average of two values in the Handley and Maheswaran study of 0.74 (which is not the highest value in the

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117 AER, *Final decision, WACC parameters*, 1 May 2009, p. 455.
118 ibid., p. 467.
119 ibid., pp. 446–447.
120 ibid., p. 467.
121 ibid., p. 455.
122 CitiPower, *Regulatory proposal*, pp. 306-307; Powercor, *Regulatory proposal*, pp. 313–314; SP AusNet, *Regulatory proposal*, p. 302; and United Energy, *Regulatory proposal*, pp. 156–157.
123 Jemena, *Regulatory proposal*, p. 179.
124 CitiPower/Powercor, *Regulatory proposal supporting information – theta*, Submission in support, 22 February 2010.
125 EUCV, *Submission to the AER*, 10 February 2010, p. 27.

study) should not be considered an upper bound in the statistical sense (i.e. based upon confidence intervals; which can vary depending on the probability applied). Rather, the value of 0.74 should be considered as the upper value within a range of reasonable point estimates from which the AER must determine a value based upon the regulatory framework. Further, this approach is consistent with approach taken with other WACC parameter values (e.g. gearing), where the AER examined a range of empirical point estimates and selected a value based upon the underlying criteria.

The AER notes the advice provided by Mckenzie and Partington in relation to relying on taxation and ex-dividend studies to estimate the value of gamma:

> Since the best estimation techniques are beset with problems, the most logical approach is to consider the evidence on balance across all available sources. In this respect the AER’s approach of considering both ex-dividend and taxation statistics has merit, but we would recommend a broader range of studies to triangulate the evidence considered by the AER. Relying on one study, such as that of the SFG, or one type of study, such as ex-dividend studies, would not be appropriate.[126]

Specifically, Mckenzie and Partington note that a precise estimate of gamma cannot be drawn from dividend drop-off studies due to the econometric issues (previously mentioned) and the fundamental problem of splitting the value of cash dividends and imputation credits.[127]

Regarding Jemena’s reference to IPART's recent findings, the AER notes that IPART is not bound by the same regulatory framework as the AER. It is also not apparent that IPART's review was as comprehensive or considered the same variety and depth of issues as the AER's WACC review or subsequent distribution determinations.

The AER has addressed other issues arising from the Skeels and Feros reports in previous sections, and ultimately agrees that a gamma value of 0.65 remains appropriate.

12.6.2 Estimated cost of corporate income tax

In addition to the value of gamma, a key determinant of the DNSP's tax building block is depreciation for tax purposes. Calculating the tax depreciation deduction requires an asset roll-forward calculation which uses asset values for tax purposes. As noted above, calculations for the current regulatory control period are affected by transitional rules which regard the Essential Services Commission of Victoria's (ESCV) methods and potential changes to tax legislation.

Overall, the AER considers that the DNSPs' have largely complied with the transitional rules in adopting the same tax depreciation methodology and values used by the ESCV in its last determination. Specifically, clause 11.17.2(b) of the NER requires the AER, in calculating the corporate income tax for DNSP’s, to adopt:

- The taxation values of assets carried over from the ESCV’s 2006–10 regulatory determination

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126 McKenzie and Partington, *Gamma report*, 25 March 2010, pp. 3–4.
127 ibid., p. 4.

- The classification of assets, and the method of classification, adopted by the ESCV's 2006–10 regulatory determination

- The same method of depreciation as was adopted for the ESCV's 2006–10 regulatory determination

Clause 11.17.2(c) also allows the AER to depart from methods of asset classification or depreciation methods adopted by the ESCV to the extent required by changes in the taxation law or rulings given by the Australian Taxation Office.

In the 2006–10 Electricity Distribution Price Review (EDPR), the ESCV used a diminishing value methodology to calculate tax depreciation, using the following asset categories and tax depreciation rates in table 12.2 below. Note that the 'Pre-Ralph' and 'Post Ralph' sets of categories reflect changes to the effective life of depreciating assets subject to amendments made from the Ralph review of Business Taxation, effective from 1 January 2002, requiring differential treatment of these assets.

Table 12.3 Asset classes and depreciation rates used by the ESCV

Asset Class	Rates (per cent)
Pre Ralph tax depreciation	
Land	0
6.7 to 10 years	30
10 to 13 years	25
13 to 30 years	20
> 30 years	10
Post Ralph tax deprecation	
Demand related capital expenditure	3.0
Replacement expenditure (group 1)	100.0
Replacement expenditure (group 2)	7.5
Replacement expenditure (group 3)	3.0
Environment, safety & legal	7.5
Standard metering (group 1)	37.5
Standard metering (group 2)	10.0
SCADA/Network control	7.5
Non-network general assets – IT	40.0
Non-network general assets – Other	17.7

Source: ESCV, final decision financial models.

While the DNSPs applied these categories and depreciation rates, the AER considers that recent changes to tax legislation should have been accounted for by the DNSPs under clause 11.17.2(c) when rolling forward assets for tax purposes and calculating tax depreciation for the forthcoming regulatory control period. Such changes reflect that a benchmark DNSP would comply with changes to tax law as applicable at the time, particularly where this would reduce its tax liability.

In May 2009, the Commonwealth Treasurer announced that incentives for investing in plant and equipment would be enhanced by raising the diminishing value rate from 150 to 200 per cent and applying the new rate to determine the decline in value on depreciating assets.

Amendments to Division 40 of the Income Tax Assessment Act 1997 (ITAA 1997) were made to reflect these changes to increase the deductions for the decline in value of depreciating assets. Under the new amendments where a tax payer uses the diminishing value method the tax payer is able to deduct a fixed proportion of the written-down value of an asset. For assets held on or after 10 May 2006, the proportion they are able to write off is determined by the diminishing value rate of 200 per cent and the assets effective life.[128] The new diminishing rates are set out in table 12.4.

Table 12.4 Post Ralph tax deprecation rate for assets held or after 10 May 2006

Asset Class	Rates (per cent)
Demand related capital expenditure	4
Replacement expenditure (group 1)	100
Replacement expenditure (group 2)	10
Replacement expenditure (group 3)	4.
Environment, safety & legal	10
SCADA/Network control	10
Non-network general assets – IT	40
Non-network general assets – Other	17.65

Source: ATO, AER analysis.

The AER has therefore amended the DNSPs' tax roll forward calculations to reflect this change for assets held on or after 10 May 2006. The new depreciation rates presume that DNSPs would depreciate assets faster than previously for tax purposes, resulting in a higher deduction and lower tax building block than that proposed by the DNSPs.

The AER also notes more recent changes to corporate taxation arrangements announced by the Commonwealth Government on 11 May 2010, arising out of the Henry Review.[129] Specifically, the Commonwealth Government will reduce the corporate tax rate to 29 per cent for the 2013–14 financial year and to 28 per cent from the 2014–15 financial year.[130] The AER has determined that these changes should be reflected in the expected statutory corporate income tax rate under 6.5.3 of the NER and have been applied in the AER's modelling of the DNSPs' tax building block.

12.7 AER conclusion

In accordance with clause 6.12.1 (7) of the NER, the AER's decision on the estimate cost of corporate income tax is set out below.

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128 ATO Taxation Ruling TR 2009/4, Amendment to determining the effective tax life of depreciating assets, s 40-100 of the Income Tax Assessment Act 1997 (ITAA1997), http://law.ato.gov.au/atolaw/view.htm?docid=%22TXR%2FTR20094%2FNAT%2FATO%2F00001%22#P1

129 Henry, *Australia's future tax system - Report to the Treasurer*, December 2009

130 http://www.futuretax.gov.au/pages/CuttingTheCompanyTaxRate.aspx

The AER has estimated the corporate income tax allowance for each DNSP for the forthcoming regulatory period in accordance with the formula set out in clauses 6.5.3 and 11.17.2 and other relevant provisions including clauses 6.5.4(g) and (h) of the NER.

The AER does not consider that there is persuasive evidence justifying a departure from the gamma value of 0.65 set in the SORI. The AER does not consider that the DNSPs have 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 the value of 0.65 set in the SORI inappropriate.

The AER considers that the value of 0.65 is the most appropriate estimate of gamma based on the reliable evidence currently available.

The AER's decision on the DNSPs' tax liabilities also reflects recent amendments to tax legislation affecting diminishing value rates used for tax depreciation as allowed under clause 11.17.2(c), as well as changes to the expected statutory corporate income tax rate under clause 6.5.3.

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

Table 12.5 AER conclusion on corporate income tax liability ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	6.0	6.3	6.6	6.6	6.8
Powercor	7.7	8.6	9.2	9.8	10.6
Jemena	2.3	2.8	3.3	3.7	3.0
SP AusNet	8.2	3.5	4.4	4.3	3.8
United Energy	4.8	5.6	6.7	7.2	7.8

13 Efficiency carryover amounts for 2006–10

13.1 Introduction

This chapter outlines the AER's calculations of the revenue increments or decrements for each year of the forthcoming regulatory control period of 2011–15 arising from the application of the Essential Services Commission of Victoria's (ESCV) efficiency carryover mechanism (ECM) during the current regulatory control period of 2006–10. As indicated in its decision to develop and apply an efficiency benefit sharing scheme (EBSS), the AER recognises that efficiency carryover schemes are currently operating in some jurisdictions, including Victoria. The AER will calculate and apply the carryovers in accordance with the ESCV's existing scheme in its determinations for Victorian distribution network service providers (DNSPs).

13.2 Regulatory requirements

Clause 6.4.3(a)(6) of the *National Electricity Rules* (NER) provides for a building block determination to include:

> … the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period—see paragraph (b)(6).

One of the building blocks is the carryover amounts incurred as part of the EBSS, which is defined in chapter 10 of the NER to be a scheme developed and published by the AER under clause 6.5.8. The current EBSS was published in accordance with the requirement of clause 6.5.8 of the NER in June 2008. The EBSS final decision states that:

> The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.[1]

The prevailing jurisdictional arrangements that apply to the Victorian DNSPs are detailed in the ESCV's ECM which determines the efficiency carryover amounts for the forthcoming regulatory control period.

The AER will calculate and apply the carryovers in its determinations for the Victorian DNSPs in accordance with the requirements of the NER, EBSS and the ESCV's ECM as set out in its *Electricity Distribution Price Review 2006–10* (2006 EDPR).[2]

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1 AER, *Final decision, Electricity DNSPs' EBSS,* June 2008, p. 13; AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, pp. 105–112.

2 Relevant to clause 6.12.1(9) of the NER, the AER's EBSS June 2008, and ESCV's *Electricity Distribution Price Review 2006–10, Final decision, Volume 1,* October 2006.

13.3 Summary of Victorian DNSP regulatory proposals

The efficiency carryover amounts arising from the 2006–10 regulatory control period, that have been proposed by the Victorian DNSPs to be included in the building block revenue requirements for each DNSP, are summarised in table 13.1.

Table 13.1 Victorian DNSPs' proposed efficiency carryover amount, 2011–15 ($'m, 2010)

	2011	2012	2013	2014	Total
CitiPower	–	–	–	–	**–**
Powercor	28.3	24.5	5.8	–6.0	**52.6**
Jemena	19.6	13.6	15.7	0.7	**49.6**
SP AusNet	13.8	–22.0	–5.0	2.1	**–11.1**
United Energy	9.2	6.0	–1.6	–1.4	**12.2**

Source: CitiPower, *Regulatory proposal*, table 9.2, p. 257; Powercor, *Regulatory Proposal*, table 9.1, p. 262; Jemena, *Regulatory Proposal*, table 17.1, p. 209; SP AusNet, *Regulatory Proposal*, table 9.1, p. 254; United Energy, *Regulatory Proposal*, table 10.2, p. 164.

The Victorian DNSPs proposed to carryover efficiency gains and losses consistent with the arrangements specified by the ESCV in its 2006 EDPR. However, CitiPower, Powercor, Jemena and SP AusNet proposed excluding certain costs categories from the calculation of the carryover amount on the basis that they represent:

- unforeseen and uncontrollable changes in the scale and scope of activities[3]
- cost categories that were not reflected in the ESCV benchmark allowance[4]
- costs that are associated with non-network alternatives[5]
- costs that are non-recurrent, whereas the scheme was only intended to cover recurrent costs.[6]

The Victorian DNSPs also proposed an adjustment to the benchmark allowance to reflect the assumed incremental operating and maintenance costs associated with network growth incurred over the current regulatory control period.[7]

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3 CitiPower, *Regulatory proposal 2011 to 2015*, 30 November 2009, pp. 250-254; Powercor, *Regulatory proposal 2011 to 2015*, 30 November 2009, pp. 254–259.

4 SP AusNet, *Electricity Distribution Price Review, Regulatory proposal*, November 2009, p. 261.

5 Jemena, *Regulatory proposal 2011-15*, 30 November 2009, p. 207.

6 Powercor, *Regulatory proposal*, pp. 259–260; SP AusNet, *Regulatory proposal*, p. 261.

7 CitiPower, *Regulatory proposal*, p. 250; Powercor, *Regulatory proposal*, p. 254; Jemena *Regulatory proposal*, p. 208; SP AusNet, *Regulatory proposal*, p. 264; United Energy, *Regulatory proposal*, pp. 164–165.

In addition, CitiPower and Powercor proposed adjustments to the ESCV benchmark allowance to remove the ESCV's assumed efficiency improvement of 0.39 per cent per annum. CitiPower and Powercor considered that such an efficiency adjustment is not consistent with the AER's EBSS and the requirements of clause 6.5.8(c) of the NER and section 7A(3) of the *National Electricity Law* (NEL).[8]

CitiPower also acknowledged that it had a negative carryover amount from the current regulatory control period, however, it proposed a zero carryover under the net present value (NPV) approach.[9]

Powercor submitted that it does not consider the AER can or should deduct its accrued negative carryover amount arising from the 2001–05 regulatory control period for the forthcoming regulatory control period.[10] To this end, NERA Economic Consulting (NERA) was engaged by DLA Phillips Fox, on behalf of Powercor, to review matters arising in the context of Powercor's regulatory proposal. Specifically, NERA was asked to address the issue of how the respective carryover amounts accrued under the ECM by Powercor in the 2001–05 and 2006–10 regulatory control periods should be treated in the forthcoming regulatory control period.

NERA noted that in applying the carryover amounts to the forthcoming regulatory control period to Powercor arising from the ESCV's ECM in the 2006–10 regulatory control period, it had regard to the:

- expectations engendered by the ESCV and its predecessor the Office of the Regulator-General (ORG), regarding the treatment of negative carryovers incurred in the 2001–05 regulatory control period
- manner in which the $22.9 million ($2004) accrued negative carryover was measured and the consistency of the measure with the relevant principles set out in the NEL and the NER
- effect that carrying forward the accrued negative carryover would have on Powercor's incentive to implement efficiency enhancing measures going forward and the consistency of these outcomes with the principles set out in the NEL and the NER
- carryovers accrued in relation to the 2006–10 regulatory control period and whether the measurement of carryovers under the ESCV's ECM would be consistent with the relevant principles set out in the NEL and the NER and the adjustments required to ensure consistency with these principles.

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8 CitiPower, *Regulatory proposal*, pp. 254–255; Powercor, *Regulatory proposal*, pp. 259–260; NERA Economic Consulting, *Treatment of Accrued Carryovers in the 2011-15 Regulatory Period*, December 2009, p. 21

9 CitiPower, *Regulatory proposal*, pp. 256–257.

10 Powercor, *Regulatory proposal*, pp. 263–264.

Jemena proposed an adjustment to its carryover amounts on the basis that its capitalisation policy has changed for 2008–10, as a result of the application of the new Jemena group cost allocation approach implemented in 2008.[11]

All other Victorian DNSPs stated that their capitalisation policy has not changed for the current regulatory control period.[12]

13.4 Summary of submissions

No submissions were received on this matter.

13.5 Issues and AER considerations

In assessing the Victorian DNSPs' proposed carryover amounts from the current regulatory control period, the AER has considered the following issues:

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

13.5.1 Application of efficiency carryover amounts to United Energy

United Energy proposed an efficiency carryover amount of $12 million ($2010) to be included in its building block revenue requirement.[13] This amount was calculated by comparing the benchmark allowance and the actual expenditure inclusive of related party margins.[14]

The AER notes that United Energy has experienced ‘efficiencies’, or more accurately, has benefited from lower costs during the current regulatory control period due to the loss that its related party service provider has incurred in providing operating services to it. In establishing United Energy’s forecast opex for the forthcoming regulatory control period, the AER has relied on the actual costs of United Energy’s related party service provider, Jemena Asset Management (JAM), which incorporates the loss in providing these services to United Energy. As a result, customers will not share in any of the efficiency gains United Energy has received within the regulatory control period as a result of the lower cost of services that JAM has provided to United Energy given these lower costs are not reflected in the AER's forecast opex allowance for the forthcoming regulatory control period. In other words, the AER has provided

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11 Jemena, *Regulatory Proposal*, p. 207.

12 CitiPower, *Regulatory Proposal*, p. 247; Powercor, *Regulatory Proposal*, p. 254; SP AusNet, *Regulatory Proposal*, p. 263; United Energy, *Regulatory Proposal*, p. 220.

13 United Energy, *Regulatory Proposal*, table 10.2, p. 164.

14 That is, actual expenditure refers to the contract charge, and not the actual cost to the related party.

United Energy with an opex allowance over the forthcoming regulatory control period which incorporates this loss such that United Energy's opex allowance has increased above its actual incurred costs in 2006–10. As a result, any efficiency gains received by United Energy within the 2006–10 regulatory control period were unsustainable. Given that under this approach there is no sharing of the efficiency gains with customers, which is inconsistent with the objectives of the ECM, the AER does not consider it is appropriate to determine United Energy's carryover amounts inclusive of related party margins.

In determining the carryover amounts, the AER has, where necessary, adjusted the ESCV's benchmark allowance and actual expenditure to ensure that they are compared on a like for like basis (refer to section 13.5.4). The ESCV determined United Energy's benchmark allowance exclusive of related party margins by establishing United Energy's benchmark allowance based on its actual costs prior to any related party contractual arrangements that were in place. Accordingly, the AER considers that United Energy's carryover amounts should be determined in a similar way by comparing the benchmark allowance exclusive of margins (that is, based on the actual incurred costs of the related party and not the contract charges).

The AER notes that if United Energy's carryover amount is determined exclusive of related party margins, the carryover amount is reduced to negative $50 million. The AER notes that this negative carryover amount arises because it is based on the actual costs of United Energy's related party service provider (which includes the loss in providing operating services to United Energy). However, the application of a carryover amount for United Energy excluding related party margins would result in an anomalous outcome. That is, United Energy has been receiving an efficiency gain in the form of a lower cost within the current regulatory control period as its related party provider has supplied services at a loss. However, if the carryover amount is determined excluding related party margins, this efficiency gain would register as an efficiency loss for any carryover amounts included in the forthcoming regulatory control period.

In considering this issue the AER notes that the ESCV stated in its 2006 EDPR that:

> In so far as the carryover amounts for operating and maintenance expenditure arising from the 2006-10 regulatory period and to be applied in the 2011 regulatory period are concerned, the presumption will be that, where a negative carryover amount arises, it will be applied in calculating the building blocks revenue requirement for the 2011 period. However, taking into account the prevailing regulatory arrangements at that time, future regulators should exercise discretion in determining whether this presumption should be applied to negative efficiency carryover amounts based on the circumstances that have given rise to the negative efficiency carryover amounts. [15]

This suggests that the AER should adopt the presumption that where a negative carryover arises, it will be applied in determining the DNSPs' building block revenue for 2010-15. That said, the AER has some discretion as to whether this presumption will be applied, taking into account the circumstances that have given rise to the

[15] ESCV, *EDPR 2006–10*, Volume 1, Chapter 10 Efficiency Carryover Mechanism, October 2006, p. 435.

negative efficiency carryover amounts – in this case whether to apply the negative carryover arising from the occurrence of negative related party margins.

The AER as set out above has determined a negative carryover amount for United Energy. The AER also notes as discussed above that the application of a negative carryover amount for United Energy (excluding related party margins) would result in an anomalous outcome. This outcome is considered anomalous on the basis that United Energy would receive efficiency gains within the current regulatory control period but register efficiency losses in its carryover amounts. The AER considers that this situation equates to circumstances for which applying the ESCV's presumption would not be appropriate. Accordingly, the AER has decided to use its discretion to not apply the negative carryover amounts associated with efficiencies arising from the current regulatory control period to United Energy.

13.5.2 Treatment of accrued negative carryover amounts arising from 2001–05 regulatory control period

Powercor incurred a negative carryover amount of $22.9 million ($2004) during the 2001–05 regulatory control period as part of the ECM introduced by the ORG in 2001.

Victorian DNSP regulatory proposals

Prior expectations

Powercor stated that it accrued a negative carryover amount of $22.9 million ($2004) during the 2001–05 regulatory control period that was not carried over into the current regulatory control period. Powercor stated that this was due to the ESCV adopting the 'NPV' approach with a 'zero floor'. Powercor also argued that:

> The ESCV's intention was to retain this amount for it to be 'possibly' set off against positive carryover amounts in future periods. However, the ESCV did not state that this amount would definitely be deducted in future periods. The ESCV was also clear that this accrued negative carryover amount was only intended to be used to be offset against any future positive carryover amount, and was not intended to be used to make an existing negative carryover larger.[16]

NERA, on behalf of Powercor, stated that Powercor’s expectations regarding the operation of the ECM can be inferred from statements made by both the ORG and the ESCV in their respective price reviews.[17] Specifically, NERA noted that as a result of statements contained in the ORG's 2001 EDPR, it would be reasonable for Powercor to have formed the view that:

- there was some uncertainty surrounding whether or not a future regulator’s exercise of discretion would result in negative accrued carryovers being carried forward into subsequent regulatory control periods

[16] Powercor, *Regulatory Proposal*, p. 263.
[17] NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 5.

- if an accrued negative carryover was carried forward, then consistent with the principles enunciated by the ORG, it would be subject to a zero floor and would be calculated by deducting negative carryovers from future positive carryovers.[18]

In support of this, NERA argued that:

> For negative carryovers arising as a result of the operation of the ECM, the ORG made it clear that a zero floor would be imposed and that negative carryovers would only be offset against future positive carryovers.[19]

NERA also noted that the expectations engendered by the ORG in relation to the continued operation of the zero floor were acknowledged by the ESCV in its 2006 EDPR. Further, NERA argued that statements contained in the 2006 EDPR indicated that in addition to maintaining the ORG's stated approach for the 2006–10 regulatory period, the ESCV envisaged this approach would continue in future. As observed by NERA:

> For example, at the bottom of Table 10.1 of the 2006–2010 EDPR the ESC noted that Powercor's $22.9 million accrued negative carryover could "possibly be offset against positive carryover amounts at the end of the 2006–10 regulatory period."
>
> Similarly, in its description of the NPV approach, the ESC referred to accrued negative carryovers being offset against positive carryover amounts in the 2011 period:
>
> "…where the sum of accrued efficiency carryover amounts for the 2001–05 regulatory period is negative in NPV terms, the efficiency carryover amount is set to zero for each year of the 2006–10 regulatory period. However, any accrued negative amount could be used to offset positive carryover amounts in the 2011 period."[20]

NERA considered that it would have been reasonable for Powercor to infer from the statements contained in the 2006 EDPR that the 2001–05 accrued negative carryover amount would continue to be subject to the regime in place at the time it was incurred. That is, the negative $22.9 million ($2004) would continue to be subject to a zero floor and only offset against positive carryovers.[21]

In relation to the future treatment of Powercor's 2001–05 accrued negative carryover amounts, NERA stated that:

> …the approach and expectations established by the ESC suggest that if, the AER were to decide to carry Powercor's 2001–2005 accrued negative carryover forward, then it should not retrospectively alter the manner in which it is treated by deducting that amount from Powercor's 2011–2015 revenue requirements.[22]

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[18] ibid., p. 8.
[19] ibid., p. 7.
[20] ESCV, *EDPR 2006–10*, Volume. 1, October 2006, p.424; in NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 10.
[21] NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 11.
[22] ibid., p. 11.

NERA argued that to ensure consistency with the treatment of the negative carryover in the 2006 EDPR, Powercor's 2001–05 accrued negative carryover should continue to be subject to the zero floor and offset against positive carryovers. NERA also stated that to do otherwise would undermine confidence in the regulatory regime.[23]

Inconsistency with NER and National Electricity Objectives (NEO) and measurement of efficiencies

Powercor also considered that the AER has no power to carryover amounts from the 2001–05 regulatory control period. In citing clauses 6.4.3(a)(5) and (6) of the NER, Powercor argued that:

> The intention of these provisions is to allow the AER to apply the EBSS going forward for the next regulatory control period and to also allow the AER to carry over efficiency gains or losses from the current 2006–10 regulatory control period when making its determination for the next regulatory control period. However, there is nothing in the Rules that allows the AER to apply a revenue increment or decrement based on efficiency gains or losses from a period prior to the current regulatory control period.[24]

Powercor considered that a carryover of the accrued negative amount from the 2001–05 regulatory control period:

- would be inconsistent with the NEO and the revenue and pricing principles set out in section 7A of the NEL
- would not promote any of the matters in clause 6.5.8(c) of the NER that the AER is required to have regard to when implementing the EBSS.[25]

Powercor also argued that:

> Unlike for the 2006–2010 period, it is not possible to adjust the calculation of the 2001–05 accrued carryover amount so that it is calculated in a way that accords with the approach taken in the AER's Guideline and complies with the requirements of the revenue and pricing principles and clause 6.5.8(c). The benchmarks that were established by the ORG for the 2001–05 period and against which Powercor Australia's efficiency was measured for the purposes of the efficiency carryover mechanism were not calculated in a transparent manner based on Powercor Australia's base year costs.
>
> Accordingly, the adjustments discussed in section 9.6.4 [of Powercor's regulatory proposal] cannot be made for the 2001–05 period and as a result the accrued carryover amount is not an accurate measure of Powercor Australia's efficiency for that period and deducting the accrued carryover amount in the 2011–2015 period will not promote economic efficiency.[26]

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[23] ibid.
[24] Powercor, *Regulatory Proposal*, p. 264.
[25] ibid.
[26] ibid.

NERA also argued that the processes by which Powercor's 2001–05 accrued negative carryover was calculated were inconsistent with the principles set out in clause 6.5.8 of the NER, the NEO and the revenue and pricing principles.[27]

Specifically, NERA noted that:

- in the EDPR 2006–10, the ESCV derived Powercor’s forecast opex requirements by deducting an estimate of inefficient costs
- in the EDPR 2001–05, the ORG decided not to adopt out-turn opex to establish forecast benchmarks
- in the EDPR 2001–05, the ORG did not remove the uncontrollable costs in developing the opex benchmark.

NERA noted that in the EDPR 2006–10, the ESCV derived Powercor’s forecast opex requirements by deducting $5.5 million (in $2004 terms) from actual opex in the base year (2004). This adjusted opex for 2004 was then used to determine the 2006–10 forecast opex allowance and to calculate the accrued carryover from the 2001–05 regulatory control period. As cited by NERA, ESCV explained:

> In the absence of being able to accurately identify the contributors to the increase, the Commission has made a judgement that at least $5.5m is not due to an increase in the efficient cost of providing services to Powercor’s customers. Therefore, for these reasons, an adjustment of $5.5 million has been made to Powercor’s operating and maintenance expenditure in 2004.[28]

NERA notes that the ESCV's decision to reduce Powercor’s forecast opex requirements by $5.5 million, in effect, meant that:

- Powercor bore 100 per cent of the costs of this deemed efficiency, which NERA considers inconsistent with clause 6.5.8(a) of the NER and the ESCV's 'fair sharing principle'
- Powercor's forecast opex requirements were no longer aligned with its actual opex in the base year.[29]

NERA also argued that in order to ensure consistency with the NER and the NEL, the AER should ensure that the $5.5 million ‘inefficiency’ arising from the 2001–05 regulatory control period is shared on a 30:70 basis with customers rather than being borne in full by Powercor.[30]

NERA noted that the ORG's forecast opex benchmarks for 2001–05 were developed having regard to a range of factors including historic costs, forecast costs and external benchmarks. This was done in place of developing opex benchmarks which were

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27 NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 12.
28 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 192.
29 NERA, *Treatment of accrued carryovers in the 2011-15 regulatory period*, December 2009, p. 13.
30 ibid.

aligned with out-turn opex in the final year of the 1996–2000 regulatory control period.[31]

Citing appendix C of the AER's EBSS final decision,[32] NERA considers that the decoupling of forecast and actual opex in the base year (subject to any scale or scope adjustments) can result in the scheme failing to:

- provide DNSPs with a continuous incentive to reduce opex through the regulatory period (clause 6.5.8(c)(2) of the NER)
- provide for a fair sharing of efficiency gains (losses) with users (clause 6.5.8(c)(3) of the NER).

NERA argued that these failures are also inconsistent with clause 7A(3) of the NEL and the NEO, and that in principle, these failures could be resolved by unwinding the adjustments made by the ORG to the base year actual opex (excluding any scale or scope adjustments) when it established the 2001–05 forecast opex benchmark. However, NERA also conceded that there was insufficient information available in the public domain to make such an adjustment.[33]

NERA noted that in developing opex benchmarks for the 2001–05 regulatory control period, no adjustment was made to either actual or forecast opex to remove the effect of uncontrollable costs. As such, NERA argued that the ORG's ECM scheme was inconsistent with the NEL and NER.[34]

NERA considered that the $22.9 million ($2004) accrued negative carryover estimate:

> does not simply represent the efficiency gains and losses incurred by Powercor over the 2001–2005 regulatory period. Rather, it represents a combination of changes in opex due to uncontrollable factors and efficiency gains.[35]

NERA considered that the inclusion of uncontrollable costs in the measurement of carryovers is inconsistent with the fair sharing and reward for efficiency gains principles in clauses 6.5.8(a) and 6.5.8(c)(3) of the NER, and is therefore contrary to section 7A(3) of the NEL and the NEO. NERA noted that due to the inability to distinguish between the effects of uncontrollable factors versus efficiency gains:

> little to no weight can…be placed on the $22.9 million as representing the efficiency losses incurred by Powercor over the 2001–2005 regulatory period.[36]

NERA contended that in principle, this issue could be resolved by removing the effect of uncontrollable costs from forecast and actual opex. However, NERA conceded that

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31 ibid., pp. 13–14.

32 AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008, appendix C.

33 NERA, *Treatment of accrued carryovers in the 2011-15 regulatory period*, December 2009, p. 14.

34 ibid.

35 ibid.

36 ibid.

there appears to be insufficient public information to allow the effect of these costs to be removed.[37]

Further, NERA noted that:

> the inability both to unwind the adjustment made by the ORG when establishing the 2001–2005 forecast opex benchmark and to remove the effect of uncontrollable costs, means that little to no weight can be placed on the $22.9 million estimate as representing the true value of the efficiency losses incurred by Powercor in the 2001–2005 regulatory period.

NERA also noted that carrying forward the accrued negative carryover amount and continuing to treat it in the manner established by the ORG and the ESCV would:

> violate clause 6.5.8(c)(2) of the NER and, in so doing, undermine the effectiveness of the incentives accorded to Powercor (contrary to section 7A(3) of the NEL).

NERA contended that if the AER were to carry forward the accrued negative carryover of $22.9 million ($2004) to the 2011–15 regulatory control period in the manner established by the ORG and the ESCV, it would be inconsistent with the NEO, section 7A(3) of the NEL and the principles contained in clause 6.5.8 of the NER. NERA therefore considered that the AER should employ the same transitional measure that the ORG put in place when it introduced the ECM in 2001 and set aside 2001–05 accrued negative carryover.[38]

Powercor contended that the ESCV in its 2006 EDPR did not deduct the accrued negative carryover amount based on a principle similar to the revenue and pricing principle in section 7A(2) of the NEL.[39]

Guidance from EBSS and AER Framework and Approach

Powercor argued that it does not consider the AER can or should apply this accrued negative carryover amount of $22.9 million ($2004 now $27.9 million in $2010) incurred in the 2001–05 regulatory control period when calculating the carryover amount for the forthcoming regulatory control period. Powercor argued that:

- there is nothing in the AER's EBSS that permits the carryover of this amount
- the AER's Framework and approach paper also does not signal any intention to carryover this amount[40]
- because the accrued negative carryover amount was realised in the 2001–05 regulatory control period, it is not within the scope of the AER's Framework and approach paper, which Powercor argued is expressly limited to efficiency gains or losses realised in the current 2006–10 regulatory control period.[41]

37 ibid.
38 NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 17.
39 Powercor, *Regulatory Proposal*, p. 264.
40 ibid., p. 263.
41 ibid.

In relation to the carryover amounts arising from the 2006–10 regulatory control period, NERA noted that the ESCV in its 2006 EDPR removed the zero floor for negative carryovers incurred in this period. It also observed that the AER indicated in its EBSS final decision that it intends to apply the ECM as set out in the 2006 EDPR. With regard to the manner in which the AER should treat negative carryover amounts arising under existing jurisdictional arrangements, NERA argued that:

> on the information in the AER’s EBSS Final Decision it would appear that the AER reached its decision to have recourse to the jurisdictional arrangements without specifically considering whether those arrangements would be consistent with the relevant provisions in the NEL and the NER… such an assessment should be made before finalising a decision to bring any accrued carryovers arising from the 2006–2010 regulatory period to account in the 2011–2015 regulatory period.[42]

Effect on incentives of carrying forward the accrued negative carryover

NERA argued that an accrued negative carryover amount to Powercor's revenue requirements for the forthcoming regulatory control period would severely affect the incentives Powercor has to seek out efficiency enhancements.

NERA observes that in relation to Powercor's negative $22.9 million ($2004) carryover from 2001–05, the ORG set out its view on the issues that would need to be considered by future regulators, including the factors that the ORG considered would be relevant to this determination on how to apply the negative carryover:

> ...a [no negative carryover] principle would remove the incentives on the distributors to achieve efficiency gains at the end of the regulatory period, in a situation where the business had a deferred negative carryover. Since one of the objectives of the carryover mechanism is to remove the disincentive that may otherwise exist for distributors to defer efficiency gains at the end of a regulatory period, a principle of no accrued negative carryover would not be consistent with this objective.
>
> Conversely, carrying over an accrued negative carryover in full from one regulatory period to the next may dampen incentives to achieve efficiencies in the new regulatory period, especially where the accrued carryover is significant.[43]

NERA noted that this statement suggests that the ORG envisaged that a decision on the treatment of any accrued negative carryover would involve weighing the potential for the:

- ‘no negative carryover’ principle to result in the removal of the incentive to achieve efficiency gains at the end of the regulatory control period; and the
- ‘accrued carryover’ principle to dampen the incentive to achieve efficiencies in subsequent regulatory periods.[44]

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[42] NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 18.
[43] ORG, *Electricity Distribution Price Determination 2001–05 Volume. 1 Statement of Purpose and Reasons*, pp. 89–90 (in NERA, Treatment of accrued carryovers in the 2011–15 regulatory period, December 2009, p. 8).
[44] NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 8.

Citing the ORG and the ESCV respectively, NERA noted that in the 2001 EDPR and 2006 EDPR, it was observed that an accrued negative carryover will diminish the incentive a DNSP has to seek out efficiency enhancements:

> …carrying over an accrued negative carryover in full from one regulatory period to the next may dampen incentives to achieve efficiencies in the new regulatory period, especially where the accrued carryover is significant.[45]
>
> …accrued negatives reduce the return distributors can expect to earn from 2006–10 efficiency gains. This may diminish their incentive to continue to seek out and invest in new efficiency enhancements contrary to the objectives of the mechanism.[46]

NERA also considered that this point was noted by the AER in the explanatory statement that accompanied the release of the proposed EBSS in April 2008, stating:

> the AER went on to note that if negative carryovers were to be offset against positive carryover amounts, DNSPs would no longer have a continuous incentive to reduce opex throughout the regulatory period.[47]

NERA noted that this reduction in incentives to implement efficiency enhancing measures could result in lower productive efficiencies in the network, and would translate into higher prices and sub-optimal utilisation of the services provided by the network. NERA provided an example to illustrate this 'distortion in the incentives a DNSP would face within the regulatory period.'[48]

Finally, NERA contended that even if the AER were to decide to continue to apply Powercor's accrued negative carryover from 2001–05 in the manner prescribed by the ORG and the ESCV, a decision to carry this negative carryover to the 2011–15 regulatory control period would be inconsistent with the NEO, section 7A(3) of the NEL and the principles contained in clause 6.5.8 of the NER. NERA proposed that 'with no obvious way to resolve these inconsistencies', the AER should employ the same transitional measure that the ORG put in place when it introduced the ECM in 2001 and set aside the 2001–05 accrued negative carryover.[49]

Submissions on DNSP regulatory proposals

No submissions were received on this matter.

AER considerations

Powercor accrued a negative carryover amount of $22.9 million ($2004) under the ECM in the 2001–05 regulatory control period. This amount was not carried over into the 2006–10 regulatory control period by the ESCV in its ECM at the time of its 2006 EDPR for the 2006–10 regulatory control period.[50] In effect, this negative carryover

45 ORG, *EDPR 2001–05*, pp. 89–90 (cited in NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 15).
46 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 427.
47 NERA, *Treatment of accrued carryovers in the 2011–15 regulatory period*, December 2009, p. 15.
48 ibid., pp. 15–16.
49 ibid., p. 15.
50 ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 417–418.

amount was not subtracted from Powercor's revenue requirement for the 2006–10 regulatory control period.

While this negative carryover amount of $22.9 million ($2004) was not applied to the ECM for the 2006–10 revenue determination, the AER notes that this negative amount could be offset against any potential annual efficiency gains achieved by Powercor in the current regulatory control period. As stated by the ESCV in its 2006 EDPR:

> Powercor has an accrued negative carryover amount of $22.9 million to possibly be off-set against positive carryover amounts at the end of the 2006–10 regulatory period.[51]

In considering whether the AER can apply Powercor's accrued negative carryover for the forthcoming regulatory control period, the AER's obligations under the NER are discussed below.

AER requirement to apply the EBSS and ECM

The AER determines the annual revenue requirement for a DNSP for each year of the forthcoming regulatory control period using a building block approach as described under clause 6.4.3 of the NER. One of the building blocks is the carryover amounts incurred as part of the EBSS, which is defined in chapter 10 of the NER to be a scheme developed and published by the AER under clause 6.5.8.[52] The AER published the current EBSS in accordance with the requirements of clause 6.5.8 of the NER in June 2008. The EBSS final decision included the statement:

> The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.[53]

Accordingly, the EBSS made under clause 6.5.8 of the NER requires the AER to calculate the carryover amounts in accordance with the existing ECM scheme for the 2011–15 regulatory control period.[54] The AER notes that this is the first electricity distribution determination for Victorian DNSPs since the transition to the national electricity regulatory regime. In other words, the AER must apply the ECM as set out in the 2006 EDPR in accordance with section 2.3.4 of the EBSS and AER's EBSS final decision.

The AER disagrees with Powercor's view that it has no power to carryover amounts from the previous regulatory control period.[55] The AER refers to page 435 of the ESCV's 2006 EDPR that there is a presumption that the AER will apply negative carryover amounts arising from 2006-10 regulatory period in the forthcoming regulatory control period. The AER notes that this is in accordance with the NER, the EBSS and the NEVA.

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51 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 418.
52 NER, cl. 6.5.8.
53 AER, *Electricity DNSPs EBSS*, June 2008, p. 13.
54 NER s.6.5.8–Efficiency benefit sharing scheme.
55 Powercor, *Regulatory Proposal*, p. 264

The AER notes that in accordance with the NER[56] and the National Electricity (Victoria) Act 2005 (NEVA),[57] the AER must apply the efficiency carryover mechanism (ECM) as set out in the 2006 EDPR in determining efficiency carryover amounts as part of its EBSS for the Victorian DNSPs.

The 2006 EDPR was determined by the ESCV under the authority given to the ESCV by the *Essential Services Commission Act* (ESCA)[58] and the Victorian Electricity Supply *Tariff Order* (Tariff Order).[59] The *Tariff Order* was made under s.15A of the Electricity Industry Act.[60] Specifically, clause 2.1(c) of the *Tariff Order* required the ESCV to:

- have regard to the need to provide each DNSP with incentives to operate efficiently
- ensure a fair sharing of the benefits achieved through efficiency gains between customers and the DNSP
- ensure appropriate incentives for capital expenditure and maintenance in the DNSPs' distribution systems.[61]

The result was the application of the ECM as a component of the 2006 EDPR.[62]

The AER also observes that Part 4 of the NEVA sets out arrangements for the transition from state regulation of electricity distribution services under the *Electricity Industry Act*,[63] the ESCA and the *Tariff Order*, to national regulation under the NEL and NER. Further, sections 23 and 24 of the NEVA confer the ESCV's regulatory functions, powers and duties onto the AER, and retract those duties from the ESCV. More specifically, sections 25 and 26 of the NEVA require the AER to enforce the 2006 EDPR and remove those powers from the ESCV.[64] Consequently, the AER is required by the NEVA to enforce the 2006 EDPR. The decision and reasons of the ESCV not to apply the negative carryover of $22.9 million ($2004) accrued by Powercor during the 2001–05 regulatory control period were set out in the ECM chapter of the determination,[65] and the AER is exercising existing ESCV powers applying to previous regulatory control periods.

Accordingly, contrary to Powercor's view that the AER cannot apply the carryover amounts from the 2001–05 regulatory control period, the AER notes that it is required to apply the ECM. In other words the AER must apply the ECM for this determination but the ECM will not be applied in future determinations. The AER

[56] NER cl. 6.4.3.
[57] Part 4 of the *National Electricity (Victoria) Act* 2005.
[58] *Essential Services Commission Act 2001* (Vic), ss. 32 and 33.
[59] Victorian Electricity Supply Tariff Order 2005.
[60] *Electricity Industry Act 2000 (Vic)*, s. 15A.
[61] Victorian Electricity Supply Tariff Order 2005, s. 2.1(c).
[62] ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 415–438.
[63] *Electricity Industry Act 2000* (Vic).
[64] Part 4 of the *National Electricity (Victoria) Act* 2005, s. 23,24,25,26.
[65] ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 415–438.

notes that for future determinations both positive and negative carryovers will be applied in accordance with 2.3.4 of the EBSS.

AER authority to apply the negative carryover amounts accrued in 2001–05

The AER considers that the ECM as set out in the 2006 EDPR provides the AER with the statutory authority to offset negative efficiency carryover amounts arising from the 2001–05 regulatory control period against positive carryover amounts arising from the 2006–10 regulatory control period.[66] However, the AER considers that the ECM does not provide the AER with any clear direction or authority to 'bank' those same accrued negative efficiency amounts in the event that there are no positive amounts in the 2006–10 regulatory control period to offset against.

With regard to whether it can apply the accrued negative carryover amount of $22.9 million from the 2001–05 regulatory control period, the AER notes that the ECM as set out in the 2006 EDPR:

- does not provide the AER with any explicit direction, or any discretion to set aside the negative carryover amounts from the 2001–05 regulatory control period should there not be any positive carryover amounts arising from the 2006–10 regulatory control period to be offset against
- only states that an accrued negative amount could possibly be used to offset positive carryover amounts **at the end** of the 2006–10 regulatory period[67]
- does not consider the 'banking' of accrued negative efficiency carryover amounts over consecutive regulatory control periods
- does not directly mention that the negative carryover amounts will be 'written off', where there are no positive amounts to offset against.

The AER notes that the ESCV's discussion of the ECM considers the importance of maintaining a symmetric treatment of efficiency gains and losses and also the need to provide Victorian DNSPs with incentives to pursue efficiencies.[68] Accordingly, the AER considers that it also has discretion on whether or not to set aside negative efficiency carryover amounts arising from the 2001–05 regulatory control period should there not be any positive efficiency carryover amounts to offset against in a following regulatory control period.

The AER notes that Powercor stated:

> The accrued negative carryover amount was realised in the 2001–2005 regulatory control period and is not within the scope of this [AER's Framework and Approach] statement. A decision to deduct the accrued negative carryover amount in the next regulatory control period would therefore be a departure from both the AER's Guideline and the Framework and Approach Paper.[69]

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66 ibid., pp. 418, 424.
67 ibid., pp. 418, 424.
68 ibid., p. 425.
69 Powercor, *Regulatory proposal*, p. 263.

The AER's EBSS in its final decision stated:

> The AER recognises that efficiency carryover schemes are currently operating in some jurisdictions which some DNSPs are subject to. The AER will calculate and apply the carryovers for these existing schemes in its first revenue determinations for these DNSPs in accordance with the prevailing jurisdictional arrangements in place.[70]

On this basis, the AER considers that while the primary intention of its EBSS was to set out how the AER would apply the EBSS going forward, it also recognised existing schemes such as the ECM, and stated that the AER would calculate and apply the carryovers for these existing schemes. The AER considers that the $22.9 million ($2004) negative carryover amount was incurred under the ECM scheme, and would therefore be applied in the AER's current revenue determination for the 2011–15 regulatory control period.

In terms of the prevailing jurisdictional arrangements in place, as discussed above the AER notes that it also has the statutory powers to apply the ECM as set out in the 2006 EDPR. Accordingly, the AER considers that applying the negative carryover amount of $22.9 million ($2004) incurred under the ECM for the forthcoming regulatory control period is in accordance with the NER, the AER’s EBBS final decision and the NEVA.

Prior expectations regarding the treatment of accrued negative carryovers

In response to the statements put forward by Powercor and NERA that the accrued negative carryover amount was only intended to be used to be offset against any future positive carryover amounts, the AER has reviewed the ECM set out in the 2006 EDPR.[71]

The ECM applied in the 2006 EDPR was not set out as an independent scheme under the NER; rather it was set out as part of the EDPR determination itself.[72] Chapter 10 of the 2006 EDPR sets out the ESCV’s approach to calculating and applying efficiency carryover amounts arising from the 2001–05 regulatory control period to the current regulatory control period, and those arising from the current regulatory control period to the forthcoming regulatory control period beginning 2011.

In its Framework and approach paper for the 2006 EDPR, the ESCV set out that in treating efficiency gains and losses from the 2001–05 regulatory control period, it would apply a net present value (NPV) approach with a zero floor.[73]

The ESCV also noted in the 2006 EDPR:

> Under [the zero floor approach], a negative carryover amount is not applied to the revenue requirement for the 2006–10 regulatory period where the sum of the 2001-05 carryover amounts is negative. Instead, where the sum of accrued

70 AER, *Electricity DNSPs EBSS*, p. 13.

71 NERA, *Treatment of Accrued Carryovers in the 2011–15 Regulatory Period*, December 2009, p. 11.

72 ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 415–438.

73 ESCV, *Electricity Distribution Price Review 2006 Final Framework and approach*, Volume 1, Guidance Paper, 2004, p. 69.

> efficiency carryover amounts for the 2001–05 regulatory period is negative in NPV terms, the efficiency carryover amount is set to zero for each year of the 2006–10 regulatory period. However, any accrued negative amount could be used to offset positive carryover amounts in the 2011 period.[74]

This discretion to offset accrued negative efficiency carryover amounts from the 2001–05 regulatory control period against positive carryover amounts in the 2011–15 regulatory control period is also mentioned in table 10.1 of the 2006 EDPR. The table shows that the zero floor has been applied to Powercor for the entire regulatory control period:

> Powercor has an accrued negative carryover amount of $22.9 million to possibly be off-set against positive carryover amounts at the end of the 2006–10 regulatory period.[75]

In summary, the ESCV in describing its approach in its 2006 EDPR to offsetting negative efficiency carryover amounts, noted that any remaining negative amount at the end of the regulatory control period would be accrued, and possibly used to offset positive amounts in the forthcoming regulatory control period.[76]

Accordingly, the AER considers that it is reasonable to assume that Powercor had a reasonable expectation that the negative $22.9 million ($2004) ($27.2 million in $2010 terms) would continue to be subject to a zero floor and only offset against future positive efficiencies.[77] In determining carryover amounts for Powercor, the AER has subjected the accrued negative carryover amount to a zero floor and only offset this amount against any positive carryover amounts.

Finally in response to Powercor’s view that the ESCV did not deduct the accrued negative carryover amount based on a similar principle in section 7A(2) of the NEL, it notes that the ESCV redesigned the ECM in its 2006 EDPR to apply negative carryover amounts in the 2011–15 regulatory control period. In particular, the ESCV stated that the presumption will be that, where a negative carryover arises it will be applied in calculating the building block revenue requirement for the 2011–15 regulatory control period. The AER notes that the ESCV also provided it with some limited discretion as to whether to apply a negative carryover amount. The ESCV also stated that in applying future efficiency losses:

> The Commission does not consider the financial viability of the distributors to be at material risk from this incentive mechanism. The application of the efficiency carryover mechanism only to operating and maintenance expenditure ensures that any negative efficiency carryover amounts will be calculated on an incremental basis rather than as an absolute difference between forecast and actual reported expenditure. When combined with the proposed adjustment for differences between forecast and out-turn growth, this calculation basis means the magnitude of any negative operating and

[74] ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 424.
[75] ibid., p. 418.
[76] ibid, pp. 426–27.
[77] NERA, *Treatment of Accrued Carryovers in the 2011–15 Regulatory Period*, December 2009, p.11.

> maintenance expenditure efficiency carryover amounts is unlikely to materially impact a distributor’s financial position.[78]

The AER agrees with the ESCV that the financial viability of the DNSPs is unlikely to be materially at risk through the application of the ECM. The AER agrees with NERA that there was a reasonable expectation that the zero floor approach would be applied to Powercor’s accrued negative carryover such that Powercor’s financial viability will not be at issue.

Inconsistency with NER and NEO and measurement of efficiencies

NERA on behalf Powercor considered that the measurement of Powercor's accrued negative carryover is inconsistent with the principles set out in clause 6.5.8 of the NER, the NEO and the revenue and pricing principles on the basis of the:

- ORG's decision not to use out-turn opex in the base year to establish the forecast opex benchmarks for the 2001–05 regulatory control period
- the ESCV's decision in the 2006 EDPR to deduct an estimate of 'inefficient' costs from Powercor's 2004 out-turn costs for the purposes of developing the 2006–10 opex benchmark and the 2001–05 carryover amount
- inclusion of both controllable and uncontrollable costs on the measurement of efficiency gains and losses under the ORG's ECM.

In response, the AER considers that it is not appropriate to revisit the incentive framework established by the ORG and the ESCV. The design of the scheme was established ex ante as part of the ESCV's 2006 EDPR providing carryover amounts for the 2006–10 regulatory control period. The AER notes that the ORG (and the ESCV) stated that an objective of the scheme was to enable the DNSP to seek continuous incentives to seek efficiencies such that the actual expenditure could be relied on to set efficient benchmarks for the forthcoming regulatory control period. While the AER is not in a position to gauge the impact of the incentive framework on the past behaviour of the Victorian DNSPs to seek efficiencies, the AER notes that the DNSPs received net efficiency gains (with the exception of Powercor) which were carried over into the 2006–10 regulatory control period. The AER notes that neither Powercor nor the other DNSPs raised any issues at the time of the 2006 EDPR regarding the ORG’s and ESCV's approach to:

- establishing the base year forecast for the 2001–05 opex benchmarks
- the adjustment to Powercor's base year for establishing the 2006–10 opex benchmarks
- the inclusion of uncontrollable costs in the measurement of efficiency gains and losses.

As previously noted the ESCV in its 2006 EDPR stated that any accrued negative amount could be used to offset positive carryover amounts in the 2011 period.[79] In

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[78] ESCV, *EDPR 2006–10*, Volume 1, October 2006, pp. 434–435.

response to NERA's view that the efficiencies, from which the accrued negative carryover was derived, cannot be relied upon and as such should be set aside, the AER considers that this would necessitate that the AER revisits the ESCV's ECM. However, the AER does not consider it is appropriate to set aside Powercor's accrued negative carryover on the basis that, in principle, the AER would need to revisit all of the carryover amounts received by the Victorian DNSPs in the 2006–10 regulatory control period and not only the accrued negative carryover amount for Powercor. In other words, it would not be appropriate to set aside Powercor's accrued negative carryover, unless the net efficiency gains arising from the 2001–05 regulatory control period and included in the building block revenue for 2006–10 by the ESCV for the other DNSPs were also set aside.

The AER also notes that the sharing of efficiency gains and losses with customers was also established by the design of the ECM. In principle, the AER does not consider it appropriate to revisit the design of the scheme given that incentives are determined on an ex ante basis and the AER cannot influence past behaviour. The AER also notes that the ORG considered that the scheme provided a fair sharing of efficiency gains and losses. The ORG stated that:

> …..the Office [ORG] has had regard to the requirement on the Tariff Order to ensure a fair sharing of benefits between customers and consumers.[80]

Accordingly, the ORG and the ESCV were required to have regard to ensuring a fair sharing of gains and losses between the DNSPs and customers under the *Tariff Order*.[81]

The AER considers that as the requirements of the *Tariff Order* and the NER are similar, the AER does not accept NERA's view that the ORG's approach to establishing the benchmark allowances for the 2001–05 regulatory control period was inconsistent with clauses 6.5.8(c)(2) and 6.5.8(c)(3) of the NER, the NEO and the revenue and pricing principles in the NEL. The AER also notes that Powercor and NERA consider that the NER and the NEO should be applied retrospectively to the ESCV's ECM. The AER, as discussed above, notes that the AER's final EBSS decision requires that the AER apply the prevailing jurisdictional arrangements, in this case the ESCV's ECM.

Accordingly, the AER does not consider it appropriate to reconsider the calculation or to set aside the accrued negative carryover amount on the basis that:

- the appropriate time to consider these issues would have been at the time of the 2006 EDPR, noting that Powercor and the other DNSPs did not raise these issues as part of the ESCVs 2006 EDPR

- any revisiting of the accrued negative calculation or the setting aside of the accrued negative carryover amount also requires that all the efficiency amounts

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79 ESCV (2006) Electricity Distribution Price Review 2006-10 October 2005 Price Determination as amended in accordance with the decision of the Appeal Panel dated 17 February 2006 Final Decision Volume 1, p.424

80 ORG, *EDPR, 2001–05,* Vol.1, p. 86.

81 Victorian Electricity Supply Tariff Order 2005.

(derived in the same regulatory control period as the accrued negative amount) received by the DNSP be revisited, however, the AER does not have any discretion to revisit any positive carryover amounts from prior regulatory control periods

- the ORG and ESCV were required to have regard to a fair sharing of efficiency benefits in establishing their ECM.

Powercor and NERA also argued that the $22.9 million ($2004) accrued negative carryover did not simply represent the efficiency gains and losses incurred by Powercor over the 2001–05 regulatory control period. Rather it represents a combination of changes in opex due to uncontrollable factors and efficiency gains.

In establishing the ECM, the ORG and the ESCV did not design the ECM such that uncontrollable costs should be identified and excluded from the carryover amounts. The AER notes that the ESCV has previously recognised that the efficiency carryover amounts may include both management induced efficiency and windfall gains and losses.

> As the Office [ORG] noted in its *Draft Decision*, an audit of the actual efficiency gains within a regulatory control period would necessitate a forensic assessment and would be extremely difficult and costly. Such a forensic analysis would be subject to many of the criticisms made by the distributors and other parties in response to the Office's earlier proposals to distinguish between management–induced and windfall efficiency gains.[82]

However, given the difficulties of separately identifying management (in) efficiencies from windfall gains and losses, no attempt was made to distinguish the two. Most importantly, the DNSPs' carryover calculation may have included some 'efficiency gains' that may not have been the result of management effort. The AER further notes that Powercor did not favour distinguishing between uncontrollable (windfall gains) and controllable costs (management induced efficiencies) on the grounds that such an approach would involve significant regulatory risks, administrative and compliance costs and lessen and distort incentives for efficient behaviour.[83] However, as discussed previously, the AER does not consider it appropriate to make ex post adjustments to the carryover amounts.

NERA noted that the forecast opex benchmarks in the 2006 EDPR applied a 0.39 per cent per annum improvement in partial factor productivity.[84] As a result it is noted that an efficiency gain would only accrue where a DNSP has been able to achieve an efficiency gain in excess of 0.39 per cent per annum. NERA considered that the inclusion of this productivity factor in the forecast opex benchmark means that:

- contrary to the reward (penalty) for efficiency gains (losses) principle set out in clause 6.5.8(c)(3) of the NER, DNSPs that achieve an efficiency gain that is less

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82 ORG, *EDPR 2001–05 Volume 1*, p. 86.

83 Powercor, *Efficiency Measurement and Benefit Sharing – Submission to the Office of the Regulator–General's 2001 Electricity Distribution Price Review*, February 1999, pp. 9–11.

84 NERA, *Treatment of Accrued Carryovers in the 2011–15 Regulatory Period*, December 2009, p. 19.

than the 0.39 per cent per annum benchmark will be penalised, notwithstanding the fact that they have made an efficiency gain.

- contrary to the fair sharing principle in clause 6.5.8(c) of the NER, the efficiency gains and losses will not be shared fairly between the users and the DNSPs. In this context allowing the DNSPs to capture less than 30 per cent of the efficiency gains and bearing more than 30 per cent of the efficiency loss is contrary to the ESCV's own fair sharing principle, which was based on the same 30:70 ratio that underpins the EBSS.[85]

In respect of the ESCV's application of its 0.39 per cent per annum partial productivity factor, the ORG and the ESCV in developing their ECM were required to have regard to providing a fair sharing of efficiency benefits between Victorian DNSPs and customers. In addition, the AER notes that as it cannot influence past behaviour it is not appropriate to review the ECM. The AER notes that where the 0.39 per cent productivity factor resulted in a lower efficiency gain for Powercor than would be the case in the absence of this factor, the AER has no discretion to not apply the ECM.

Effect on incentives of carrying forward the accrued negative carryover

The AER notes that the ORG and the ESCV previously considered the effect on incentives associated with accrued negative carryover amounts between regulatory control periods.

The AER agrees with NERA that the retention of an accrued carryover amount that is not applied to the building block revenue for the 2011–15 regulatory control period such that this negative amount would need to be offset against future positive amounts (that is, the 2016–20 regulatory control period) would dampen the incentive for Powercor to seek future efficiencies.

The AER notes that for the 2006 EDPR, the ESCV made a number of changes to the ORG's ECM for the 2001 EDPR. Instead of applying the ORG's approach of offsetting negatives against future positives (that is, referred to as the 'forward only' approach by the ESCV), the ESCV adopted the 'net present value (NPV) approach'. Under this NPV approach, negative carryovers were offset against positive carryovers, irrespective of when they occurred in the 2001–05 regulatory control period. As explained by the ESCV:

> Where negative amounts are offset against positive amounts, irrespective of when they occur within the regulatory period, the negative amounts would be offset against the positive amount of the first year, until the positive amount was eliminated and zero was recorded for each year…At the end of the regulatory period, any remaining negative amount would be accrued and possibly used to offset positive amounts in the next regulatory period.[86]

Under the ESCV's zero floor NPV approach, the 2001–05 accrued carryover for each DNSP was calculated as follows:

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[85] NERA, *Treatment of Accrued Carryovers in the 2011–15 Regulatory Period*, December 2009, p. 13.

[86] ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 426.

Accrued $\text{Carryforward}_{2001\text{-}2005}$=

$$\text{Max}[(\sum_{2001}^{2005} \text{PV positive carryover amounts} - \sum_{2001}^{2005} \text{PV negative carryover amounts}),0]$$

The AER also notes that in contrast to the NPV approach, the ESCV also considered a 'forward only' approach:

> Where negative amounts are only offset against future positive amounts that occur within the remainder of the regulatory period, the positive amount from the first year of the regulatory period would not be offset against the negative amounts occurring later in the period. This would result in the distributor carrying the full positive amount over into the next period despite the subsequent efficiency losses. The negative amounts arising in the later years of the period would be set to zero, although the accrued negative would still exist at the end of the regulatory period and could possibly be used to offset positive amounts in the subsequent regulatory period. This would provide a reward for initial efficiency gains with no clear consequences for subsequent efficiency losses, removing the even incentive intended by the mechanism. It would also result in customers paying for the distributors to be rewarded for efficiencies that are not sustainable.
>
> This approach would protect distributors against the negative efficiency consequences of 'ramping-up' expenditure in the last years of the regulatory period in order to achieve higher expenditure allowances for the next regulatory period. This is presented in Table 10.3 as the "Forward Only" approach.[87]

Table 10.3 in the 2006 EDPR shows the efficiency carryover amounts that would apply to the Victorian DNSPs for inclusion in the 2006–10 revenue requirements under the two approaches.[88] The AER recognises that the table also shows the value of any carryover amounts that could not be offset against any positive amounts (that is, accrued negative amounts) that would remain at the end of the 2006–10 regulatory control period to be offset against any future positive carryover amounts in the 2011–15 regulatory control period.

The AER notes that in its 2006 EDPR, the ESCV stated that it was preferable that the NPV approach be applied, to ensure that any accrued negative amount at the end of the 2001–05 regulatory control period is calculated net of any positive amounts.[89]

The AER also notes that the NPV was used specifically for the 2006–10 regulatory control period, and specifically applied so that it would result in no accrued negative amount for four of the five Victorian DNSPs. As stated by the ESCV:

> This ensures efficiency incentives are maintained in the 2006–10 regulatory period and better contains the impact of the 2001–05 efficiency carryover mechanism within the 2006–10 regulatory period as intended by the ORG (2000a, p. 90) when it adopted the 5 year carryover period.[90]

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[87] ibid.
[88] ibid.
[89] ibid., p. 427.
[90] ibid.

While the ESCV preferred to use this method for the EDPR 2006–10, the AER considers that this does not bind the AER to use the NPV method for its current determination.

The AER considers that if it were to adopt either the NPV with zero floor approach, or the forward only approach, Powercor's negative carryover from 2001–05 would be fully offset against positive efficiencies incurred in 2006–10. Given that Powercor's accrued negative amount has been fully offset against positive efficiencies under either the NPV or the forward only approach, Powercor’s incentives to seek future efficiencies will no longer be an issue for consideration by the AER.

13.5.3 Ex post adjustments to the benchmark allowance associated with network growth

In its 2006 EDPR, the ESCV proposed the establishment of a method for adjusting the expenditure benchmarks for differences between actual and forecast demand growth when calculating the efficiency carryover amounts for the forthcoming regulatory control period.[91]

The ESCV in its 2006 EDPR subsequently outlined the growth adjustment it considered to be appropriate to apply to the expenditure forecasts and the future calculation of the ECM. The ESCV's growth adjustment methodology is reproduced below:

> Growth adjustment = PFP coefficient weightings x % change in growth
>
> = 0.431(log natural change in customers) + 0.272 (log natural change in peak
>
> demand) + 0.296(log natural change in consumption)
>
> Where:
>
> 0.431 is the PFP coefficient weighting associated with customer numbers
>
> 0.272 is the PFP coefficient weighting associated with peak demand
>
> 0.296 is the PFP coefficient weighting associated with consumption.[92]

The ESCV in outlining the growth adjustments relevant to the future calculation of the carryover amounts stated that:

> In considering this growth adjustment coefficient for use in the calculation of future efficiency carryover amounts, the Commission is cognisant of the fact that the future necessarily involves uncertainty and that it is neither prudent nor possible to make permanent now the future application of this aspect of the efficiency carryover mechanism. This coefficient therefore represents a guide to inform future debate and decisions on this issue and give greater certainty as to the merit assessment made during this review.[93]

91 ibid., p.82.
92 ibid., pp. 435–436.
93 ibid., p.436.

Victorian DNSPs regulatory proposals

The Victorian DNSPs proposed to apply growth adjustments to the ESCV benchmark 2006–10 allowances. The impacts of proposed growth on the benchmark allowances for the Victorian DNSPs are set out in table 13.2.

Table 13.2 Impact on annual benchmark opex from Victorian DNSPs' proposed growth adjustments, 2006–10 ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower	–0.28	–0.28	–0.28	–0.28	–0.28
Powercor	0.64	0.64	0.64	0.64	0.64
Jemena	0.06	–0.06	–0.04	–0.04	–0.05
SP AusNet	1.39	1.41	2.41	3.41	0.00
United Energy	0.23	0.46	0.70	0.93	1.16

Source: CitiPower, *Regulatory proposal*, attachment C0062 Efficiency carryover model; Powercor, *Regulatory Proposal*, attachment C0062 Efficiency carryover model; Jemena, *Regulatory Proposal*, appendix 13 JEN forecast data model - efficiency carryover sheet; SP AusNet, *Regulatory Proposal*, SPA post-tax revenue model, efficiency carryover sheet; United Energy, *Regulatory Proposal*, appendix B-3 ECM.

Submissions on DNSP regulatory proposals

No submissions were received on the efficiency carryover mechanism.

AER considerations

All Victorian DNSPs stated that they applied a growth adjustment to the ECM using the growth adjustment method determined by the ESCV over the 2006–10 regulatory control period.[94] The ESCV stated in its 2006 EDPR that:

> In considering this growth adjustment coefficient for use in the calculation of future efficiency carryover amounts, the Commission is cognisant of the fact that the future necessarily involves uncertainty and that it is neither prudent nor possible to make permanent now the future application of this aspect of the efficiency carryover mechanism. This coefficient therefore represents a guide to inform future debate and decisions on this issue and give greater certainty as to the merit assessment made during this review.[95]

The AER considers that while the ESCV did not commit to applying this method for the calculation of future carryover amounts, it considers that it would have been reasonable for the Victorian DNSPs to expect that this approach would be applied to carryover amounts for the 2011–15 regulatory control period. In particular, the AER notes that the ESCV stated that establishing a method for future growth adjustments provides greater certainty to the Victorian DNSPs and other stakeholders on the

94 CitiPower, *Regulatory proposal*, p. 250; Powercor, *Regulatory proposal*, p. 254; Jemena *Regulatory proposal*, p. 208; SP AusNet, *Regulatory proposal*, p. 264; United Energy, *Regulatory proposal*, pp. 164–165.

95 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 436.

calculation of the efficiency carryover amounts in the 2011–15 regulatory control period.[96] Accordingly, the AER has applied the growth adjustment formula specified by the ESCV in its 2006 EDPR (and restated in section 13.5.3) to calculate the carryover amounts for the 2011–15 regulatory control period. That said, while United Energy and Jemena have proposed this growth adjustment as part of the EBSS for the forthcoming regulatory control period, the AER has applied the growth adjustment detailed in the opex chapter of this draft decision.

The AER has reviewed the growth adjustment proposed by the Victorian DNSPs and has identified some inconsistencies with the growth adjustments as specified by the ESCV in its 2006 EDPR. In particular, all Victorian DNSPs applied an incorrect growth averaging formula as the impact of growth was not compounded for each year of the current regulatory control period. In addition, Jemena only proposed an adjustment for customer numbers and no adjustment was made in relation to energy consumption and peak demand. Jemena advised that this was an error and accepted that all three inputs should be included in the calculation of the ECM.[97] The AER will update the growth adjustment calculation based on actual customer numbers, energy and peak demand for 2009 in its final determination to determine the carryover amounts for the Victorian DNSPs.

The AER has corrected these errors and omissions and this has resulted in minor adjustments to the ECM calculations for each Victorian DNSP.

AER conclusions

The AER has made corrections to the growth adjustments proposed by the Victorian DNSPs to the ESCV benchmark allowances consistent with the 2006 EDPR. The impacts of revised growth on the benchmark allowances for the Victorian DNSPs are set out in table 13.3. The AER will update the growth adjustments to the ECM using the 2009 actual customer numbers, energy consumption and peak demand for the final determination.

Table 13.3 AER conclusion on impact of growth on annual benchmark opex, 2006–10 ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower	–0.28	–0.57	–0.85	–1.12	–1.40
Powercor	0.34	0.67	1.01	1.35	1.69
Jemena	0.02	0.04	0.07	0.09	0.11
SP AusNet	–0.12	–0.25	–0.37	–0.49	–0.61
United Energy	0.12	0.24	0.35	0.47	0.59

Source: AER analysis.

96 ibid.

97 Jemena, *Response to AER information request*, 23 February 2010.

13.5.4 Consistency in the measurement of actual expenditure with the ESCV benchmark allowance

The ESCV [98]stated that for the rewards implicit in the ECM to reflect the cost of providing the distribution services, it is important that the reported expenditure information is calculated on the same basis as the expenditure forecasts against which it is compared. The AER also notes that in its 2006 EDPR the ESCV identified a number of adjustments that it considered to be necessary to ensure a 'like for like' comparison between the benchmark allowance and actual expenditure in calculating the efficiency carryover amounts for 2006–10. These adjustments were restricted to:

- growth adjustments
- capitalisation of overheads
- movements in non cash costs (that is, provisions).[99]

The AER also notes that the ESCV excluded related party margins (referred to as contractual arrangements) from the Victorian DNSPs' forecast opex allowance.[100] As a result, the AER has assessed the carryover amounts on the basis that actual expenditure is exclusive of related party margins. In addition, the AER has also made adjustments to the carryover amounts for licence fees and the reclassification of some costs for CitiPower and Powercor associated with its advanced metering infrastructure.

Accordingly, the AER has reviewed the Victorian DNSPs' proposed carryover amounts and where necessary has adjusted the original ESCV benchmark allowance and the DNSPs' actual expenditure to ensure a 'like for like' comparison for the factors identified above. The AER has not applied any adjustments to United Energy given that it has decided to not apply the ECM to United Energy (refer to section 13.5.1).

Capitalisation of overheads

In its 2006 EDPR, the ESCV specifically stated that:

> To measure efficiencies arising from the 2001–05 regulatory period, the Commission has considered the capitalisation policies of the distributors when comparing them with those underpinning the benchmarks during the 2001–05 period to ensure they are measured on a like basis. This may be required again if policies for capitalising overheads change in the 2006–10 regulatory period relative to those assumed in developing the 2006–10 expenditure forecasts.[101]

The AER has reviewed the basis of the ESCV's method of determining the benchmark allowance for Powercor, CitiPower and Jemena. The AER notes that for SP AusNet and United Energy the ESCV benchmark allowance assumed that 100 per cent of

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[98] ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 419.

[99] ibid.,, pp. 167-168. The AER notes that the ESCV in its 2006 EDPR also reallocated costs between services during the regulatory control period.

[100] ibid.,, table 5.7, pp. 192-193.

[101] ibid., p. 433.

indirect corporate overheads are expensed (i.e. not capitalised) as operating expenditure over the 2006–10 regulatory control period.[102] In contrast, for CitiPower, Powercor and Jemena, the ESCV 'rolled forward' the proportion of actual indirect overheads capitalised in 2004 subject to some adjustments.[103]

Victorian DNSP regulatory proposals

Jemena has stated that its capitalisation policy has changed for 2008–10.[104] Jemena stated that the change in its capitalisation policy is a result of the application of a new approach to the allocation of costs across the Jemena group implemented in 2008 and Jemena has adjusted for this change in policy in applying the ECM.[105]

CitiPower, Powercor, SP AusNet and United Energy stated that their capitalisation policy has not changed for the current regulatory control period.[106]

Submissions on DNSP regulatory proposals

No submissions were received on the Victorian DNSPs' capitalisation policies.

AER considerations

Capitalisation of indirect (corporate) overheads

Jemena has stated that its proposed adjustments to the benchmark allowance for 2008 and 2009 are related to the impact of change in overhead allocation methodology. Jemena has also stated that this change in methodology results in the reduction of $4.34 million ($2010) of capitalised indirect overheads for each year over 2008–10.[107] The AER has reviewed Jemena's reported costs and notes a reduction of the amount of indirect overheads that is capitalised, which is consistent with Jemena's proposed reduction in capitalised indirect overheads.

The AER requested that Jemena provide its calculation used to adjust its carryover amounts for its change in capitalisation policy.[108] However, in response Jemena has not provided any details to enable the AER to verify this calculation. In addition, the AER has reviewed the allocation of corporate costs allocated to Jemena within the Jemena group and for the draft decision has amended this allocation (refer to chapter 6). This amendment has resulted in a reduction in the amount of corporate costs allocated to Jemena. While the AER's amendments to the allocation of Jemena group costs to Jemena may impact on the amount of capitalised overheads, the AER has not further adjusted Jemena's carryover amount as Jemena has not provided any information to substantiate its proposed $4.34 million ($2010) reduction to indirect overheads (corporate).

[102] ibid.,, pp. 274–275.
[103] ibid., table 7.12, p. 275.
[104] Jemena, *Regulatory proposal*, p. 207.
[105] ibid.
[106] CitiPower, *Regulatory proposal*, p. 247; Powercor, *Regulatory proposal*, p. 254; SP AusNet, *Regulatory proposal*, p. 263; United Energy, *Regulatory proposal*, p. 220.
[107] Jemena, *Response to AER information request*, 23 February 2010; Jemena, *Response to AER information request*, 16 March 2010
[108] ibid.

The AER has only included Jemena's proposed reduction in capitalised indirect overheads of $4.34 million ($2010) as a placeholder in the draft decision as Jemena has not substantiated its proposed adjustment of $4.34 million for 2008. The AER also notes that the reduction of the amount of corporate indirect overheads of $4.34 million for 2009 is an estimate and will need to be updated based on 2009 reported expenditure. The AER will require Jemena to provide sufficient details for the final decision to enable this calculation to be verified and to consider any further adjustments that may be necessary due to the reallocation of Jemena group corporate costs to Jemena. The AER will also review Jemena's regulatory accounts for 2009 in its final decision regarding any changes to capitalisation of indirect overheads.

The ESCV[109] stated in its 2006 EDPR that all of SP AusNet's indirect overheads would be treated as operating expenditure (that is, there would be no capitalisation of indirect (corporate) overheads for the 2006–10 regulatory control period). SP AusNet has stated to the AER that there has been no change in its capitalisation policy in the current regulatory control period.[110] The AER has reviewed SP AusNet's capitalisation policy which indicates that SP AusNet does capitalise some of its indirect (corporate) overheads.[111] The AER notes that SP AusNet has subsequently capitalised around $108.8 million ($2010) of indirect overheads over the current regulatory control period. In contrast as noted above the ESCV benchmark allowance assumed that all indirect overheads will be expensed (i.e. there would be no capitalisation of indirect overheads).[112] In addition, the AER notes that SP AusNet has excluded the amount of indirect capitalised overheads in its regulatory proposal associated with new connection and augmentation services.[113]

SP AusNet has confirmed that it has capitalised both direct and indirect corporate overheads for the current regulatory control period. That is, the amount of 'indirect overheads' reported by SP AusNet includes both direct and indirect overheads.[114] SP AusNet has also advised that it is not able to identify the amount of direct and indirect overheads that have been capitalised over the 2006–10 regulatory control period.[115] In the absence of information from SP AusNet, the AER has assumed that 50 per cent of the total amount of 'indirect overheads' reported over the 2006–10 regulatory control period is attributable to indirect overheads. This adjustment is necessary to ensure a ‘like for like’ comparison between actual operating and maintenance expenditure and the ESCV benchmark allowance.[116] The AER's adjustment to SP AusNet's capitalised overheads to calculate its carryover amounts for the forthcoming regulatory control period is provided in table 13.4. The AER will

109 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 274.
110 SP AusNet, *Regulatory proposal*, p. 263.
111 SP AusNet Regulatory Accounts, 2006–2009; SP AusNet, *Regulatory proposal*, p. 174. While it is not clear whether SP AusNet has changed its capitalisation policy, the ESCV benchmark allowance will need to be adjusted for the amount of capitalised indirect (corporate) to ensure like for like comparability between actual expenditure and the benchmark allowance. The AER also notes that SP AusNet in its proposal also stated that its capitalisation rate is expected to change from the historical average of 26.5 per cent for the period 2006–2009 to a reduced overhead capitalisation rate of 16 per cent for the forthcoming regulatory control period
112 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 274.
113 The AER notes this data is included in the regulatory information notice templates.
114 SP AusNet, *Response to AER information request*, 30 March 2010.
115 ibid.
116 The AER notes the total amount capitalised in the RIN is consistent with the regulatory accounts.

review SP AusNet's regulatory accounts for 2009 in its final decision regarding any changes to capitalisation of indirect overheads.

Powercor stated in its regulatory proposal that it has not changed it capitalisation policy. Powercor also stated that only a portion of its indirect overheads are being capitalised.[117] However, the AER notes that Powercor appears to be capitalising all of its indirect overheads.[118] The AER sought further clarification and Powercor stated that DNSPs interpret corporate costs and indirect cost to have different meanings.[119] Powercor stated further that indirect costs are those costs which have been transferred to capital or maintenance expenditure as they have been recognised in the statutory accounts as supporting the construction and maintenance of assets.[120] CitiPower has also stated in its proposal that it has not changed its capitalisation policy.

The AER notes that both CitiPower and Powercor's capital expenditure has increased more than the operating and maintenance expenditure during the current regulatory control period of 2006–10.[121] The AER also notes that, for the current regulatory control period, the level of capitalisation has increased for CitiPower and Powercor.[122] The AER expects that more indirect overheads would be capitalised during the current regulatory control period as more overheads are likely to be required to service the increased capex incurred by Citipower and Powercor above its 2004 levels. Accordingly, the AER has accepted that CitiPower and Powercor's capitalisation policy has not changed over for the period 2006–08. The AER will review Powercor and CitiPower's regulatory accounts for 2009 in its final decision regarding any changes to capitalisation of indirect overheads.

AER conclusion

The AER will review the Victorian DNSPs' regulatory accounts for 2009 in its final decision regarding any changes to capitalisation of indirect overheads. The AER requires Jemena to substantiate its proposed adjustment of $4.34 million in 2008 and 2009 as a result of the change in its capitalisation policy. The AER has adjusted the original ESCV benchmark allowances for SP AusNet to ensure that the actual expenditure and the ESCV benchmark allowances are considered on a 'like for like' basis in measuring the carryover amounts for the 2006–10 regulatory control period. The AER has accepted CitiPower and Powercor's capitalisation policy has not changed over for the period 2006–08.

Movement in provisions

The ESCV benchmark allowances do not include the movement in provisions.[123] In its 2006 EDPR the ESCV removed any movements in provisions to reported expenditure on the basis that movements in provisions:

[117] Powercor, *Regulatory proposal*, p. 251.
[118] Powercor RIN template 3.4 – O & M table 1.
[119] Powercor, *Response to AER information request*, 2 March 2010.
[120] ibid.
[121] AER's analysis.
[122] AER's analysis.
[123] Provisions include contingent liabilities such as employee entitlements, environmental obligations, safety obligations, doubtful debts and obsolete stock.

- may be used to represent the reported accounts of the DNSPs differently from their underlying economic circumstances
- may prevent and distort the comparison of DNSPs on a consistent basis from year to year and across DNSPs
- if the ESCV were to factor provisions into the forecast of expenditure, compensating adjustments to the RAB will be very complicated
- may also advantage one DNSP over another
- can be affected by a change in accounting standards despite expenditure remaining the same. [124]

Given the ESCV benchmark allowance excludes the movement in provisions the AER has also excluded the movement in provisions to ensure a 'like for like' comparison of actual expenditure and the benchmark allowance for 2006–10. The AER has also excluded any movement in provisions for the purpose of determining the base year level of operating and maintenance expenditure in chapter 7 of this decision.

With the exception of CitiPower and Powercor, the Victorian DNSPs did not propose to remove the impact of the movement in provisions in the carryover amounts. CitiPower and Powercor proposed to remove the impact of provisions (both positive and negative) from their actual expenditure to calculate the carryover amounts. The AER has reviewed these proposed provision adjustments for consistency with both CitiPower's and Powercor's regulatory accounts for 2006–08. The AER has adjusted for some minor differences between the movement in provisions reported in Powercor's regulatory accounts and its regulatory proposal. The AER has also adjusted SP AusNet's movement in provisions for an assumed allocation of costs between its gas and electricity businesses. The AER for its final decision requires SP AusNet to provide further information to enable the movement in provisions for the assumed allocation between its gas and electricity businesses to be verified. The AER has also adjusted Jemena's expenditure for miscellaneous provisions to ensure a 'like for like' comparison of actual expenditure and the benchmark allowance for 2006–10.

AER conclusion

The AER has made minor amendments to CitiPower and Powercor's reported expenditure for the movement in provisions for 2006–09. The AER will review CitiPower's, Powercor's, Jemena's and SP AusNet's reported expenditure for 2009 and if necessary adjust for the reported movement in provisions. The AER also requires SP AusNet to verify the AER's assumed allocation of costs related to its movement in provisions for 2006–09.

Treatment of related party margins

The ESCV in deriving its benchmark allowances for the 2006–10 regulatory control period excluded related party margins (referred to as contractual arrangements).[125]

[124] ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 168.

Accordingly, in assessing the carryover amounts, the Victorian DNSPs actual expenditure should be exclusive of these margins. The AER notes that from 2007 the DNSPs were required to report actual expenditure exclusive of related party margins.[126] Accordingly, the AER has not adjusted actual expenditure for related party margins in 2007 and 2008. The AER notes that none of the Victorian DNSPs proposed removing the impact of the related party margins from actual expenditure in calculating the efficiency carryover amounts. Accordingly, to ensure that actual expenditure and the ESCV benchmark allowance is compared ‘like for like’, the AER has excluded the related party margins in 2006 in the carryover amounts for the Victorian DNSPs.[127] The AER's proposed adjustments for related party margins are detailed in table 13.5. The AER will apply CitiPower's, Powercor's, Jemena's and SP AusNet's reported expenditure exclusive of related party margins for 2009 to determine the carryover amounts for the final decision.

AER conclusion

In calculating the Victorian DNSPs' efficiency carryover amounts to ensure comparability between the ESCV benchmark allowance and actual expenditure the AER has excluded the amount of actual related party margins for 2007 and 2008. The AER will apply the DNSP 2009 reported expenditure exclusive of related party margins in its draft decision.

Other adjustments

The AER has also considered a number of adjustments proposed by the Victorian DNSPs as detailed as follows:

Licence fee

CitiPower and Powercor confirmed that licence fees were excluded from the actual operating and maintenance expenditure in the ECM calculation,[128] while the other Victorian DNSPs have included licence fees in the ECM calculation.[129] In its 2006 EDPR, the ESCV decided to allow for the recovery of the Victorian DNSPs licence fees directly in the price control. This allowed the Victorian DNSPs to pass through the actual cost of their licence fees as an adjustment to the price control rather than estimating future licence fees as part of the revenue requirements.[130] As licence fees were not included in the ESCV benchmark allowance, the AER has made some adjustments to the carryover amounts for Jemena and SP AusNet to exclude the costs of licence fees from actual expenditure where appropriate. The AER will review the actual licence fee for 2009 in its final decision and where necessary adjust the

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125 ibid., pp. 161–162.

126 ESCV, *Electricity Industry Guideline No. 3 Regulatory Information Requirements Issue No. 6,* December 2006, p. 20.

127 The AER notes that there is a discrepancy between the amount of reported related party margins in CitiPower and Powercor's reported expenditure and its regulatory proposals for 2007 and 2008. In calculating CitiPower and Powercor's carryover amounts the AER has excluded the amount for related party margins reported by CitiPower and Powercor.

128 CitiPower and Powercor, *Response to AER information request*, 25 February 2010.

129 SP AusNet, *Response to AER information request*, 23 February 2010; Jemena, *Response to AER information request*, 23 February 2010; United Energy, *Response to AER information request*, 23 February 2010.

130 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 470.

Victorian DNSPs' (with the exception of CitiPower and Powercor) carryover amounts to reflect the actual licence fee paid.

AMI reclassification—CitiPower and Powercor

In its AMI review, the AER identified discrepancies between the Victorian DNSPs' AMI charges relating to metering expenditure for 2006–08 and audited regulatory accounts for metering during 2006–08. The AER stated it would only accept the audited regulatory accounts when assessing AMI. CitiPower and Powercor subsequently undertook an independent re-audit of their regulatory accounts to confirm the AMI expenditure and revenues proposed to the AER for 2006–08. The AER used these re-audited regulatory accounts in its final determination when setting CitiPower and Powercor's AMI budgets and charges for 2009–11. CitiPower and Powercor have now proposed further adjustments to these re-audited regulatory accounts.[131]

The AER has not accepted these further amendments to its regulatory accounts for 2006–08 on the basis it will only accept the audited regulatory accounts (in this case the re-audited regulatory accounts). Accordingly, the AER has made some adjustments to CitiPower and Powercor's carryover amounts where the allocation of costs in its regulatory proposal to AMI is inconsistent with its re-audited regulatory accounts. These adjustments are detailed in table 13.5.

Non-network activities

The AER noted inconsistencies in actual operating and maintenance expenditure between Jemena's RIN and reported expenditure (i.e. regulatory accounts for 2006–08), as a result of the adjustment for non-network activities. Jemena stated that those adjustments were related to avoided distribution use of system costs paid to embedded generators.[132]

Given the ESCV benchmark allowance includes the costs paid to the embedded generators for avoided distribution costs, the AER has not excluded these costs from actual expenditure as proposed by Jemena. The AER notes that costs associated with non-network initiatives are to be excluded from the EBSS and this includes any avoided distribution payments provided by the Victorian DNSPs to embedded generators over the forthcoming regulatory control period (refer to chapter 17).

AER conclusion

The AER has made some adjustments to the carryover amounts for Jemena and SP AusNet to exclude the costs of licence fees from actual expenditure where appropriate. The AER will review the actual licence fee for 2009 in its final decision and where necessary adjust the Victorian DNSPs' (with the exception of CitiPower and Powercor) carryover amounts to reflect the actual licence fee paid.

Accordingly, the AER has made some adjustments to CitiPower and Powercor's carryover amounts where the allocation of costs in its regulatory proposal to AMI is inconsistent with its re-audited regulatory accounts.

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[131] CitiPower, *Regulatory proposal*, pp. 7–8; Powercor, *Regulatory proposal*, pp. 6–8.
[132] Jemena, *Response to AER information request*, 23 February 2010.

The AER has not excluded Jemena's costs associated with avoided distribution costs identified in its regulatory proposal from the calculation of its carryover amounts.

13.5.5 Treatment of uncontrollable and non-recurrent costs

The Victorian DNSPs have proposed adjusting the ESCV benchmark allowance and the actual expenditure over the current regulatory control period for uncontrollable and non-recurrent costs.

Victorian DNSP regulatory proposals

CitiPower and Powercor proposed adjustments to the *ESCV benchmark allowance* to account for unforeseen and uncontrollable changes in the scale and scope of their activities, which include:

- superannuation costs incurred between 2006 and 2009 which have varied significantly due to share market volatility
- payment of guaranteed service level (GSL) payments to customers due to climate related impacts on its network.[133]

CitiPower and Powercor argued that such an adjustment is necessary on the basis that:

- these costs are uncontrollable and were not foreseen when the 2006–10 forecasts were prepared
- those forecasts assumed that superannuation costs would be consistent in each year of the current regulatory control period
- a 'like for like' comparison between actual and forecast expenditure is not possible unless an adjustment is made to the benchmark
- in the NSW Final Determination, the AER accepted superannuation costs were an uncontrollable cost that should be excluded from the EBSS.[134]

In addition, CitiPower and Powercor proposed adjustments to the ESCV benchmark allowance to remove the ESCV forecast efficiency improvement, which excluded the impact of the partial productivity factor in the rate of change factor that was equivalent to –0.39 per cent per annum.[135] Powercor also proposed an adjustment ($5.5 million) to the 2006 ESCV benchmark allowance.[136] CitiPower and Powercor argued that these adjustment are necessary so that the efficiency carryover calculation for the 2006–10 regulatory control period is consistent with the principles set out in

[133] CitiPower, *Regulatory proposal*, pp. 250–254; Powercor, *Regulatory proposal*, pp. 254–259.
[134] CitiPower, *Regulatory proposal*, pp. 253; Powercor, *Regulatory proposal*, pp. 258.
[135] CitiPower, *Regulatory proposal*, pp. 254–255; Powercor, *Regulatory proposal*, pp. 259–260;
[136] Powercor, *Regulatory proposal*, p. 260.

the AER’s EBSS and with the requirements of clause 6.5.8(c) of the NER and section 7A(3) of the NEL. [137]

Powercor has also proposed the following adjustments to *actual expenditure*, which include:

- non-recurrent costs – Australian Tax Office audit

- costs not included in ESCV benchmark allowance (i.e. incremental vegetation clearance).[138]

CitiPower and Powercor argued that these adjustments are consistent with:

- the approach taken by the ESCV in the 2006–10 EDPR

- the decision of the Appeal Panel in 2000 in Powercor Australia's successful appeal of the 2001–05 EDPR in relation to the ORG's refusal to make certain adjustments sought by Powercor

- the AER's Guideline, which provides for adjustments to exclude pass through events and other nominated uncontrollable costs from the application of the EBSS.[139]

SP AusNet proposed adjustments to *actual expenditure* which it deemed as non-recurrent, including:

- $13.67 million ($2009) for the incremental costs associated with the February 2009 bushfires

- $2.99 million ($2009) for the costs that SP AusNet has paid to SPIMS for the actuarial adjustment pertaining to its defined benefits superannuation contribution.[140]

SP AusNet submitted that excluding these costs from the efficiency carryover calculation is consistent with the ESCV benchmark allowance opex amounts, as the ESCV did not make any allowance for opex that may be incurred by SP AusNet from time-to-time in relation to bushfire events and superannuation adjustment.[141] In addition, SP AusNet stated that such adjustments are also consistent with the ESCV’s requirement that any efficiency carryover mechanism only focuses on changes in ‘recurrent’ operating expenditure—which these events are not.[142]

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137 CitiPower, *Regulatory proposal*, pp. 254–255; Powercor, *Regulatory proposal*, pp. 259–260; NERA, *Treatment of Accrued Carryovers in the 2011–15 Regulatory Period*, December 2009, p. 21.
138 Powercor, *Regulatory proposal*, pp. 259–260.
139 CitiPower, *Regulatory proposal*, p. 250; Powercor, *Regulatory proposal*, p. 254.
140 SP AusNet, *Response to AER information request*, 24 March 2010.
141 SP AusNet, *Regulatory proposal*, p. 261.
142 SP AusNet, *Response to AER information request*, 24 March 2010.

Submissions on DNSP regulatory proposals

No submissions were received on this issue.

AER considerations

In considering Powercor's arguments that the AER should exclude the impact of uncontrollable costs from the calculation of the efficiency carryover amounts the AER has reviewed the ESCV's past practice.

ESCV treatment of uncontrollable costs

As discussed in section 13.5.2, in establishing the ECM the ESCV did not design the ECM such that uncontrollable costs should be identified and excluded from the carryover amounts. The AER notes that the ESCV has previously recognised that the efficiency carryover amounts may include both management induced efficiency and windfall gains and losses.

However, given the difficulties of separately identifying management (in) efficiencies from windfall gains and losses no attempt was made to distinguish the two. Most importantly, the Victorian DNSPs' carryover calculation may have included some 'efficiency gains' that may not have been the result of management effort. The AER notes that neither the ESCV in its 2006 EDPR nor stakeholders including the Victorian DNSPs identified uncontrollable as a relevant consideration for determining the carryover amounts for 2011–15.

In addition, as discussed in section 13.5.2, Powercor did not favour distinguishing between uncontrollable (windfall gains) and controllable (management induced efficiencies) costs on the grounds that such an approach would involve significant regulatory risks, administrative and compliance costs and lessen and distort incentives for efficient behaviour.[143]

In response to Powercor's view that an adjustment to the ECM is consistent with the Appeal Panel Decision for the 2001–05 EDPR, the AER notes that the Appeal Panel rejected the ORG's decision not to make adjustments to Powercor's actual 1995–99 costs associated with network growth. The ESCV in its 2006 EDPR included a growth adjustment formula to account for changes in operating and maintenance expenditure related to network growth. The AER has made adjustments for network growth in the calculation of ECM for the Victorian DNSPs consistent with the formula specified by the ESCV in its 2006 EDPR (refer to section 13.5.3). Given the Appeal Panel decision was limited to growth adjustments in the calculation of the carryover amounts, the AER does not consider that this decision provides any expectation that uncontrollable costs would be excluded from the carryover amounts for 2011–15.

In contrast, the AER states in its EBSS Final Decision[144] that the AER will permit a DNSP to propose a range of additional cost categories (includes uncontrollable costs) for exclusion from the operation of the EBSS which are specific to a DNSP, and do not involve an ongoing business activity. However, a DNSP must propose cost

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143 Powercor, *Efficiency Measurement and Benefit Sharing – Submission to the Office of the Regulator–General's 2001 Electricity Distribution Price Review*, February 1999, pp. 9–11.

144 AER, *Final Decision Electricity DNSPs EBSS*, June 2008, appendix E p. 6.

categories for exclusion from the EBSS in their regulatory proposal prior to the commencement of the regulatory control period during which the EBSS will be applied. That is, the AER will not accept ex post adjustments to either the benchmark allowance or actual expenditure to account for cost categories that have not been identified ex ante in the EBSS.[145] This is necessary to preserve the ex ante incentives established by the EBSS. Conversely, as noted above the ESCV's ECM as specified in its 2006 EDPR did not specify any adjustments ex ante to the ESCV benchmark allowance for uncontrollable costs. The AER also notes that the 2006 EDPR[146] stated that efficiency gains and losses would be treated symmetrically in calculating efficiency carryover amounts from the 2001–05 regulatory control period. This means that the DNSPs may also receive some windfall gains (that is, uncontrollable cost reductions) over the regulatory control period. However, given the information asymmetry between the Victorian DNSPs and the AER, it would be difficult to identify any windfall gains received by the Victorian DNSPs.

ESCV treatment of non-recurrent costs

In its 2006 EDPR the ESCV provided guidance as to how the ECM would be applied in the 2010 review. In particular, the ESCV stated that the efficiency carryover amounts for operating and maintenance expenditure (opex) to be included in the 2011 revenue requirements will be calculated as follows:

- an efficiency gain (or loss) in opex in any year during the 2006–10 regulatory control period is to be calculated as the reduction (or increase) in the level of recurrent opex compared to the forecast for that year

- recurrent in this sense is taken as the underspend (overspend) between forecast and actual in year one and the incremental underspend (overspend) in subsequent years.[147]

The ESCV stated further that the incremental calculation method of operating and maintenance expenditure in its ECM ensures that the rewards to the Victorian DNSPs through the efficiency carryover mechanism are only retained where they are sustainable.[148] In addition, the ESCV also noted that a substantial one off expenditure increase in any year would be offset by the positive carryover associated with the relative efficiency improvement when expenditure returns to normal levels in the following year.[149] The AER also notes that the ESCV in establishing the base year level of expenditure did not explicitly exclude non-recurrent costs.

AER approach to non-recurrent costs for the Victorian DNSPs

The AER recognises that where a non-recurrent cost is incurred in the base year and these costs are excluded in establishing the base year level of expenditure to forecast opex, the DNSP will:

- register an efficiency loss to be carried forward for five years; and

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145 The AER has previously stated that it does not accept ex post adjustments to the EBSS on the basis that this will introduce unnecessary regulatory uncertainty.
146 ESCV, *EDPR 2006–10*, Volume 1, October 2006, p. 424.
147 ibid., p. 431.
148 ibid., p. 416.
149 ibid., p. 435.

- receive a lower opex forecast over the forthcoming regulatory control period by the same amount.

In considering this issue the AER notes that the ESCV stated in its 2006 EDPR that:

> In so far as the carryover amounts for operating and maintenance expenditure arising from the 2006–10 regulatory period and to be applied in the 2011 regulatory period are concerned, the presumption will be that, where a negative carryover amount arises, it will be applied in calculating the building blocks revenue requirement for the 2011 period. However, taking into account the prevailing regulatory arrangements at that time, future regulators should exercise discretion in determining whether this presumption should be applied to negative efficiency carryover amounts based on the circumstances that have given rise to the negative efficiency carryover amounts. [150]

This suggests that the AER should adopt the presumption that where a negative carryover arises, it will be applied in determining the Victorian DNSPs' building block revenue for 2011–15. That said, the AER has some discretion as to whether this presumption will be applied taking into account the circumstances that have given rise to the negative efficiency carryover amounts—in this case whether to apply the negative carryover arising from the occurrence of non-recurrent costs in the base year.

The AER has excluded non recurrent costs from the determination of forecast opex as set out in chapter 7. The AER in this draft decision has excluded these costs from the base year for the purpose of ensuring that DNSPs have an incentive to reveal efficient costs over the forthcoming regulatory period. Therefore based on these circumstances, the AER has decided to override the presumption and not apply the negative carryover amounts associated with non recurrent costs that are incurred in the base year. The AER has done this because this will remove the efficiency loss to be carried forward for five years thereby resulting in the abatement of incentives for DNSPs to reveal their efficient level of costs over the forthcoming regulatory control period contrary to clause 6.5.8(c) of the NER. These adjustments are reflected in table 13.5.

AER conclusion

The AER, in calculating the efficiency carryover amounts from the ESCV's ECM, has not adjusted the benchmark allowance for uncontrollable costs on the basis that:

- the ESCV did not explicitly allow for these adjustments in its ECM to apply to the Victorian DNSPs for the 2011–15 regulatory control period
- the Victorian DNSPs did not raise the issue of uncontrollable costs in the ECM in the 2006 EDPR and have previously criticised any attempts to distinguish between management induced efficiencies and windfall gains
- any adjustment for windfall losses would require a consideration of windfall gains (however, given the information asymmetry, the DNSPs may not identify windfall gains)

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150 ibid., p. 435.

- the AER has decided to override the presumption in the ECM to apply negative a carryover amounts [151] where this negative carryover amount arises due to the occurrence of a non-recurrent cost in the base year on the basis that the inclusion of non-recurrent costs in determining the carryover amounts may reduce the Victorian DNSPs' incentives to reveal their efficient costs over the forthcoming regulatory control period, contrary to clause 6.5.8(c) of the NER.

The AER's adjustments to the Victorian DNSPs' 2006–10 benchmark allowances and their reported expenditure for the purposes of calculating the carryover amounts for the forthcoming regulatory control period are outlined in table 13.4and table 13.5 respectively.

[151] ibid., p. 435.

Table 13.4 AER conclusion on adjustments to 2006–10 opex benchmark ($'m, 2010)

	2006	2007	2008	2009	2010
CitiPower					
Original benchmark opex	40.4	41.7	41.8	42.7	43.5
Capitalisation policy	0.0	0.0	0.0	0.0	0.0
Growth adjustment	–0.3	–0.6	–0.8	–1.1	–1.4
Revised benchmark opex	40.1	41.1	41.0	41.6	42.1
Powercor					
Original benchmark opex	135.3	138.4	141.0	144.1	147.8
Capitalisation policy	0.0	0.0	0.0	0.0	0.0
Growth adjustment	0.3	0.7	1.0	1.3	1.7
Revised benchmark opex	135.6	139.1	142.1	145.5	149.5
Jemena					
Original benchmark opex	59.4	60.4	61.6	62.9	64.4
Capitalisation policy	0.0	0.0	4.6	4.6	4.6
Growth adjustment	0.0	0.0	0.1	0.1	0.1
Revised benchmark opex	59.4	60.4	66.2	67.6	69.1
SP AusNet					
Original benchmark opex	126.6	129.8	133.2	136.6	140.3
Capitalisation policy	–15.7	–12.0	–15.9	–15.9	–15.9
Growth adjustment	–0.1	–0.2	–0.4	–0.5	–0.6
Revised benchmark opex	110.8	117.5	117.0	120.2	123.9

Source: AER analysis.

Table 13.5 AER conclusion on adjustments to 2006–10 reported opex ($'m, 2010)

	2006	2007	2008	2009 (estimate)
CitiPower				
Reported/estimated opex	[c-i-c]	34.9	33.7	36.8
Provisions	0.1	–2.1	–2.5	0.6
AMI adjustment	0.7	–1.1	0.0	0.0
Licence fees	–0.8	–0.6	–0.5	–0.6
Related party margins	[c-i-c]	–	–	–
Non-recurrent expenditure	–	–	–	–0.6
Revised opex	27.8	31.1	30.8	36.1
Powercor				
Reported/estimated opex	[c-i-c]	113.7	119.3	124.9
Provisions	–0.3	1.9	–8.3	3.0
AMI adjustment	0.7	–1.1	–	–
Licence fees	–1.7	–0.8	–0.8	–0.8
Related party margins	[c-i-c]	–	–	–
Non-recurrent expenditure	–	–	–	–7.3
Revised opex	127.1	113.7	110.3	119.8
Jemena				
Reported/estimated opex	54.4	57.4	48.3	47.2
Provisions	–0.2	–0.1	0.4	–
Licence fees	–0.8	–	–0.4	–
Related party margins	–	–	–	–
Revised opex	53.5	57.3	48.3	47.2
SP AusNet				
Reported/estimated opex	92.9	113.2	124.8	141.0
Provisions	–1.3	–0.3	–0.3	–
Licence fees	–0.6	–1.0	–0.6	–0.3
Related party margins	–	–	–	–
Non-recurrent expenditure	–	–	–	–16.9
Revised opex	91.0	111.9	123.9	123.8

Source: AER analysis.

13.6 AER conclusion

The Victorian DNSPs' proposed carryover amounts are detailed in table 13.1. The AER notes that this is a decision in relation to other inputs, values and amounts in the building block model, in accordance with clause 6.12.1(10) of the NER. The AER has reviewed the Victorian DNSPs' proposed ECM and has not applied the ECM to United Energy (as noted in section 13.5.1). The AER has also made adjustments to the Victorian DNSPs' proposed carryover amounts in relation to:

- inclusion of the accrued negative carryover amounts arising from the 2001–05 regulatory control period (Powercor only as noted in section 13.5.2)
- ex post adjustments to the benchmark allowance associated with network growth (as noted in section 13.5.3)
- adjustments to the benchmark allowance and actual expenditure to ensure comparability between the benchmark allowance and actual expenditure (as noted in section 13.5.4)
- other adjustments (as noted in section 13.5.4)
- non-recurrent costs that occur in the base year (as noted in section 13.5.5).

In accordance with clauses 6.4.3(a)(6) and 6.12.1(9) of the NER, and the AER's EBSS for this draft decision, the AER has applied the ECM for Victorian DNSPs as set out in table 13.6. This value is used as an input to the Post Tax Revenue Model (PTRM) for the purposes of determining the Victorian DNSPs' annual building block revenue requirement during the forthcoming regulatory control period.

Table 13.6 AER conclusion on the Victorian DNSPs' carryover amounts 2011–15 ($'m, 2010)

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

Source: AER analysis.

14 Efficiency benefit sharing scheme

14.1 Introduction

This chapter sets out how the AER will apply its efficiency benefit sharing scheme (EBSS) to the Victorian DNSPs in the forthcoming regulatory control period. The EBSS shares between DNSPs and distribution network users the efficiency gains or losses derived from the difference between a DNSP's actual opex and the forecast opex allowance for a regulatory control period.

In accordance with clause 6.5.8(a) of the National Electricity Rules (NER), the AER has published an EBSS which establishes a scheme that will apply to the Victorian DNSPs from 1 January 2011.[1]

In its Framework and approach paper, the AER stated that its likely approach for the Victorian DNSPs' distribution determinations would be to apply the national EBSS during the forthcoming regulatory control period.[2] However, the scheme will not have a direct financial impact until the 2016–20 regulatory control period, when the Victorian DNSPs will receive carryover benefits or penalties for efficiency gains or losses realised during the 2011–15 regulatory control period.

The AER notes that no submissions were received on the EBSS.

14.2 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.

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1 AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008.

2 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, regulatory control period commencing 1 January 2011*, May 2009, pp. 112–113.

First year formula

The EBSS states that the AER will calculate an efficiency gain or loss in the first year of the regulatory control period using the following formula:

$$E_1 = F_1 - A_1$$

where:

E_1 = the efficiency gain/loss in year 1

A_1 = actual opex incurred by the DNSP for year 1 of the regulatory control period

F_1 = forecast opex accepted or substituted by the AER in the distribution determination for year 1 of the regulatory control period.

Subsequent years' formula

Gains or losses that arise in the second and subsequent years of the regulatory control period will be calculated as:

$$E_t = (F_t - A_t) - (F_{t-1} - A_{t-1})$$

where:

E_t = the efficiency gain/loss in year t

A_t, A_{t-1} = the actual, or adjusted actual, opex incurred in years t and t–1 respectively

F_t, F_{t-1} = the forecast, or adjusted forecast, opex accepted or substituted by the AER for years t and t–1 respectively.

The AER will use this formula to calculate efficiency gains for the years 2012 to 2015.

Final year formula

As the distribution determination for the 2016–20 regulatory control period will be made prior to the completion of the forthcoming regulatory control period, the AER will estimate the actual opex required to calculate gains or losses for the final year of the forthcoming regulatory control period, that is 2015, as follows:

$$A_5 = F_5 - (F_4 - A_4)$$

Where differences arise between this estimate and the actual expenditure in the final year, the efficiency gain or loss in the first year of the 2016–20 regulatory control period (E_6) will be adjusted as follows:

$$E_6 = (F_6 - A_6) - (F_5 - A_5) + (F_4 - A_4)$$

Given that the Victorian DNSPs have been operating under an efficiency carryover mechanism that is substantially similar to the AER's efficiency benefit sharing scheme the AER will use this formula to calculate efficiency gains or losses under the EBSS for 2011, rather than the first year formula above.

Other provisions

The EBSS also provides for:

- adjustments to forecast opex allowances for the purpose of calculating carryover amounts to account for changes to a DNSP's capitalisation policies
- adjustments to forecast opex allowances for the purpose of calculating carryover amounts to account for variations between forecast and outturn growth
- DNSPs to propose cost categories to be excluded from the operation of the EBSS.

14.3 Summary of Victorian DNSP regulatory proposals

For the purpose of calculating EBSS carryover amounts, the AER allows for adjustments to forecast opex for the cost consequences of changes to a DNSP's capitalisation policy. The Victorian DNSPs did not propose any changes to their current capitalisation policies for the forthcoming regulatory control period.

The AER also allows for adjustments to account for outturn growth in a DNSP's network. CitiPower and Powercor did not propose a method for such adjustments. Jemena and United Energy proposed that the growth adjustment formula developed by the Essential Services Commission of Victoria (ESCV) for the current regulatory control period should be used.[3] SP AusNet proposed an alternative growth adjustment method.[4]

The EBSS also allows DNSPs to propose additional cost categories to be excluded from the operation of the EBSS. The Victorian DNSPs, except Jemena, proposed a range of costs to be excluded from the EBSS, including:

- guaranteed service level (GSL) payments
- superannuation contributions
- debt and equity raising costs
- self insurance and insurance costs
- the demand management innovation allowance (DMIA)
- changes in classification of a service
- adjustments for changes in regulatory responsibilities

3 Jemena, *Regulatory proposal 2011-2015, 30 November 2009*, p. 208; and United Energy, *Regulatory proposal for Distribution Prices and Services, January 2011–December 2015*, November 2009, p. 220.

4 SP AusNet, *Electricity Distribution Price Review, Regulatory proposal*, November 2009 p. 267.

- proposed nominated pass through events not determined by the AER to be pass through events
- expenditure that meets all of the necessary requirements for an approved pass through event other than satisfying the materiality threshold.[5]

The AER notes that Jemena did not propose any excluded cost categories to apply to the EBSS for the forthcoming regulatory control period.

14.4 Issues and AER considerations

14.4.1 Changes to capitalisation policies

In developing the EBSS, the AER recognised that a DNSP's actual opex may be affected by any changes made to a DNSP's capitalisation policy.[6] The EBSS requires that, for the purpose of calculating efficiency carryover amounts, forecast opex should be adjusted for any changes made to a DNSP's capitalisation policy. This ensures that the AER is able to compare actual and benchmark opex on a like for like basis, and provides a more accurate measure of efficiencies achieved by a DNSP in the forthcoming regulatory control period.

Victorian DNSP proposals

The Victorian DNSPs did not propose any specific changes to their capitalisation policies for the forthcoming regulatory control period. CitiPower and Powercor stated that a portion of their corporate costs are capitalised, and that the amount capitalised is based on a percentage of direct costs. CitiPower and Powercor also advised that consideration was currently being given to alignment of their respective capitalisation policies from 2011.[7]

United Energy submitted that its capitalisation policies were not expected to change for the forthcoming regulatory control period. United Energy also stated that if its policies do change in future, appropriate adjustments to EBSS calculations will be made in accordance with the scheme.[8] Similarly, SP AusNet did not propose any changes to its capitalisation policy for the forthcoming regulatory control period.[9]

Jemena proposed to use the same capitalisation policy for the forthcoming regulatory control period as used in the final years of the current regulatory control period, and to use this capitalisation policy to determine its opex forecast for the forthcoming regulatory control period.[10]

AER considerations

In their regulatory proposals, the Victorian DNSPs did not identify any specific changes to their capitalisation policies for the forthcoming regulatory control period.

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5 CitiPower, *Regulatory proposal*, pp. 247–248; Powercor, *Regulatory proposal*, pp. 251–252; United Energy, *Regulatory Proposal*, p. 218; and, SP AusNet, *Regulatory Proposal*, p. 257.
6 AER, *Final decision, Electricity DNSPs EBSS*, June 2008, p. 6.
7 CitiPower, *Regulatory proposal*, p. 247; Powercor, *Regulatory proposal*, p. 251.
8 United Energy, *Regulatory proposal*, pp. 220–221.
9 SP Ausnet, *Regulatory proposal*, p. 263.
10 Jemena, *Regulatory proposal*, p. 208.

Where a DNSP alters its capitalisation policy during the forthcoming regulatory control period, the AER will adjust forecast and actual opex amounts in accordance with the EBSS when calculating carryover amounts.

14.4.2 Growth adjustments

In developing the EBSS, the AER recognised that a DNSP's opex may be affected by the actual level of growth experienced in a network.[11] The EBSS allows for forecast opex to be adjusted for variances between forecast and outturn growth over the regulatory control period for the purposes of calculating carryover amounts. This is intended to prevent a DNSP from being penalised or rewarded for changes in opex that are directly attributable to growth beyond its control.

This approach ensures that the AER is able to compare actual and benchmark opex on a like for like basis, and provides a more accurate measure of efficiencies achieved by a DNSP in the forthcoming regulatory control period.

Victorian DNSP proposals

Neither CitiPower nor Powercor proposed a specific growth adjustment method for the purpose of calculating EBSS carryover amounts for the forthcoming regulatory control period. The AER notes that for the purpose of calculating forecast opex for the forthcoming regulatory control period both CitiPower and Powercor proposed that opex be adjusted to account for network growth, growth in work volume, and growth in customer numbers, as discussed in appendix J.[12]

United Energy proposed that for the purpose of calculating carryover amounts accrued over the 2011–15 regulatory control period, the growth adjustment formula developed by the ESCV for the current regulatory control period should be used.[13] United Energy noted that changes in customer numbers, energy consumption and peak load all have a bearing on actual opex, and where the outturn values of these variables differ from the amounts forecast, then it is appropriate to make revisions to opex projections for the purpose of applying the EBSS.[14]

United Energy noted that its opex forecasting methodology did not explicitly apply growth factors to produce the forecast expenditure. Instead, United Energy's forecasting methodology adopted an asset management plan to set volumes, and used contractors to manage price risks, as discussed in appendix J.[15] Given this, United Energy considered it necessary to propose an alternative growth adjustment for the purposes of the EBSS.[16]

Jemena also proposed that, for the purpose of calculating carryover amounts, the growth adjustment formula developed by the ESCV for the current regulatory control

[11] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, p. 6.
[12] CitiPower, *Regulatory proposal*, pp. 164–166; Powercor, *Regulatory proposal*, pp. 160–162.
[13] ESCV, *Electricity Distribution Price Review 2006–10, Final decision*, Volume. 1, October 2006, pp. 415–436; United Energy, *Regulatory proposal*, p. 220.
[14] United Energy, *Regulatory proposal*, p. 220.
[15] ibid., pp. 46–52.
[16] ibid., p. 220.

period should be used.[17] The AER notes that this approach is broadly consistent with the approach that Jemena proposed to account for growth in its opex forecasts, which is discussed in appendix J. The approach applies a weighted opex growth rate for energy consumption, customer numbers and peak demand to account for growth in the forthcoming regulatory control period.[18]

SP AusNet proposed that no adjustment be made to the EBSS calculation to account for differences between forecast and actual energy consumption and maximum demand, as it did not consider these to be material drivers of SP AusNet's opex. However, SP AusNet stated that there is a small relationship between customer number forecasts and opex. SP AusNet proposed that the following growth adjustment be used to account for this relationship between opex and customer numbers:[19]

((Actual Customer numbers)/(Forecast customer numbers)) –
1*0.41%*36.16%

The AER notes that this approach is not consistent with the approach SP AusNet has proposed to account for growth in its opex forecasts, which is discussed in appendix J. To account for growth in its opex forecasts SP AusNet identified the cost drivers for each opex category, estimated the fixed and variable costs for each category, and then applied the cost drivers to the estimated variable portion of its efficient base year operating costs.[20]

AER considerations

The growth adjustment was incorporated into the EBSS to prevent DNSPs from being penalised or rewarded for changes in growth beyond the control of the DNSP.[21] The AER considers that opex projections should be adjusted for the cost consequences of any differences between forecast and actual growth over the forthcoming regulatory control period. However, the AER also notes that adjustments should only be applied to those components of opex which can be shown to be directly affected by growth.

The AER considers that any ex-post adjustment to forecast opex for the purposes of calculating efficiency carryover amounts should use the same method as used to account for growth in the original opex forecasts where practical. This ensures that the forecast opex amounts used to calculate carryover amounts are the same as those that would have been provided to the DNSPs in their regulatory allowance had the level of network growth that would occur been known with certainty.

The AER notes that only Jemena proposed a growth adjustment method for the EBSS that was consistent with the approach proposed to account for growth in its opex forecast.

The AER has considered the methods used by the DNSPs to escalate their opex forecasts to account for growth in appendix J. The AER concluded that growth factors

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17 ESCV, *EDPR 2006–10*, vol. 1, October 2006, pp. 415–436; Jemena, *Regulatory proposal*, p. 208.
18 Jemena, *Regulatory proposal*, pp. 135–136.
19 SP AusNet, *Regulatory proposal*, p. 267.
20 ibid., pp. 173, 213.
21 AER, *Electricity DNSPs EBSS*, Final decision, June 2008, p. 5.

based on physical metrics such as line length and the number of distribution transformers and zone substations result in forecasts of opex that most closely reflect the actual growth in operating and maintenance activity levels.

Accordingly, the AER has adopted two growth drivers for each DNSP for the draft decision:

1. a composite network growth factor calculated as a simple average of the annual growth in line length and the number of distribution transformers and zone substations over the forthcoming regulatory control period
2. the annual growth in customer numbers over the forthcoming regulatory control period.

When the AER calculates the efficiency carryover amounts for efficiency gains or losses made in the forthcoming regulatory control period it will adjust the opex forecasts using this same method. That is, it will remove the growth escalation applied in determining the DNSPs' opex allowances and will reapply the same method using the actual growth in line length, the number of distribution transformers and zone substations, and customer numbers experienced over the forthcoming regulatory control period.

14.4.3 Excluded cost categories

The EBSS provides for a range of adjustments and cost exclusions in the calculation of efficiency carryover amounts.[22] In addition, the EBSS allows DNSPs to propose additional cost categories to be excluded from the EBSS.[23] The scheme requires these cost categories to be proposed by a DNSP in its regulatory proposal for the forthcoming regulatory control period.

Victorian DNSP proposals

The Victorian DNSPs proposed that recognised pass through events and opex for non-network alternatives should be excluded for the purpose of calculating efficiency gains and losses under the EBSS. In addition to this, CitiPower and Powercor proposed that the following costs also be excluded from the EBSS for the forthcoming regulatory control period:[24]

- GSL payments
- superannuation contributions
- debt raising costs.

CitiPower and Powercor noted that these exclusions are proposed on the basis that these costs are outside the control of the businesses, have proven to be relatively

22 AER, *Electricity DNSPs EBSS*, Final decision, June 2008, pp. 6–7.
23 ibid., p. 5.
24 CitiPower, *Regulatory proposal*, p. 247; Powercor, *Regulatory proposal*, p. 251.

volatile, and that their exclusion would not adversely impact on the operation of the EBSS.[25]

CitiPower and Powercor also proposed that if the AER does not agree to treat any of their proposed nominated pass through events as pass through events then the costs related to any of those events should be treated as uncontrollable costs for the purposes of the EBSS.[26]

United Energy proposed that the following cost categories also be excluded from the EBSS for the forthcoming regulatory control period:

- debt and equity raising costs
- self insurance costs
- insurance costs
- expenditure that meets all of the necessary requirements for an approved pass through event other than satisfying the materiality threshold.[27]

United Energy noted that the first three of these cost categories were drawn from the New South Wales final distribution determination,[28] and that the management of these particular costs is beyond a DNSP's normal business activities. In relation to pass through costs, United Energy considered that while it was reasonable to apply a materiality test to the pass through of costs to customers, it was not appropriate to apply the same threshold for the purpose of calculating EBSS payments.[29]

In addition to the cost categories in relation to the EBSS listed in the AER's New South Wales final distribution determination, SP AusNet proposed that the following costs be excluded from the EBSS for the forthcoming regulatory control period:

- insurance premiums
- self insurance costs
- debt raising costs.[30]

SP AusNet noted that these costs are subject to market volatility that is driven by factors beyond the control of SP AusNet.[31]

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25 ibid.
26 CitiPower, *Regulatory proposal*, pp. 247–248; Powercor, *Regulatory proposal*, pp. 251–252.
27 United Energy, *Regulatory proposal*, p. 218.
28 AER, *New South Wales distribution determination 2009–10 to 2013–14*, *Final decision,* April 2009, pp. 245–250
29 United Energy, *Regulatory proposal*, p. 218.
30 SP AusNet, *Regulatory proposal*, pp. 266–267.
31 ibid.

Jemena did not propose any costs to be excluded from the EBSS for the forthcoming regulatory control period.

AER considerations

The AER considers two key factors when assessing whether an opex category should be excluded from the EBSS. The first factor is the degree of control that the DNSPs have over the expenditure. 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.[32]

The second factor is how actual expenditure for that cost category is used in setting opex forecasts for the regulatory control period following the period during which the EBSS applied. 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 calculated instead from an external benchmark, the EBSS would not provide a continuous incentive to reduce opex. Consequently, in implementing the EBSS, these costs should be excluded to provide the DNSPs a continuous incentive to reduce opex, which the AER must have regard to under clause 6.5.8(c)(2) of the NER.

Having considered these factors, the AER considers it appropriate to exclude the following additional forecast opex costs, to the extent approved by the AER in its distribution determination, from the operation of the EBSS for the Victorian DNSPs for the forthcoming regulatory control period:

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

These excluded costs will be recognised in addition to the adjustments set out in section 2.3.2 of the EBSS, which include the costs of non-network alternatives and recognised pass through events.

The AER considers it appropriate that approved forecast debt and equity raising costs be excluded from the operation of the EBSS, on the basis that forecasts of these costs are based on a benchmark efficient firm rather than the historical costs of the DNSP. Consequently they should be excluded to provide DNSPs with a continuous incentive to reduce opex, which the AER must have regard to under clause 6.5.8(c)(2) of the NER. To the extent that benchmark cash flow analysis, based on the capex allowance, demonstrates that a DNSP should be provided with an allowance for equity raising costs, the AER considers that the allowance should be amortised. In this draft decision the AER maintains that any equity raising allowance determined for the Victorian DNSPs will be added to the DNSPs' RABs and depreciated over the weighted average

[32] AER, *Electricity DNSPs EBSS*, June 2008, pp. 6–7.

standard life of its assets. Consequently, equity raising costs are already excluded from the operation of the EBSS as they are not a component of the Victorian DNSPs' forecast opex allowances.

Similarly, self insurance costs are based on independent expert analysis, not historical costs in the base year. Consequently, since actual self insurance costs do not directly influence the future opex forecast they should be excluded to provide DNSPs a continuous incentive to reduce opex, which the AER must have regard to under clause 6.5.8(c)(2) of the NER.

The AER notes that in previous distribution determinations insurance costs have been excluded from the EBSS because they have been forecast based on independent expert analysis, and not directly linked to historical costs.[33] However, in this draft decision the AER has determined an opex allowance for insurance for the forthcoming regulatory control period based on actual expenditure in 2009, as discussed in appendix L. Consequently, because actual insurance costs have been used to set costs going forward the AER considers that insurance costs should be included in the EBSS.

The DMIA developed by the AER, in accordance with clause 6.6.3 of the NER, provides DNSPs with an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each year of the forthcoming regulatory control period. The DMIA is designed to encourage DNSPs to pursue and implement efficient and innovative non-network solutions to growing demand and constraints on distribution networks. Under the EBSS, opex spent on non-network alternatives will be excluded from the actual and forecast opex amounts used to calculate carryover gains or losses.[34] Consequently the AER considers it reasonable that the DMIA be excluded from the operation of the EBSS. As discussed in chapter 7, the AER will require the Victorian DNSPs to provide forecast expenditure associated with any avoided distribution cost payments to embedded generators in order to exclude these non-network alternative costs from the EBSS.

The AER notes that many DNSP employees are members of a defined benefit superannuation scheme. 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 DNSPs have limited control over both of these factors, the AER considers it reasonable that the approved amount of superannuation costs for defined benefits and retirement schemes be excluded from the EBSS.

The AER's consideration of the GSL scheme to apply to the Victorian DNSPs for the forthcoming regulatory control period is discussed in chapter 15. The AER considers that DNSPs have a significant degree of control over the GSL payments they pay to network customers. GSL payments are made to customers when a DNSP fails to provide the standard of service prescribed under the GSL scheme. Where a DNSP

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33 AER, *New South Wales distribution determination 2009–10 to 2013–14, Final decision*, April 2009, p. 249; AER, *Queensland distribution determination 2010–11 to 2014–15, Final decision*, May 2010, p. 286; AER, *South Australia distribution determination 2010–11 to 2014–15, Final decision*, May 2010, p. 207.

34 AER, *Electricity DNSPs EBSS*, June 2008, p. 7.

meets all GSL requirements to customers, it is not obliged to provide any GSL payments and retains the opex allowance for these unrealised payments. Furthermore, events considered to be beyond the control of the DNSPs are excluded from the GSL scheme and do not give rise to GSL payments.

However, the AER also notes that the DNSPs' allowances for GSL payments are forecast based on an average of historic payments. Consequently the DNSPs already have a constant incentive to reduce their GSL payments. The AER considers that if the EBSS were applied to GSL payments then this would distort this continuous incentive to reduce GSL payments, which would be inconsistent with the requirements of clause 6.5.8(c)(2) of the NER. Thus, while the AER considers that GSL payments are controllable costs, GSL payments should be excluded from the EBSS in order to provide the DNSPs with a continuous incentive to reduce their GSL payments by improving service performance.

The nominated pass through events proposed by the Victorian DNSPs are considered in chapter 16. The AER notes that a number of the nominated pass through events proposed by the DNSPs were not accepted on the basis that they are events that are already within the scope of either the 'regulatory change event' or 'service standard event'. In accordance with section 2.3.2 of the EBSS approved increases or decreases in actual opex associated with recognised pass through events will be excluded from the actual expenditure amounts used to calculate carryover gains or losses under the EBSS.[35] The AER also notes that, some of the nominated pass through events proposed, such as a forced load shedding event, will impact revenues rather than costs. As such these events will not impact carryover amounts under the EBSS.

Having considered the nominated pass through events proposed by CitiPower and Powercor, the AER does not consider that any of these events should be excluded cost categories for the purposes of the EBSS because, for the reasons discussed above, they will not impact the outcomes of the EBSS.

The AER notes that United Energy also proposed that if an event occurs that does not meet the materiality threshold, but would otherwise be determined to be a pass through event, then the costs associated with the event should be excluded from the EBSS. However, under the EBSS, only the costs of recognised pass through events are excluded from the EBSS. The AER notes that by excluding such amounts from the EBSS, DNSPs would have an incentive to only inform the AER of events that result in higher EBSS carryover amounts. However, clause 6.5.8(c)(3) of the NER requires that in implementing the EBSS the AER must have regard to the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses. Consequently the AER considers that the cost associated with events that occur that do not meet the materiality threshold, but otherwise would have been determined to be pass through events, should be included in the EBSS.

It is important for the operation of the EBSS that the forecast and actual opex amounts used to calculate carryover amounts are on a like for like basis. The AER has not provided an opex allowance for related party margins. Consequently, when the AER calculates the EBSS carryover amounts at the end of the forthcoming regulatory

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35 AER, *Electricity DNSPs EBSS*, June 2008, p. 7.

control period it will use actual opex amounts exclusive of related party margins to ensure actual and forecast opex amounts are on a like for like basis.

The AER also notes that the EBSS states that where a standard control service does not remain a standard control service in the following regulatory control period (that is, 2016–20), the AER may remove the opex relating to that service from the actual and forecast opex figures used to calculate carryover amounts. Where this is the case, the AER may remove the opex relating to the service from the actual and forecast figures used to calculate carryover amounts, if it considers it appropriate to do so. The AER will consider factors, such as the materiality of the impact on carryover amounts and the associated potential for, and magnitude of, cross-subsidies, and whether there is any evidence of the DNSP inappropriately shifting costs to maximise carryover payments.[36]

The EBSS also requires that opex forecast must include any necessary adjustments for changes in responsibilities that result from compliance with a new or amended law or licence, or other statutory or regulatory requirements.[37]

14.4.4 Other issues

Victorian DNSP regulatory proposals

United Energy submitted that because its proposed operating expenditure already reflects substantial efficiency gains, it should not be penalised in the event that it cannot achieve these claimed savings. United Energy noted that it is planning to deliver significant efficiency gains compared to a projection of the status quo and that it would be inappropriate if it were to be penalised for failing to deliver the ambitious profile of cost savings that is reflected in its opex forecasts.[38] United Energy proposed two remedies to address this issue:[39]

- For the purposes of the EBSS, UED's forecast operating expenditure should be profiled to reflect the average of the forecast over the 5 year period. Therefore, the forecast operating expenditure for the purposes of the EBSS should be $120.4 million (in 2010 dollars) for each year in the forthcoming regulatory period; and

- If UED's total operating expenditure over the forthcoming regulatory period does not exceed the forecast of $601.8 million, then no EBSS penalties should apply.

United Energy considered that this proposed approach would ensure that the concept of 'fair sharing' of efficiency gains is properly reflected in the operation of the EBSS.

AER considerations

The AER notes United Energy's proposed approach to the treatment of efficiency gains and losses for the purposes of the EBSS in the forthcoming regulatory control period. The AER considers that the EBSS provides for the fair sharing of efficiency

36 AER, *Electricity DNSPs Efficiency benefit sharing scheme*, June 2008, p. 7.
37 ibid.
38 United Energy, *Regulatory proposal*, p. 219.
39 ibid., pp. 219–220.

gains between a DNSP and its customers. Where a DNSP's actual opex is less than the forecast opex, the DNSP retains the savings from this underspending within the regulatory control period. Following this, the benefits are then transferred to customers in the following and subsequent regulatory control periods through lower levels of forecast opex and therefore lower prices for customers.

The AER notes that United Energy's opex forecasts for the forthcoming regulatory control period reflect the outcomes of United Energy's business restructuring and competitive tender processes, which it considers will deliver significant efficiency gains over time. The AER encourages DNSPs to develop and implement business processes to bring about efficiency gains which benefit customers through lower prices and better service performance. However, the AER does not support United Energy's approach to the treatment of efficiency gains and losses over the forthcoming regulatory control period.

The AER does not consider that United Energy's proposal to use the average of United Energy's forecast operating expenditure amounts ($120.4 million) for each year of the forthcoming regulatory control period to calculate carryover amounts would provide for a fair sharing of efficiency gains between United Energy and its customers. The AER notes that, under this proposal, if United Energy's actual opex in the forthcoming regulatory control period is exactly as forecast then it would receive an efficiency carryover amount of $7.3 million ($2010). Furthermore, if United Energy were to make efficiency gains (or losses) in the forthcoming regulatory control period the total carryover payments it would receive would be $7.3 million ($2010) greater than the amounts it would receive if forecasts (not the average) were used to calculate carryover payments. The AER does not consider that this would be consistent with the requirements of clause 6.5.8(c) of the NER.

The AER considers that continuous incentives are crucial throughout the regulatory control period if the EBSS is to encourage DNSPS to reveal their efficient opex. The AER notes that when a DNSP either makes a one-off reduction to opex, an ongoing reduction to opex, or shifts costs between years, the benefit (or penalty) of doing so is the same irrespective of the regulatory year in which the change occurs. Furthermore, the benefit (or penalty) is shared between DNSPs and distribution network users according to the sharing ratio.[40]

AER modelling of the EBSS also highlights that the application of both positive and negative carryovers is necessary for the scheme to provide a constant incentive to improve efficiency. Without the application of these incentives, DNSPs would have a significant incentive to shift opex into the base year of the regulatory control period in order to increase its forecasts for the following regulatory control period. It follows that in the absence of applying both positive and negative carryovers, the EBSS would not in practice provide a DNSP with the incentive to reveal its efficient costs.[41]

Consequently, the AER considers that not applying negative carryovers if United Energy's total actual opex does not exceed the forecast of $601.8 million would not provide United Energy with a constant incentive to reduce opex. In

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40 AER, *Electricity DNSPs EBSS*, Final decision, June 2008, p. 19.
41 ibid, p. 20.

particular, under this proposal, if United Energy’s total actual opex were likely to be less than the total forecast opex then it would have an incentive to shift opex into the base year of the regulatory control period in order to increase its forecasts for the following regulatory control period. The AER does not consider that this would be consistent with the requirements of clause 6.5.8(c) of the NER.

14.5 AER conclusion

In accordance with cl. 6.12.1(9) of the NER, the AER's decision on how the EBSS will apply is as follows. The AER's decision on the application of the EBSS can also be found in the determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

The AER will apply the EBSS to the five Victorian DNSPs in accordance with its Framework and approach paper published in May 2009. The AER notes that none of the five Victorian DNSPs have proposed any changes to their capitalisation policies for the 2011–2015 regulatory control period. Should any of the Victorian DNSPs change their capitalisation policies during the forthcoming regulatory control period the AER will adjust the forecast opex amounts used to calculate carryovers to ensure consistency with the capitalisation policy used to calculate actual opex amounts.

The AER will also allow adjustments to EBSS calculations for the consequences of changes in growth for these DNSPs for the forthcoming regulatory control period. The AER considers that the growth adjustment should be consistent with the method used to escalate opex for forecast network growth in this draft decision in appendix J. Consequently, for the purposes of calculating efficiency carryover amounts, forecast opex will be adjusted for the actual growth in line length, the number of distribution transformers and zone substations, and customer numbers experienced over the forthcoming regulatory control period.

In accordance with section 2.3.2 of the EBSS, the AER considers superannuation costs for defined benefits and retirement schemes to be uncontrollable and consequently excludes these costs form the operation of the EBSS for the next regulatory period for all of the Victorian DNSPs.

Further, the AER considers the DMIA to be opex spent on non-network alternatives and consequently excludes these costs from the EBSS for the next regulatory period for all of the Victorian DNSPs, in accordance with section 2.3.2 of the EBSS.

In addition, in order to meet the requirements set out in clause 6.5.8(c)(2) of the NER in implementing the EBSS, the AER will exclude the following cost categories from the operation of the EBSS in the forthcoming regulatory control period. Specifically, the exclusion of these cost categories will provide the Victorian DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure:

- debt raising costs
- self insurance costs
- GSL payments.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS.[42]

The AER's controllable opex forecasts for the Victorian DNSPs are outlined in tables 14.1 to 14.5 and will be used to calculate efficiency gains and losses for the forthcoming regulatory control period, subject to adjustments required by the EBSS.[43] The derivations of the AER's controllable opex forecasts for the Victorian DNSPs are outlined in chapter 7 of this draft decision.

Table 14.1 AER conclusion on CitiPower's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	35.80	35.83	36.58	37.94	38.24	184.40
Adjustment for debt raising costs	–0.70	–0.73	–0.76	–0.79	–0.81	–3.79
Adjustment for self insurance	–	–	–	–	–	–
Adjustment for superannuation[a]	–	–	–	–	–	–
Adjustment for non-network alternatives[a]	–	–	–	–	–	–
Adjustment for DMIA	–0.20	–0.20	–0.20	–0.20	–0.20	–1.00
Adjustment for GSL payments	–0.02	–0.02	–0.02	–0.02	–0.02	–0.08
Forecast opex for EBSS purposes	**34.88**	**34.88**	**35.60**	**36.94**	**37.22**	**179.53**

Note: Totals may not add up due to rounding.

(a) In its regulatory proposal CitiPower did not provide sufficient information to identify the amount of opex expended on non-network alternatives and superannuation in the base year. Consequently the AER has been unable to determine the level of opex included in CitiPower's opex allowance for these costs. This amount will be identified in the AER's final decision.

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42 AER, *Electricity DNSPs EBSS*, Final decision, June 2008, pp. 6–7

43 ibid., pp. 5–7.

Table 14.2 AER conclusion on Powercor's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	119.92	121.18	123.35	128.22	129.59	622.26
Adjustment for debt raising costs	–1.17	–1.22	–1.26	–1.30	–1.35	–6.30
Adjustment for self insurance	–	–	–	–	–	–
Adjustment for superannuation[a]	–	–	–	–	–	–
Adjustment for non-network alternatives[a]	–	–	–	–	–	–
Adjustment for DMIA	–0.60	–0.60	–0.60	–0.60	–0.60	–3.00
Adjustment for GSL payments	–1.18	–1.18	–1.18	–1.18	–1.18	–5.88
Forecast opex for EBSS purposes	**116.97**	**118.18**	**120.31**	**125.14**	**126.47**	**607.07**

Note: Totals may not add up due to rounding.
(a) In its regulatory proposal Powercor did not provide sufficient information to identify the amount of opex expended on non-network alternatives and superannuation in the base year. Consequently the AER has been unable to determine the level of opex included in Powercor's opex allowance for these costs. This amount will be identified in the AER's final decision.

Table 14.3 AER conclusion on Jemena's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	47.69	47.92	48.35	51.51	51.03	246.51
Adjustment for debt raising costs	–0.43	–0.43	–0.44	–0.45	–0.46	–2.21
Adjustment for self insurance	–0.10	–0.10	–0.10	–0.10	–0.10	–0.52
Adjustment for superannuation[a]	–	–	–	–	–	–
Adjustment for non-network alternatives	–	–	–	–	–	–
Adjustment for DMIA	–0.20	–0.20	–0.20	–0.20	–0.20	–1.00
Adjustment for GSL payments	–0.02	–0.02	–0.02	–0.02	–0.02	–0.09
Forecast opex for EBSS purposes	**46.94**	**47.17**	**47.59**	**50.74**	**50.25**	**242.69**

Note: Totals may not add up due to rounding.
(a) In its regulatory proposal Jemena did not provide sufficient information to identify the amount of opex expended on non-network alternatives and superannuation in the base year. Consequently the AER has been unable to determine the level of opex included in Jemena's opex allowance for these costs. This amount will be identified in the AER's final decision.

Table 14.4 AER conclusion on SP AusNet's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	130.39	131.60	134.01	136.95	138.85	671.79
Adjustment for debt raising costs	–1.11	–1.14	–1.19	–1.23	–1.29	–5.96
Adjustment for self insurance	–	–	–	–	–	–
Adjustment for superannuation[a]	–	–	–	–	–	–
Adjustment for non-network alternatives[a]	–	–	–	–	–	–
Adjustment for DMIA	–0.60	–0.60	–0.60	–0.60	–0.60	–3.00
Adjustment for GSL payments	–4.34	–4.34	–4.34	–4.34	–4.34	–21.70
Forecast opex for EBSS purposes	**124.34**	**125.52**	**127.89**	**130.77**	**132.62**	**641.14**

Note: Totals may not add up due to rounding.

(a) In its regulatory proposal SP AusNet did not provide sufficient information to identify the amount of opex expended on non-network alternatives and superannuation in the base year. Consequently the AER has been unable to determine the level of opex included in SP AusNet's opex allowance for these costs. This amount will be identified in the AER’s final decision.

Table 14.5 AER conclusion on United Energy's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	90.53	91.09	92.38	95.43	95.91	465.34
Adjustment for debt raising costs	–0.75	–0.78	–0.80	–0.81	–0.82	–3.96
Adjustment for self insurance	–0.02	–0.02	–0.02	–0.02	–0.02	–0.12
Adjustment for superannuation[a]	–	–	–	–	–	–
Adjustment for non-network alternatives[a]	–	–	–	–	–	–
Adjustment for DMIA	–0.40	–0.40	–0.40	–0.40	–0.40	–2.00
Adjustment for GSL payments	–0.27	–0.27	–0.27	–0.27	–0.27	–1.33
Forecast opex for EBSS purposes	**89.08**	**89.62**	**90.89**	**93.93**	**94.40**	**457.92**

Note: Totals may not add up due to rounding.

(a) In its regulatory proposal United Energy did not provide sufficient information to identify the amount of opex expended on non-network alternatives and superannuation in the base year. Consequently the AER has been unable to determine the level of opex included in United Energy's opex allowance for these costs. This amount will be identified in the AER’s final decision.

15 Service target performance incentive scheme

15.1 Introduction

This chapter outlines the application of the AER's service target performance incentive scheme (STPIS) to the Victorian DNSPs in the 2011–15 regulatory control period.[1]

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

The STPIS establishes targets based on historical performance, and provides financial rewards for DNSPs exceeding performance targets and financial penalties for DNSPs failing to meet targets. The STPIS has two components, the S factor and the guaranteed service levels (GSL) scheme. The S factor component adjusts the revenue that a DNSP earns depending on reliability of supply and customer service performance. The GSL scheme sets threshold levels of service for DNSPs to achieve, and requires direct payments to customers who experience service worse than the predetermined level.

15.2 Regulatory requirements

Clause 6.6.2(a) of the National Electricity Rules (NER) requires that the AER publish an incentive scheme (the STPIS) to provide incentives for DNSPs to maintain and improve performance.

As part of developing the STPIS, clause 6.6.2 of the NER requires the AER to consult with authorities responsible for the administration of jurisdictional legislation and to ensure that service standards and targets do not put at risk a DNSP's ability to comply with jurisdictional service standards and targets.

Further, under clause 6.6.2(b)(3) of the NER, in developing and implementing the STPIS, the AER must take into account:

> (i) the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs; and

[1] The AER published its national distribution STPIS on 26 June 2008 (Version 01.0). On 8 May 2009, the AER published an amended STPIS (Version 01.1) to address issues regarding the interaction between the cap on revenue at risk and the equation for the calculation of the s–factor, and to clarify the operation of the scheme. On 25 November 2009, the AER published a further amended STPIS (Version 01.2) which primarily addressed how the Major Event Day (MED) boundary is calculated.

(ii) any regulatory obligation or requirement to which the DNSP is subject; and

(iii) the past performance of the distribution network; and

(iv) any other incentives available to the DNSP under the Rules or a relevant distribution determination; and

(v) the need to ensure that the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels; and

(vi) the willingness of the customer or end user to pay for improved performance in the delivery of services; and

(vii) the possible effects of the scheme on incentives for the implementation of non-network alternatives.

The NER states that the STPIS is to operate concurrently with any average or minimum service standards and GSL scheme that applies to a DNSP under jurisdictional electricity legislation.

The AER is required to publish a framework and approach paper prior to every distribution determination which sets out its likely approach to the application of the STPIS. Subject to clause 6.12.3 of the NER, the AER's Framework and approach paper is not binding on the AER or the DNSPs in relation to the application of the STPIS.

Under clause 2.1(d) of the STPIS, the AER is required to determine the following in accordance with the implementation of this scheme in a revenue determination:

(1) each applicable component and parameter to apply to a DNSP including the method of network segmentation for the reliability of supply component

(2) the revenue at risk to apply to each applicable component and parameter

(3) the incentive rate to apply to each applicable parameter including the value of customer reliability (VCR) to be applied in accordance with clause 3.2.2(d) and appendix B

(4) the performance target to apply to each applicable parameter in each regulatory year of the regulatory control period

(5) any decision with respect to the transitional arrangements set out in clause 2.6

(6) the threshold to apply to each applicable GSL parameter

(7) the payment amount to apply to the applicable GSL parameter

(8) the major event day boundary to apply to a DNSP:

   (i) where the DNSP has proposed a major event day boundary that is greater than 2.5 standard deviations from the mean; or

(ii) where the major event day boundary that applied to the DNSP in previous distribution determinations was greater than 2.5 standard deviations from the mean; or

(iii) where the DNSP has proposed a major event day boundary that is greater than 2.5 standard deviations from the mean and where in previous distribution determinations the major event day boundary that has applied to the DNSP was greater than 2.5 standard deviations from the mean.

The AER's conclusions addressing the requirements of clause 2.1(d) of the STPIS for each of the Victorian DNSPs are outlined in section 15.8 of this chapter.

15.3 AER framework and approach

The AER published its Framework and approach paper for the Victorian DNSPs in May 2009. The Framework and approach paper outlined the AER's likely approach to the application of the STPIS for the Victorian DNSPs with the intention of assisting the DNSPs in preparing their regulatory proposals.

The AER outlined in its Framework and approach paper that its likely approach was to apply the reliability of supply, customer service and GSL components of the STPIS —assuming the current Victorian jurisdictional GSL scheme is repealed—to the Victorian DNSPs in the 2011–15 regulatory control period.

The AER noted its intention to apply all of the reliability of supply parameters outlined in the STPIS. The proposed reliability of supply parameters are:

- unplanned system average interruption duration index (SAIDI)
- unplanned system average interruption frequency index (SAIFI)
- momentary average interruption frequency index (MAIFI).

In relation to the customer service component, the AER's likely approach was that the telephone answering parameter will apply to the Victorian DNSPs for the forthcoming regulatory control period. As the STPIS did not include any quality of supply parameters, none were proposed.

The AER noted that benefits and penalties accrued in the current regulatory control period under the Essential Services Commission of Victoria's (ESCV) S factor scheme should not be incorporated in the price cap formula. Rather, financial carryover amounts from the current regulatory control period should be included as a building block element in the calculation of allowed revenue in the forthcoming regulatory control period.

Targets for the reliability of supply component will be attached to SAIDI, SAIFI and MAIFI with separate targets for each segment of the network in accordance with the STPIS. Targets will reflect the available data on average performance over the previous five years, with adjustments as necessary under the STPIS.

The Framework and approach paper indicated that the AER's likely approach will be to apply the GSL scheme as set out in the STPIS. This position was based on advice given to the AER from the Department of Primary Industries (DPI) at the time, that the GSL scheme provided for in the *Electricity Distribution Code* (EDC) and the *Public Lighting Code* (PLC) would cease to apply at the end of the current regulatory control period.[2]

The GSL parameters in the STPIS are:

- frequency of interruptions (number of sustained interruptions experienced by a customer)
- streetlight repair (the repair of a public light within five businesses days)
- new connections (connection of electricity to a new premises on or before a date agreed by a customer)
- notice of planned interruptions
- duration of interruptions or total duration of interruptions (duration of unplanned interruptions experienced by a customer).

15.4 Amendments to the STPIS

In November 2009, after publishing the Framework and approach paper, the AER amended the STPIS to apply in the forthcoming regulatory control period for South Australia and Victoria. The key elements of the amendments were:

- allowing consideration of other statistical approaches for the calculation of the major event day threshold where the underlying data is not normally distributed
- allowing DNSPs to propose a major event day (MED) boundary of greater than 2.5 beta
- addressing a timing issue associated with the operation of the scheme in Victoria.[3]

Where previously the STPIS applied only to financial years, it now applies to regulatory years in line with the previous Victorian S factor scheme. This amendment ensures that there is not a period between the end of the ESCV's S factor scheme and the start of the STPIS where no incentive to improve performance will apply. Other amendments were also made to the scheme to further clarify the operation of the STPIS and to correct typographical errors.

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2 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, *May 2009*, p. 5.

3 AER, *Final Decision, Electricity DNSP, Service target performance incentive scheme*, p. 1.

15.5 Summary of Victorian DNSP regulatory proposals

This section provides a summary of how the five Victorian DNSPs proposed to apply the AER's STPIS over the forthcoming regulatory control period. It will focus on the areas where one or more DNSP has proposed to depart from the STPIS or the Framework and approach paper.

15.5.1 Reliability parameters

Tables 15.1–15.5 outline the Victorian DNSPs' most recent five years of historical reliability performance and proposed reliability parameter targets. Consistent with the STPIS, the DNSPs have removed the effects of transmission network outages and other up-stream events from this performance data. The Victorian DNSPs have also applied their proposed MED thresholds to the numbers, removing the effects of extreme weather events which are excluded by the STPIS.

The STPIS states that the target performance parameters for the 2011–15 regulatory control period are to be based on the average performance over the most recent five years of historical performance data. All the targets shown in tables 15.1–15.5 are based on this historical average. In a number of cases the proposed targets are not a straight average of performance over the five years from 2005–09. This is because a number of the DNSPs have proposed adjustments to the targets to account for factors that they believe will materially affect performance in the forthcoming regulatory control period. These proposed adjustments are discussed at section 15.7.9.

The Victorian DNSPs were required to submit their regulatory proposals on 30 November 2009. At this time, performance data for the whole of 2009 was not available and the DNSPs provided estimates of performance in 2009. In February 2010 the Victorian DNSPs submitted updated performance targets incorporating actual performance in 2009. Tables 15.1–15.5 present these updated performance targets.

Table 15.1 CitiPower proposal—historical reliability performance and proposed targets

	2005	2006	2007	2008	2009	2011–15 proposed targets
SAIDI (average minutes)						
CBD	12.00	13.91	6.94	6.11	17.40	11.27
Urban	18.22	23.59	23.55	18.75	27.69	22.36
SAIFI (average interruptions)						
CBD	0.173	0.265	0.144	0.090	0.259	0.186
Urban	0.386	0.461	0.521	0.352	0.531	0.450
MAIFI (average interruptions)						
CBD	0.008	0.026	0.021	0.00	0.074	0.026
Urban	0.17	0.167	0.16	0.16	0.215	0.0175

Source: CitiPower, email, 25 March 2010.

Table 15.2 Powercor proposal—historical reliability performance and proposed targets

	2005	2006	2007	2008	2009	2011–15 proposed targets
SAIDI (average minutes)						
Urban	67.55	73.64	93.57	93.38	136.40	92.91
Short rural	99.09	125.84	144.05	107.66	163.12	127.95
Long rural	269.06	244.73	240.40	212.43	383.92	270.12
SAIFI (average interruptions)						
Urban	1.191	1.434	1.163	1.397	1.594	1.356
Short rural	1.365	1.972	1.859	1.441	1.774	1.682
Long rural	2.962	2.827	2.659	2.092	3.143	2.737
MAIFI (average interruptions)						
Urban	1.602	1.501	1.396	1.513	1.344	1.471
Short rural	3.405	2.305	2.935	2.952	3.150	2.950
Long rural	9.002	5.921	7.332	5.977	5.561	6.758

Source: Powercor, email, 25 March 2010.

Table 15.3 Jemena proposal—historical reliability performance and proposed targets

	2005	2006	2007	2008	2009	2011–15 proposed targets
SAIDI (average minutes)						
Urban	53.30	86.78	57.43	61.37	72.68	66.31
Short rural	224.47	134.44	175.58	97.75	133.51	153.15
SAIFI (average interruptions)						
Urban	1.107	1.317	1.043	0.938	1.154	1.112
Short rural	3.091	1.910	4.197	1.436	2.307	2.588
MAIFI (average interruptions)						
Urban	0.733	0.916	0.699	0.589	0.925	0.828
Short rural	0.884	1.784	2.993	1.577	2.462	2.287

Source: Jemena, email, 19 March 2010.

Table 15.4 SP AusNet proposal—historical reliability performance and proposed targets

	2005	2006	2007	2008	2009	2011–15 proposed targets
SAIDI (average minutes)						
Urban	101.48	160.39	133.34	74.18	109.52	121.36
Short rural	224.15	227.54	245.65	149.73	327.84	246.3
Long rural	349.57	326.94	308.17	216.99	326.96	320.46
SAIFI (average interruptions)						
Urban	1.62	2.15	1.67	0.98	1.55	1.67
Short rural	2.64	2.91	2.83	2.19	3.62	2.97
Long rural	3.57	3.54	3.85	3.29	3.67	3.76
MAIFI (average interruptions)						
Urban	3.03	2.72	2.77	2.21	2.09	2.69
Short rural	5.26	4.97	5.48	5.63	6.69	5.88
Long rural	9.58	7.70	9.87	8.99	10.95	9.87

Source: SP AusNet, email, 15 March 2010.

Table 15.5 United Energy proposal—historical reliability performance and proposed targets

	2005	2006	2007	2008	2009	2011–15 proposed targets
SAIDI (average minutes)						
Urban	49.59	47.44	54.21	50.38	63.68	53.06
Short rural	79.47	67.06	80.96	77.64	189.18	98.86
SAIFI (average interruptions)						
Urban	0.828	0.815	0.918	0.840	1.006	0.881
Short rural	1.677	1.480	1.355	1.455	2.722	1.738
MAIFI (average interruptions)						
Urban	1.314	1.105	0.967	0.941	1.013	1.068
Short rural	2.815	1.476	1.610	2.060	2.609	2.114

Source: United Energy, email, 22 March 2010.

15.5.2 Customer service parameters

The only customer service parameter proposed in the Framework and approach paper was the telephone answering parameter. The following table sets out the Victorian DNSPs' historical telephone answering performance and their proposed targets for the forthcoming regulatory control period.

Table 15.6 Victorian DNSPs—historical customer service performance and proposed targets (per cent)

Calls answered within 30 seconds	2005	2006	2007	2008	2009	2011–15 proposed targets
CitiPower	89.15	85.53	87.07	87.70	79.62	86.00
Powercor	88.73	86.53	89.28	89.84	85.71	88.00
Jemena	74.00	76.00	73.00	61.00	65.00	63.00
SP AusNet	82.70	92.20	91.16	92.3	92.00	90.08
United Energy	69.07	65.23	65.31	63.62	62.53	65.15

Source: CitiPower, Jemena, Powercor, SP AusNet and United Energy regulatory proposals.

15.5.3 Guaranteed service level parameters

The Victorian DNSPs were requested to provide forecast GSL payments under the STPIS as part of their regulatory proposals. Table 15.7 to Table 15.9 provide an outline of the forecast GSL payments proposed by the Victorian DNSPs. The regulatory proposals of CitiPower, Powercor and SP AusNet provided forecasts of GSL payments under the STPIS. Jemena provided forecast performance under the STPIS, but only forecast performance for GSL parameters that did not change between the STPIS and Victorian GSL scheme. United Energy proposed to apply the Victorian GSL parameters for the 2011–15 regulatory control period and forecast its GSL payments based on this proposal.[4]

Table 15.7 CitiPower, Powercor and Jemena —proposed GSL targets

AER GSL parameter	Proposed GSL targets (total number of payments)		
	CitiPower	Jemena	Powercor
9 interruptions (CBD, Urban)	–	–	1 240
15 interruptions (rural)	–	–	100
12 hours of interruptions (CBD/Urban)	–	–	3 400
18 hours of interruptions (Rural)	–	–	3 242
20 hours of sustained interruptions	2	142	6 043
30 hours of sustained interruptions	–	3	1 237
60 hours of sustained interruptions	–	–	1
Failure to repair streetlights within 5 days	23	–	34
Failure to connect on or before the agreed date	23	55	12
4 days notice for planned interruptions	–	–	294

Source: CitiPower, Jemena, Powercor regulatory proposals.

4 United Energy, *Regulatory Proposal for Distribution Prices and Services, January 2011–December 2015*, November 2009—appendix A3, RIN templates 6.6, confidential, 30 November 2009, p. 2.

SP AusNet's proposed forecast GSL payments were escalated in line with forecast growth in customer numbers over the regulatory control period. SP AusNet's forecasts for GSL payments are shown in table 15.8.

Table 15.8 SP AusNet—proposed GSL targets

AER GSL parameter	Proposed GSL targets (total number of payments)				
	2011	2012	2013	2014	2015
9 interruptions (CBD, Urban)	1 709	1 740	1 767	1 793	1 821
15 interruptions (rural)	1 813	1 842	1 868	1 892	1 919
12 hours of interruptions (CBD/Urban)	7 364	7 496	7 613	7 723	7 846
18 hours of interruptions (Rural)	18 337	18 635	18 897	19 142	19 411
20 hours of sustained interruptions	11 019	11 205	11 368	11 522	11 691
30 hours of sustained interruptions	4 574	4 651	4 719	4 783	4 853
60 hours of sustained interruptions	321	326	331	336	361
Failure to repair streetlights within 5 days	2.3	2.3	2.3	2.3	2.3
Failure to connect on or before the agreed date	278	263	231	217	239
4 days notice for planned interruptions	292	297	301	306	310

Source: SP AusNet, *Regulatory proposal*.

Table 15.9 United Energy—proposed GSL targets

Victorian GSL parameter	Proposed GSL targets (total number of payments)
24 momentary interruptions	–
36 momentary interruptions	–
10 hours of sustained interruptions	60
15 hours of sustained interruptions	–
30 hours of sustained interruptions	–
15 minutes late for appointments	24
Failure to repair streetlights in agreed timeframe	28
Failure to connect on the agreed date	86
More than 20 hours of sustained interruptions	523
More than 30 hours of sustained interruptions	216
More than 60 hours of sustained interruptions	34

Notes: Forecasts based on existing ESCV GSL scheme parameters.
Source: United Energy, *Regulatory proposal*.

15.5.4 Variations to the STPIS

In certain circumstances, a DNSP may propose to vary the application of the STPIS. Clause 2.5 of the STPIS requires a DNSP to demonstrate that the variation is consistent with both clause 6.6.2(b)(3) of the NER and the objectives of the scheme. The following section outlines the key variations proposed by the Victorian DNSPs in their regulatory proposals.

Definition of MAIFI

All the Victorian DNSPs proposed to use the definition of MAIFI that applied under the ESCV's S factor scheme rather than the definition in the STPIS. Under the AER's definition of MAIFI, each operation of an automatic reclose device is counted as a separate interruption. Under the ESCV's S factor scheme however, each sequence of an auto-reclose attempt that results in a successful auto-reclose is counted as a single momentary outage if the sequence is completed in less than one minute.

The Victorian DNSPs argued that information collected under the ESCV's definition of MAIFI is the only information available upon which the AER can reasonably base performance and derive future MAIFI targets.[5] CitiPower and Powercor also stated that the application of the AER's MAIFI definition under the STPIS could disadvantage DNSPs which deploy automated smart network technologies. CitiPower

[5] CitiPower, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 264; Powercor, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 270.

and Powercor considered that the proposed change accords with clause 2.6 of the AER's STPIS on the basis that the change is required to address a transitional issue arising from the differing definitions.[6]

Further, Jemena also proposed that the event definition should be modified from a 1 minute period to a 5 minute period.[7]

Network reliability parameters

CitiPower and Powercor noted that clause 3.2.1(a) of the STPIS allows modifications to the reliability performance targets, however they did not consider that any modifications are required to the average reliability performance in accordance with clause 3.2.1(a)(1) of the STPIS, as:

> the reliability improvements realised from the previous and current regulatory control period works programs were not funded through revenue allowed under the applicable distribution determinations; and
>
> the proposed capital and operating expenditure works programs for the next regulatory control period detailed in Chapters 5 and 6 of this Regulatory Proposal does not fund reliability and quality improvements.[8]

CitiPower and Powercor also submitted that no adjustment was necessary pursuant to clause 3.2.1(a)(1A) as the clause:

> …does not contemplate the making of adjustments for the first regulatory control period. In any event, CitiPower's historic reliability performance is consistent with the performance targets set by the ESCV and hence no adjustment is necessary.[9]

CitiPower also submitted that it did not expect any other factors to materially affect network reliability performance pursuant to clause 3.2.1(a)(2).

Modifications to reliability targets

The Victorian DNSPs proposed the following adjustments to the calculation of the reliability parameters:

- all the Victorian DNSPs indicated in their regulatory proposals their intent to update their reliability targets to reflect 2009 actual performance data, which they submitted to the AER in March to be incorporated into the AER's draft decision

- impact of climate change—SP AusNet and United Energy proposed to adjust their reliability targets to account for a projected change in environmental factors that they claim will affect network performance during the forthcoming regulatory control period

- Jemena proposed an adjustment to its forecast MAIFI targets due to climate change

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6 ibid.
7 Jemena, *Regulatory Proposal 2011–2015*, 30 November 2009, p. 197.
8 CitiPower, *Regulatory proposal* p. 268; Powercor, *Regulatory proposal* p. 274.
9 ibid.

- United Energy proposed to adjust its targets for the effects of probabilistic planning, changes in the approach taken to forecast electricity demand and the secondary effects of the drought.

Revenue at risk

CitiPower and Powercor proposed a 5 per cent cap on revenue at risk in line with the default cap specified in the STPIS and the Framework and approach paper.[10] Jemena did not make reference to the cap on revenue at risk in its regulatory proposal. SP AusNet and United Energy, proposed to deviate from the default cap of 5 per cent as set out in the AER's Framework and approach paper.

SP AusNet proposed that no cap be applied to the reliability component of the STPIS,[11] while United Energy proposed a lower cap of 3 per cent.[12]

Major event day (MED) threshold

There are several differences in how the Victorian DNSPs have calculated the MED threshold. A significant area where some DNSPs have sought to deviate from the default STPIS in their proposals is to apply different beta values in calculating the MED threshold. SP AusNet proposed a MED threshold of 3.2 beta from the mean and Powercor proposed a MED threshold of 3.1 beta from the mean.[13]

SP AusNet stated that a MED threshold of 3.2 beta from the mean is appropriate as it would ensure that only extreme events were excluded from its reliability performance figures and that it would better align the scheme with the national electricity objective.[14]

Powercor considered that a 3.1 beta from the mean MED threshold would ensure that expenditure efficiencies are not pursued at the expense of day-to-day system reliability. Powercor also stated that a 3.1 beta from the mean would provide Powercor with a stronger incentive to improve performance.[15]

Application of the GSL component of the STPIS

There were several differences among how the Victorian DNSPs proposed to forecast GSL payments in the forthcoming regulatory control period. One source of difference was that forecast payments were either based on the current ESCV GSL scheme or the

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10 CitiPower, *Regulatory proposal* p. 261; Powercor, *Regulatory proposal* p. 266.
11 SP AusNet, *Regulatory proposal* p. 54.
12 United Energy, *Regulatory proposal* p. 211.
13 Outlier performance (for example, due to extreme weather or events) is generally excluded using the 2.5 beta method described in the US Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003. This method calculates a Major Event Day (MED) threshold which is 2.5 standard deviations (beta) from the mean. Events which are more than 2.5 beta from the daily SAIDI mean are excluded from the calculation of the SAIDI target and the DNSP's performance. The AER has amended the scheme to allow a DNSP to propose a major event day boundary that is greater than the 2.5 beta that is currently permitted.
14 SP AusNet, *Electricity Distribution Price Review, Regulatory proposal,* November 2009, p. 57.
15 Powercor, *Regulatory proposal* p. 268.

GSL component of the STPIS. Jemena requested an exemption from the AER's notice of planned interruptions GSL parameter.[16]

ESCV S factor scheme true-up

CitiPower, Jemena, Powercor and SP AusNet proposed to close out the ESCV's S factor payments through an adjustment to the opex building block as foreshadowed in the AER's Framework and approach paper. United Energy proposed to apply the S factor calculated under the ESCV scheme to the price formula in 2011, using a modified method from 2012 onwards. All the Victorian DNSPs proposed a further true-up in 2012 to account for the 2010 actual performance which will not be known until after March 2011.

15.6 Summary of submissions

The AER received seven submissions regarding the STPIS. The AER notes that a number of the submissions related to the development and not the application of the STPIS. The AER considers that it is appropriate for submissions regarding the development of the STPIS to be addressed as part of any future review of the STPIS and not as part of the Victorian 2011–15 distribution determinations.

15.6.1 Relationship between actual expenditure and the STPIS

The Energy Users Coalition of Victoria (EUCV) expressed support for a financial incentive to encourage better service performance but submitted that:

> all DNSPs comment that much of the capex is based on achieving reliability of supply, yet the STPIS targets suggested by them tend to be less than the reliability actually achieved in 2006–10, with significantly less capex being used in the current period. The EUCV questions how DNSPs justify providing a lesser reliability while simultaneously proposing more capex.[17]

The EUCV also commented that, in regard to bush fire mitigation, it is not appropriate for consumers to pay DNSPs a bonus for an under-run on opex under the STPIS in the current regulatory control period, and then pay higher opex, if for example poor inspection practices contributed to the severity of the impact.[18]

15.6.2 Revenue at risk

The Total Environment Centre (TEC) submitted that as it considered a DNSP's management is committed to short term rewards, business incentives act as a disincentive to achieving long term service performance of the network, which is compounded in practice by the rewards for service performance being limited by the regulatory guideline to 1 per cent of allowed revenue, although the NER allows this constraint to be as high as 5 per cent.[19]

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16 Jemena, *Regulatory proposal* p. 201-202.

17 Energy Users Coalition of Victoria, *Victorian Electricity Distribution Revenue Reset,* February 2010,p. 26.

18 EUCV, *Submission to the AER,* February 2010, p. 53.

19 Total Environment Centre, *Submission to the AER on Victorian DNSPs' regulatory proposals,* February 2010 Attachment A, p.35,36.

The TEC also stated that the 1 per cent constraint against revenue must be increased to overcome the business' financial performance incentive. It noted that this would provide for much higher reward for reducing capex and opex. One way to achieve this is for a DNSP to pay a consumer for non-supply the same amount the consumer would pay if the supply was provided.[20]

TRUenergy stated that it supports the revised S factor scheme to be applied by the AER in the forthcoming regulatory control period. In particular, TRUenergy noted that the total S factor revenue that a DNSP is able to achieve is capped at 5 per cent of its total regulated revenue, whereas the ESCV's uncapped scheme could result in large network tariff fluctuations.[21]

15.6.3 Incentive rates

The EUCV submitted that when the Essential Services Commission of South Australia (ESCOSA) undertook a review of the willingness to pay for increased reliability it found that, in South Australia, there was not a general willingness to pay for increased reliability.[22] Additionally, it considered that if the current approach to service performance is to be continued, the acceptable level of unserved energy should be addressed. The EUCV also questioned whether the value of customer reliability (VCR) at $55k/MWh is economically efficient.[23]

The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria (the Minister) submitted that the AER should review the incentive rates of the STPIS based on the latest VCR.[24]

Both the Minister[25] and the Consumer Utilities Advocacy Centre[26] considered that incentives must ensure the benefits from services received outweigh or be commensurate to the costs.

The EUCV posited that services should improve with increased payments.[27]

15.6.4 Transitional arrangements

The EUCV proposed that the DNSPs' calculations to convert from the ESCV’s S factor to the AER’s STPIS need to be verified.[28] It also noted that DNSPs have proposed variations to the AER's STPIS including proposals to alter MAIFI. The EUCV considered that variations to the standard STPIS should be minimal.[29]

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20 ibid.
21 TRUenergy, *submissions on SP AusNet, Powercor and United Energy regulatory proposals,* 16 April 2010, p. 3.
22 EUCV, *Submission to the AER*, p. 66.
23 EUCV, *Submission to the AER*, p. 27.
24 Minister for Energy and Resources, *Submission on the Victorian DNSPs regulatory proposals for 2011-2015*, pp. 7- 8.
25 ibid., p. 3.
26 Consumer Utilities Advocacy Centre, *Response to the Victorian distribution businesses regulatory proposals* 17 February 2010, p. 5.
27 EUCV, *Submission to the AER*, p. 65.
28 ibid., p. 67.
29 ibid., p. 62.

15.6.5 Guaranteed service levels

The Minister submitted that, as part of the Victorian determination, the AER should review whether the GSL payment thresholds should be amended to ensure that the payments continue to be made to the worst served 1 per cent of customers. The Minister also considered that the AER should review whether the level of GSL payments should be amended to reflect the latest VCR.[30]

15.6.6 STPIS targets

The EUCV submitted that the DNSPs' forecast reliability targets for 2009 are higher than the 2005–09 average. When excluding the 2009 data, the service performance trends of the DNSPs are downwards sloping (indicating an improvement in service). Therefore, the EUCV considered that the AER should set STPIS targets to reflect the trend in performance rather than applying the arithmetic average.[31]

The EUCV also submitted that the STPIS targets should be challenging—perhaps 10 per cent lower than the calculations might indicate—and that there should be no bonus for achieving average performance.[32]

The Minister considered that the 2011 targets should be based upon the actual performance of 2010 otherwise customers may pay for improvements in reliability which they have already effectively paid for, or DNSPs may be penalised for deterioration in reliability for which they would have been already penalised.[33]

The Minister also considered that as part of its determination, the AER should review the target levels of reliability experienced by the worst served 15 per cent of customers and the thresholds for reporting low reliability feeders.[34]

The Australian Industry Group (Ai Group) noted that it had anecdotal information from member companies that 'short duration' interruptions to supply can cause costly loss of production time, and operational costs resulting from the outage. Ai Group also noted that the MAIFI index covers interruptions by an average customer, and submitted that the performance index should also consider localised areas of the distribution network in order to diagnose and rectify problem areas within the network.[35]

15.6.7 Impact of STPIS on demand management

The TEC noted that a side effect of the STPIS is that it discourages demand management solutions.[36] Similarly, CUAC raised a concern that the STPIS

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30 Minister for Energy and Resources, *Submission to the AER*, p. 7.
31 EUCV, *Submission to the AER*, February 2010, pp. 63-65.
32 ibid., p. 67.
33 Minister for Energy and Resources, *Submission to the AER*, pp. 7- 8.
34 ibid., p. 7.
35 Australian Industry Group, *Preliminary response to AER review of electricity network service proposals Victoria*, p. 4.
36 TEC, *Submission to the AER*, Attachment A, p. 14.

encourages network investment over non-network alternatives even if non-network solutions may be more efficient.[37]

15.6.8 Other issues

The Victorian Council of Social Services (VCOSS) noted that the AER should provide a supplementary report to its draft decision which should include information on service performance by geographical area.[38]

The EUCV submitted that the AER should continue the ESCV's assessment of the worst performing feeders with the goal of bringing all feeders to the same level.[39]

The Minister questioned whether the quality of supply data that has been provided since the last price determination enables additional targets to be set for quality of supply.[40]

Ai Group noted that DNSPs have modelled reductions of energy usage for non-peak periods. Ai Group questioned the consequences to system reliability and quality of supply and pricing if the rate of implementation of efficiency gains is slower than predicted by the DNSPs' models.[41]

The AER acknowledges the Minister's and other stakeholders' concerns regarding performance monitoring, in particular the experience of customers in the worst served areas of each DNSP's network. The AER intends to enhance the monitoring of the Victorian DNSPs' performance in the forthcoming regulatory control period. Details of the AER's proposed performance monitoring framework are explained in chapter 21 of this draft decision.

15.7 Issues and AER considerations

The following section sets out the AER's considerations in applying its STPIS to the Victorian DNSPs for the 2011–15 regulatory control period, having regard to the requirements of clause 2.1(d) of the STPIS and in making its constituent decision pursuant to clause 6.12.1(9) of the NER.

15.7.1 Historical performance data

Framework and approach

The Framework and approach paper proposed basing performance targets on the five most recent years of audited annual performance data. In the Framework and approach paper this was envisaged to be data from the regulatory years 2004–08 (inclusive).[42]

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[37] CUAC, *Submission to the AER*, p. 5.
[38] Victorian Council of Social Services, *Victorian electricity distribution network service providers' regulatory proposals*, 16 February 2010, p. 2.
[39] EUCV, *Submission to the AER*, p. 65.
[40] Minister for Energy and Resources, *Submission to the AER*, p. 7.
[41] Australian Industry Group, *Submission to the AER*, p. 2.
[42] AER, *Framework and approach paper*, May 2009, p. 95.

Victorian DNSP regulatory proposals

The Victorian DNSPs proposed that the 2005–09 performance data represents the most recent audited performance data and should therefore be used as the basis of the forecast service performance targets. Following the submission of their regulatory proposals, the Victorian DNSPs provided updated data and proposed targets in March 2010 which incorporated actual audited 2009 data. Table 15.1–15.5 outline the Victorian DNSPs' five years of historical performance (2005–09) on which their proposed performance targets are based.

AER considerations

The AER considers that as the most recent data is desirable and is consistent with the STPIS, it is appropriate to use historical data from 2005–09 calendar years instead of 2004–08 to forecast service performance.

15.7.2 Applicable components and parameters

Framework and approach

The Framework and approach paper stated that the AER's likely approach was to apply the SAIDI, SAIFI and MAIFI reliability of supply parameters attaching targets to each of the SCONRRR feeder types as set out in the STPIS, and the telephone answering customer service parameter.[43]

Victorian DNSP regulatory proposals

Except for Powercor, Victorian DNSPs proposed to apply the reliability and customer service parameters as set out in the Framework and approach paper. Powercor sought to segment its network area by urban and rural network type, rather than by urban, short rural and long rural network types as identified by the STPIS.[44]

Powercor proposed the modification to network segmentation because it considered that the methodology of allocating the average energy consumption between short rural and long rural feeders is imprecise. As a consequence, it considered that dividing the rural segment between short rural and long rural feeders could potentially result in incentives being distorted and undue weight given to one or other network type.[45]

Powercor considered that the modification to feeder types will ensure a better targeted incentive scheme and eliminate the potential for the distortions mentioned above.[46]

AER considerations

The AER intends to apply the feeder categories, as set out in the STPIS, for all the Victorian DNSPs to measure reliability performance. This was noted in the Framework and approach paper and is set out at appendix A of the STPIS.

Pursuant to clause 3.1(d) of the STPIS, Powercor has proposed an alternative segmentation of the network—that is to combine the short rural and long rural

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43 ibid., p. 5.
44 Powercor, *Regulatory proposal* p. 267.
45 ibid., p. 269.
46 ibid.

network segments. Clause 3.1(d) stipulates that the network area may be segmented by a method other than by network type if the alternative method better meets the objectives of the scheme.

The STPIS outlines that the first step in calculating the incentive rate for unplanned SAIDI and unplanned SAIFI is to multiply the portion of the VCR assigned to the relevant parameter by the average annual energy consumption by network type expected for the regulatory control period.

The AER notes that allocating average energy consumption between short rural and long rural feeders does not necessarily result in each feeder having a deemed energy consumption equal to actual energy consumption, as submitted by Powercor. However, the AER considers that, for the reasons outlined below, on average, the short rural and long rural feeders will receive a more accurate weighting than if there is not a distinction between the two feeder types.

The AER has reviewed the information submitted by Powercor and is aware that Powercor services approximately 245 000 short rural supply points and 204 000 long rural supply points.[47] The total energy consumption of short rural customers is approximately 3 233 GWh, and 3 460 GWh for long rural customers[48] meaning that fewer long rural customers appear to consume more electricity than short rural customers. As such, in Powercor’s distribution network, long rural customers receive a higher incentive rate weighting than short rural customers.

Under the STPIS, through the calculation of SAIDI, SAIFI and MAIFI the reliability of supply targets are weighted for customer numbers and not energy consumption.[49] This provides Powercor with an incentive to improve supply reliability to the greatest number of customers. By segmenting the network by network type, the STPIS also provides incentives to improve supply reliability based on the relative amount of electricity consumption by network segment.

The AER considers that combining the long rural and short rural feeder types will result in a lower incentive (than the status quo) for Powercor to improve reliability for long rural customers, who consume more electricity and are similar in number to short rural customers.

The AER is concerned that without a distinction between long rural and short rural feeders, Powercor may have the incentive to focus on improving reliability of supply on the feeder type which presents the lowest cost per unit increase in reliability based on customer numbers, without having regard to the amount of energy, on average, the feeder type supplies. This is not consistent with the characteristics of the STPIS.

The AER's analysis shows that the effect of combining the two feeder types for consumers previously on short rural feeders will be to increase both the supply reliability target levels (make it relatively easier to achieve) and the relative weighting of the short rural feeder. Conversely, the effect on consumers previously on long rural

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47 Powercor, *2009 Regulatory Accounts*, confidential, 26 February 2010
48 ibid.
49 See Appendix A of the STPIS for the calculation of the reliability parameters.

feeders is to reduce both the supply reliability target levels (making it relatively harder to achieve) and the relative weighting of the long rural feeder. The AER is not satisfied that either of these effects will better benefit consumers or improve the incentive property of the STPIS.

Regarding submissions proposing to add a quality of supply parameter to the STPIS, the AER notes that currently the monitoring of supply quality covers limited areas of each DNSP's network,[50] Hence, the existing quality of supply data may not be suitable for the purpose of the STPIS. However, the AER notes that the Victorian Government has mandated a complete rollout of smart meters to replace all existing energy meters by 2013. The new smart meters will have the capability to monitor steady-state voltage as a factor of supply quality.[51] The AER will consider whether to include quality of supply as a performance measure when it reviews the STPIS in the future.

AER conclusion

The AER considers that Powercor has not sufficiently demonstrated that its proposed variation to the STPIS to retain only the urban feeder and rural feeder types will better meet the objectives of the scheme. Therefore, the AER proposes to apply the relevant feeder categories, as outlined at appendix A of the STPIS, to Powercor in the forthcoming regulatory control period. For all Victorian DNSPs, the AER will apply the SAIDI, SAIFI and MAIFI reliability of supply parameters and the telephone answering customer service parameter to the feeder types as set out in the STPIS.

In accordance with clause 4.1 of the STPIS the AER will not be applying a quality of supply parameter under the STPIS at this time.

15.7.3 Revenue at risk

Framework and approach

In the Framework and approach paper, the AER indicated that it will generally apply a default revenue at risk of ±5 per cent for all Victorian DNSPs as provided for under the STPIS. However, the AER noted that where a DNSP proposes an alternative cap on revenue at risk, the AER will assess whether or not to accept the proposal against the objectives specified at clause 1.5 of the STPIS.

The Framework and approach paper stated that:

> The issue of a revenue at risk cap was considered during consultation on the development of the STPIS and there was limited stakeholder support for a default uncapped revenue at risk under the STPIS. Stakeholders generally supported a cap on the revenue at risk under the STPIS. As a result, the

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[50] Refer AER, *Victorian Electricity Distribution Businesses, Comparative Performance Report 2008*, November 2009, p. 52. Currently, DNSPs monitor quality of supply at each zone substation and at the far end of one distribution feeder supplied from each zone substation. Under the 2006–10 EDPR, the two predominantly rural distributors, Powercor and SP AusNet, were funded to install additional sophisticated voltage monitoring equipment (27 locations for Powercor and 17 for SP AusNet).

[51] AER, *Victorian Electricity Distribution Businesses, Comparative Performance Report 2008*, November 2009, p. 52.

> default cap was introduced, with the flexibility under the STPIS to apply alternatives where appropriate. The AER considers that a cap on revenue at risk under the STPIS serves as a risk mitigation mechanism, especially for those DNSPs which have not been subject to a scheme like the STPIS previously.[52]

Victorian DNSPs regulatory proposals

CitiPower[53] and Powercor[54] proposed a 5 per cent cap on revenue at risk in line with the STPIS. Jemena did not make reference to the 5 per cent default cap on revenue at risk. Therefore, in the absence of evidence to depart from the default position, the AER intends to apply the default 5 per cent cap on revenue at risk to CitiPower, Powercor and Jemena.

SP AusNet and United Energy proposed to vary the default cap on the amount of revenue at risk as set out in the AER's Framework and approach paper.

SP AusNet proposed that no cap be applied to the reliability component of the STPIS for the forthcoming regulatory control period, pursuant to clause 2.2 of the STPIS, while maintaining the 0.5 per cent cap on each customer service parameter and the overall cap of 1 per cent on all customer service parameters. SP AusNet stated that its proposal to remove the cap on the reliability of supply parameters better aligns the scheme with the national electricity objective and the objectives at clauses 1.5(b)(5) and (6) of the STPIS. SP AusNet also stated that the cap discourages efficient investment in reliability of supply if that reliability level is beyond the limit imposed by the cap. Further, SP AusNet stated that the cap on the revenue 'upside':

> is simply penalising consumers by preventing them from receiving efficient reliability improvements as opposed to protecting them from paying windfall gains to a DNSP.[55]

SP AusNet also stated that:

> in SP AusNet’s case as the efficient level of reliability has been identified to lie beyond the limit imposed by the cap and the company believes its risk is adequately controlled with the other risk control measures in the STPIS.[56]

SP AusNet also noted that the cap has not been set against any efficient reliability benchmark, and that the justification for the cap is purely as a risk mitigation tool. However, SP AusNet submitted that the downside revenue risk that it faces is comprehensively addressed elsewhere in the STPIS, namely through the following risk mitigation tools:

- the exemption regime
- the S Bank
- variations proposed in the revenue proposal

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52 AER, *Framework and approach paper*, May 2009, p. 93.
53 CitiPower, *Regulatory proposal* p. 261.
54 Powercor, *Regulatory proposal* p. 266.
55 SP AusNet, *Regulatory proposal* p. 55.
56 ibid., p. 56.

- the suspension of the scheme in extreme cases.[57]

SP AusNet therefore proposed that no revenue cap be applied to the reliability parameters of the STPIS. Specifically, this involves not applying clause 2.5(a) and equation 4A in appendix C of the STPIS.[58]

United Energy submitted that a cap of 5 per cent of revenue at risk on the STPIS parameters is too high and would expose United Energy to the risk of wide revenue fluctuations. United Energy therefore proposed that a lower cap on revenue at risk of 3 per cent is appropriate.[59]

In support of its proposal for a 3 per cent cap on revenue at risk, United Energy stated that the 5 per cent cap included in the STPIS implies considerable asymmetry in the application of the STPIS nationally, noting the different caps applied by the AER to different DNSPs across the NEM. United Energy also considered that there is limited scope for it to improve reliability across its network on a sustained basis, stating:

> a major expenditure programme would need to be undertaken to cause enduring improvement to reliability, and this programme would necessarily entail the underground placement of key parts of the network.[60]

Further, United Energy stated that reliability is 'strongly influenced by seasonal and cyclical factors which cannot readily be controlled by the business'.[61]

United Energy also stated that under a 5 per cent cap on revenue at risk it would be exposed to the risk of wide fluctuations in its revenue, which in turn would result in unpredictable costs to consumers.[62] United Energy also modelled and back cast the outcomes that it would have received under the AER's STPIS since 2000. It concluded that the outcomes under the STPIS are more volatile than those under the ESCV scheme which is currently in place under the 2006–10 Electricity Distribution Price Review (EDPR). Therefore, United Energy stated that a 3 per cent cap would 'help dampen the significant oscillations in the bonus and penalty payments'.[63]
United Energy contended that:

- a 3 per cent cap would better balance the objectives of the STPIS
- and the lower cap would also play a valuable role in serving to ensure that the financial viability of the electricity distribution industry in Victoria is not undermined.[64]

Submissions on DNSP regulatory proposals

TRUenergy stated that it supports the revised S factor scheme to be applied by the AER in the forthcoming regulatory control period. In particular, TRUenergy noted

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57 ibid., p. 55.
58 SP AusNet, *Regulatory proposal* p. 56.
59 United Energy, *Regulatory proposal* p. 210–211.
60 United Energy, *Regulatory proposal*, Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme p. 28. app.)
61 ibid.
62 ibid., p. 29.
63 ibid.
64 ibid., p. 30.

that the total S factor revenue that a DNSP is able to achieve is capped at 5 per cent of its total regulated revenue, whereas the ESCV's uncapped scheme could result in large network tariff fluctuations.[65]

TEC stated that as it considered DNSPs' management is committed to short term rewards, business incentives act as a disincentive to achieving long term service performance of the network which is compounded in practice by the rewards for service performance being limited by the regulatory guidelines to 1 per cent of allowed revenue, although the NER allows this constraint to be as high as 5 per cent.[66]

TEC also stated that it considered that the 1 per cent constraint against revenue must be increased to overcome the business' financial performance incentive. It notes this would provide for much higher reward for reducing capex and opex. One way to achieve this is for a DNSP to pay a consumer for non-supply the same amount the consumer would pay if the supply was provided.[67]

AER considerations

The AER considers that the proposal by CitiPower and Powercor to apply the STPIS default cap on revenue at risk of 5 per cent for the forthcoming regulatory control period is consistent with the objectives of the STPIS. The AER will apply the scheme default of 5 per cent revenue at risk to CitiPower and Powercor. As Jemena did not make specific proposals regarding revenue at risk, the AER will apply the scheme default of 5 per cent revenue at risk to Jemena.

After seeking clarification from the TEC regarding its submission, the AER understands that the TEC was referring to the 1 per cent cap on the customer service component of the STPIS. Section 2.5 of the STPIS states that 'the sum of the S factors associated with all parameters must lie between +5 per cent (the upper limit) and –5 per cent (the lower limit)'. The AER notes that the NER do not place any restriction on the amount of revenue that can be at risk under the STPIS.

SP AusNet

In regards to SP AusNet's proposal to remove the cap on the level of revenue at risk, the AER accepts SP AusNet's argument that a cap limits the incentives for DNSPs to provide service improvements. However, the AER considers that the cap on revenue at risk mitigates some of the risks associated with the STPIS and, as such, is an important aspect of the scheme's design.

The AER accepts that retaining a cap may impact a DNSP's investment strategy and encourage a more measured reliability improvement program. However, the AER recognises that a cap on the revenue at risk has the benefit of protecting end users against large swings in tariffs that are possible under an uncapped scheme. Whilst the cap on revenue at risk limits the incentives to improve supply reliability, the AER notes that a DNSP which has reached its revenue cap on the upside still has a financial incentive to prevent its reliability from worsening in subsequent years. As such,

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65 TRUenergy, *Submissions on SP AusNet, Powercor and United Energy regulatory proposals*, 16 April 2010, p. 3.

66 TEC, *Submission to the AER,* Attachment A, 11 February 2010, p. 35, 36.

67 ibid.

customers may continue to derive a benefit from the scheme even if a DNSP has achieved enduring improvements in supply reliability to reach its upside revenue cap.

The AER notes that, with no cap on revenue at risk, there is no practical limit on the change in tariffs or a DNSP's revenue from year to year. Further, SP AusNet proposed to increase its MED threshold, which also increases the potential size of swings in the DNSP's revenue and customer tariffs from year to year (this issue is discussed at section 15.7.5). The AER considers that customers are unlikely to accept large changes in tariffs due to variations in a DNSP's performance, which may vary annually as a result of events outside the DNSP's control. A cap on revenue at risk limits the size of changes in tariffs and a DNSP's revenue. For example, with the default cap on revenue at risk, SP AusNet's revenue and customer tariffs could change by up to 10 per cent between two regulatory years. The AER notes that the s-bank mechanism can be used to reduce the size of annual variations in revenue. However, it may not be able to mitigate the risks associated with an uncapped scheme.

The AER acknowledges that, in support of its proposal for uncapped revenue at risk, SP AusNet has provided a list of risk mitigation tools, including the MED threshold, s-bank and the ability to suspend the scheme. The AER recognises that the MED threshold and s-bank mechanism do provide a degree of risk mitigation. However the AER considers that relying on the possibility of suspending the scheme results in an asymmetric risk profile whereby the DNSP has a large upside benefit but, in the event that the scheme is suspended, it is not exposed to the full downside risk of an uncapped scheme. The AER considers that suspending the scheme should only be considered in extreme circumstances and should not be relied upon as a risk mitigation strategy. The AER notes that the cap on revenue at risk is symmetric and as such, the need to suspend the scheme would be made more likely by removing the cap on revenue at risk, as this would allow for large decreases in SP AusNet's revenue.

For these reasons and having regard to the objectives of the STPIS, the AER does not consider an uncapped scheme to be appropriate as an uncapped scheme places unnecessary risk on the future tariffs of customers and the revenues of a DNSP, relative to the benefits which consumers may derive from removing the cap.

SP AusNet indicated in its regulatory proposal that the efficient level of reliability for its network lies outside the reliability improvements covered by the cap, however, it did not support this statement with any evidence.

The AER has considered the specific circumstances of SP AusNet and reviewed its historical reliability performance in comparison to the other Victorian DNSPs, in particular Powercor, which has a network with a broadly similar mix of urban and rural characteristics to SP AusNet. Figure 15.1 shows that SP AusNet's SAIDI performance[68] has historically been significantly below the average of the other Victorian DNSPs, including Powercor. The AER's analysis indicates that, if SP AusNet were to improve its reliability to the average performance of the other Victorian DNSPs, the 5 per cent cap on revenue at risk will be exceeded. That is, the

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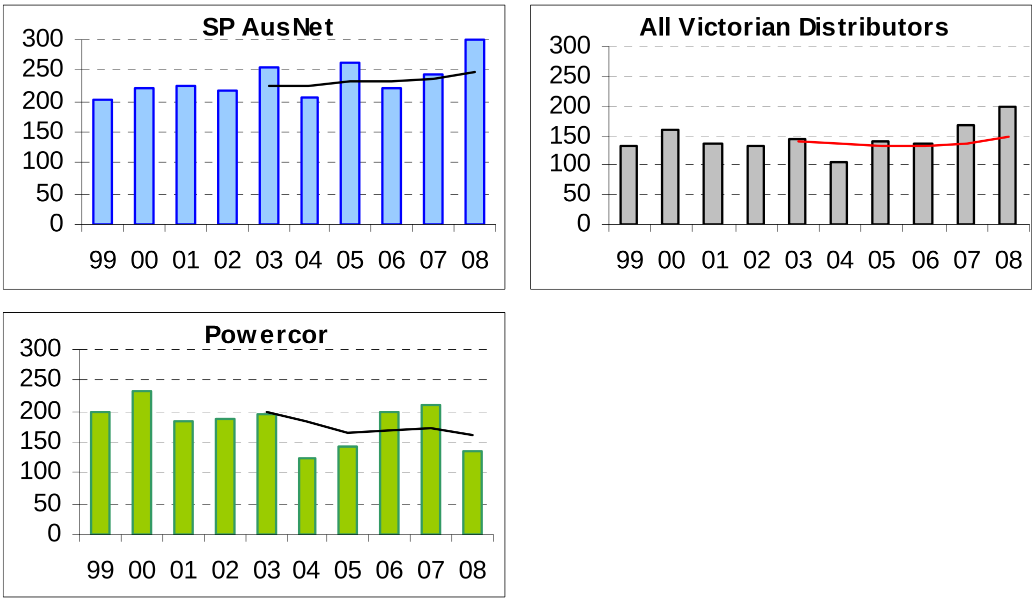
68 Preliminary analysis of the 2009 performance data provided by SP AusNet in its annual performance reporting indicates that SP AusNet under performed against its target in 2009. The AER notes that SP AusNet's 2009 performance was impacted by the 7 February bushfire.

cap on revenue at risk may restrict the incentive on SP AusNet, over the forthcoming regulatory period, to achieve service reliability comparable with the other Victorian DNSPs. As such, the AER considers that it is appropriate for SP AusNet to have an incentive to increase its reliability by a larger amount to bring its performance closer to the other Victorian DNSPs.

Figure 15.1 SP AusNet; Powercor; and all Victorian DNSPs—historical SAIDI performance (minutes)



Source: AER, *Victorian Electricity Distribution Businesses, Comparative Performance Report 2008*, November 2009, p. 30.

While recognising that increases to the revenue at risk above the default 5 per cent will provide an incentive for SP AusNet to improve supply reliability by a greater amount, the AER has also considered the level of risk for SP AusNet and its customers from higher revenue and tariff volatility. Having regard to both these factors, the AER considers that, instead of an uncapped scheme with a large price risk to customers, a smaller increase in the revenue at risk represents an appropriate balance. The AER is also aware that its STPIS replaces the S factor scheme previously administered by the ESCV and the experience for both customers and DNSPs under this STPIS is untested at this time, as such the AER considers it prudent to only allow a measured increase in the cap on revenue at risk.

For these reasons, the AER considers that a 7 per cent cap on revenue at risk is an appropriate and measured increase in SP AusNet’s revenue at risk. This is a symmetric increase in the cap on revenue at risk so SP AusNet will be subject to both greater upside and downside revenue at risk. This proportion balances the financial incentive to improve performance and the risk to SP AusNet and customers of large tariff fluctuations and the willingness of end users to pay for service improvements.

Increasing the cap on revenue at risk to 7 per cent, puts at risk an additional 2 per cent of SP AusNet's revenue per annum—approximately $7.6 million ($, nominal) in 2011 increasing to $9.5 million ($, nominal) in 2015 (based on this draft decision). This represents approximately an extra 0.7 per cent possible change in customers’ electricity bills—assuming distribution services currently amount to 35 per cent of electricity bills for SP AusNet's residential customers. However, it is important to note that this extra 2 per cent revenue at risk will only become a factor if SP AusNet's reliability of supply improves or deteriorates by more than the 5 per cent cap.

Increasing the cap on revenue at risk allows for customers to receive a greater reduction in fees if SP AusNet's performance decreases by a relatively large amount, conversely customers may be exposed to greater increases in fees if SP AusNet's performance increases by a relatively large amount.

United Energy

The AER does not accept United Energy's proposal for a 3 per cent cap on revenue at risk. The AER recognises United Energy's argument that a 3 per cent cap may reduce the volatility in a DNSP's revenue and therefore in customer tariffs. However, a 3 per cent cap on revenue at risk reduces the size of the incentive on the DNSP to improve reliability. The AER considers that the size of the incentive and the volatility of the scheme are appropriately balanced with a 5 per cent cap on revenue at risk.

In support of its argument United Energy has applied the AER's STPIS to its historical performance data to illustrate that the scheme is more volatile than the ESCV's S factor scheme. The AER has analysed the information provided by United Energy and, not withstanding the discrepancies between the figures United Energy has provided to the AER on this issue (namely, figure 16-1 on page 212,[69] figure 1-2 on page 29 of the appendix[70] and the model provided to the AER on 22 March 2010[71]), the AER is not satisfied that United Energy has demonstrated that the AER's STPIS will lead to an unacceptable level of volatility in revenues with a 5 per cent cap on revenue at risk.

The AER has analysed the information provided by United Energy to the AER in support of its proposed 3 per cent cap of revenue at risk and presented its analysis along side United Energy's proposal at figure 15.2. The AER's analysis shows that United Energy appears to have applied a banking strategy which exacerbates the volatility of revenue resulting from the STPIS. United Energy's model assumes that it would have a negative S factor of 5 per cent in 2011 and 2012. United Energy's model banks the entire S factor in 2011, however, in 2012 when it also has an S factor of negative 5 per cent, it does not bank any of the S factor. This results in a total change in revenue in 2012 of negative 7.1 per cent and a total change in revenue in 2013 of 9.4 per cent. Whilst this is a potential outcome under the STPIS, United Energy did not provide any justification as to why it adopted this approach in its modelling.

The AER's analysis on the other hand, employs a consistent approach to the application of the s-bank. For the purposes of comparison, the AER's analysis at figure 15.2 banks the entire s factor penalty or reward in the year it is incurred. This alternative banking strategy, as seen in the line 'AER—Consistent banking', in figure 15.2, results in a much smaller negative 2 per cent total change in revenue in 2012 and a zero change in revenue in 2013. The AER considers this to be a more

69 United Energy, *Regulatory proposal* p. 212.

70 United Energy, *Regulatory proposal*, Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme p. 29. app.)

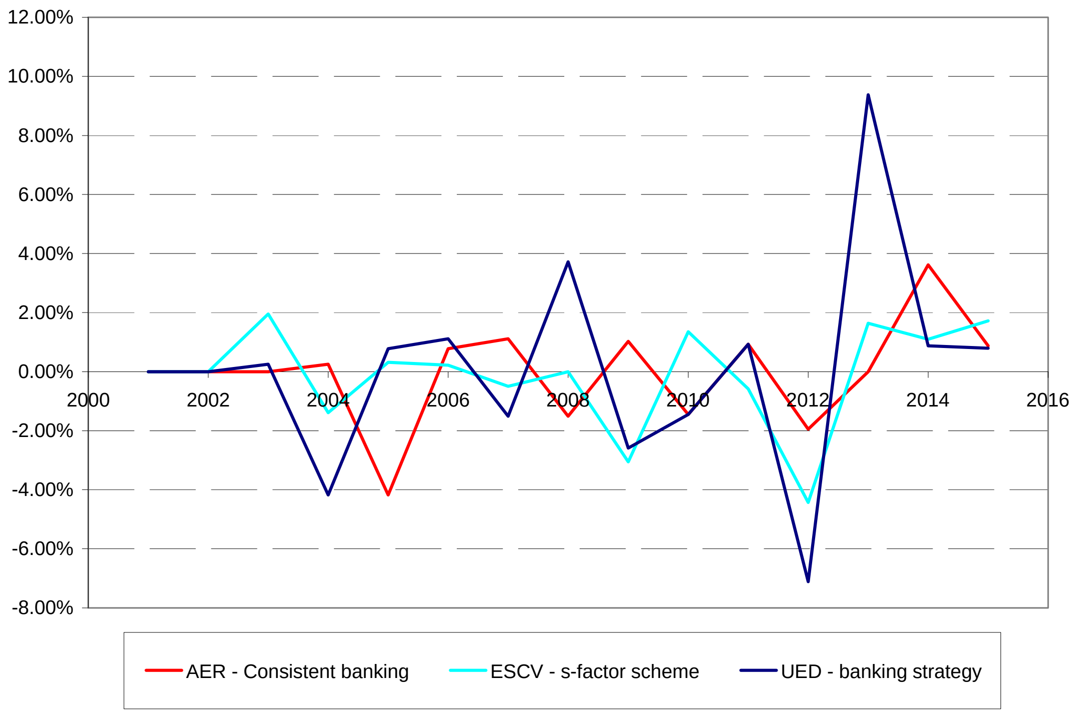
71 United Energy, email to AER 22 March 2010.

likely outcome of the application of the s-bank and is more reflective of the underlying volatility that United Energy may face under the AER's STPIS.

The AER notes that under United Energy's banking strategy, the total change in revenue would have exceeded 5 per cent only once on the upside and once on the downside in the years 2001 to 2015. The AER also notes that the total change in revenue would have exceeded 3 per cent in four years during the same period—twice on the upside and twice on the downside. However, using the AER's more consistent banking approach, the total change in revenue would not have exceeded 5 per cent during this period and the total change in revenue would have exceeded 3 per cent three times—twice on the upside and once on the down side. Finally, the AER notes that by applying some discretion in its banking strategy United Energy could further reduce the volatility of the STPIS.

The AER notes that in the period from 2001–15 United Energy would have reached a cap on revenue at risk of 5 per cent twice and a cap on revenue at risk of 3 per cent seven times and the impact on United Energy and customers can be mitigate through the use of the s-bank. As such, the AER does not consider that this is an unacceptable level of volatility and considers that applying a 3 per cent cap on revenue at risk, which might be reached approximately half the time, would result in a material lessening of the incentives of the scheme.

Figure 15.2 United Energy—Revenue volatility under the AER STPIS



Source: United Energy, AER analysis.

The AER also notes that, in support of its proposed 3 per cent cap on revenue, United Energy stated that the AER applied a 3 per cent cap in its ETSA Utilities draft distribution determination 2010–11 to 2014–15. The AER's decision to apply a 3 per cent cap was due to the uncertainty regarding the appropriate MED threshold and an alternative statistical transformation which was applied to the SAIDI data. The AER stated that:

> 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.[72]

In this specific instance, the AER determined that a lower cap on revenue at risk was appropriate, due to concerns about the robustness of the data and use of that data as an input into the STPIS values. This decision does not set out a general precedent for other DNSPs to lower their cap on revenue at risk below 5 per cent. As required under the NER, the AER will make a decision as to the appropriate application of the STPIS in each distribution determination.

The AER considers that in this instance, a 3 per cent cap is not appropriate as it results in a reduction to the incentive that the scheme provides a DNSP to maintain and improve network reliability. The AER is satisfied that a 5 per cent cap on revenue at risk represents an appropriate balance between providing incentives for reliability improvements and the risks on DNSPs and customers.

Differences between STPIS and ESCV S factor scheme

The AER notes that the VCR has been substantially increased from $60 000 and $30 000[73] per MWh for CBD and all other customers respectively under the previous ESCV S factor scheme, to $95 700 per MWh for CBD customers, and to $47 850[74] per MWh for all other customers.[75] This increase will result in a larger reward or penalty for a 1 unit change in performance than under the ESCV S factor scheme (all other things being equal). Further, as the manner in which the two schemes operate differs, the AER considers that direct comparisons of the size of the benefits and penalties under the respective schemes is of limited value. The AER has therefore not undertaken a detailed comparative analysis on this issue.

AER conclusion

The AER proposes to increase the level of revenue at risk to ±7 per cent for SP AusNet. The level of revenue at risk remains unchanged at ± 5 per cent for CitiPower, Powercor, Jemena and United Energy. The cap on revenue at risk to apply as set out in table 15.10. For a discussion on the cap on revenue at risk for the customer service parameter see section 15.7.7.

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72 AER, *AER, South Australian distribution determination 2010–11 to 2014–15, Final decision, May 2010*, p. 360.

73 ESCV, 2006, *Electricity Distribution Price Determination 2006-2010 Volume 1*, p. 4.

74 CRA International, 12 August 2008, Assessment of the Value of Customer Reliability

75 VCR is expressed in 2008 terms and is indexed by CPI when calculating the incentive rate.

Table 15.10 Cap on revenue at risk (per cent)

	Proposed cap on revenue at risk	AER conclusion on cap on revenue at risk
CitiPower	±5	±5
Powercor	±5	±5
Jemena	±5	±5
SP AusNet	uncapped	±7
United Energy	±3	±5

Source: AER analysis.

15.7.4 Incentive rates

Framework and approach

The Framework and approach paper stated that:

- The Victorian DNSPs, in their regulatory proposals, will be required to propose incentive rates in accordance with the methodology set out in the STPIS, but may elect to propose an alternative VCR to that stated in the STPIS. Should the Victorian DNSPs elect to do this, they must provide the AER with the methodology used to calculate the value and research supporting their calculation.

- Incentive rates will be calculated at the commencement of the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.[76]

Victorian DNSP regulatory proposals

All Victorian DSNPs proposed to calculate the incentive rates in accordance with sections 3.2 and 5.3.2 of the STPIS. However, Powercor's proposal to segment its network by urban and rural network type would have had an effect on the incentive rates for its network.

Submissions on DNSP regulatory proposals

The Minister submitted that the AER should review the incentive rates of the STPIS based on the latest VCR.[77]

Both the Minister[78] and the CUAC[79] considered that incentives must ensure the benefits from services received outweigh or be commensurate to the costs incurred.

The EUCV considered services should improve with increased payments.[80]

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76 AER, *Framework and approach paper*, May 2009, p. 96.
77 Minister for Energy and Resources, *Submission to the AER*, p. 7, 8
78 ibid., p. 3.
79 CUAC, *Submission to the AER,*, p. 5.
80 EUCV, *Submission to the AER* , p. 65.

AER considerations

The AER's draft decision is to reject Powercor's proposal to segment its network by urban and rural network type as discussed in section 15.7.2. The incentive rates for all Victorian DNSPs will be calculated using the STPIS feeder categories.

It should be noted that, as stated in the previous section, the VCR rates have been increased compared with the ESCV S factor scheme.[81] The VCR rates, which are indexed by CPI, represent the latest available information at the time of this draft decision.[82] The AER considers that these rates are appropriate and should ensure that the benefits customers receive from the STPIS are commensurate with any increased costs that are imposed upon them.

AER conclusion

The AER considers it appropriate to apply the incentive rate calculation as set out in appendix A of the STPIS. As discussed in chapter 5, the AER has requested that the Victorian DNSPs resubmit an estimate of their forecast average annual energy consumption. As both this and the DNSPs' annual smoothed revenue requirement are inputs into the calculation of the incentive rates, the AER will update the incentive rates for any relevant changes between the AER's draft and final determinations. The incentive rates in table 15.11 are contingent on these updates.

[81] ESCV EDPR, 2006–10 Volume 1, p. 4.
[82] CRA International, 12 August 2008, Assessment of the Value of Customer Reliability

Table 15.11 AER conclusion—Incentive rates (per cent per unit)

	CitiPower	Jemena	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI	0.1731	–	–	–	–
SAIFI	9.2794	–	–	–	–
MAIFI	0.7424	–	–	–	–
Urban	–	–	–	–	–
SAIDI	0.0660	0.1299	0.0577	0.0444	0.1432
SAIFI	3.2702	7.8702	3.7592	3.0734	8.7494
MAIFI	0.2616	0.6296	0.3007	0.2459	0.6999
Short Rural	–	–	–	–	–
SAIDI	–	0.0054	0.0323	0.0350	0.0152
SAIFI	–	0.3497	2.5761	3.0267	0.9385
MAIFI	–	0.0280	0.2061	0.2421	0.0751
Long Rural	–	–	–	–	–
SAIDI	–	–	0.0280	0.0157	–
SAIFI	–	–	2.8058	1.3457	–
MAIFI	–	–	0.2245	0.1077	–

Source: AER analysis.

The AER notes that these incentive rates will need to be updated to account for any relevant changes between the AER's draft and final decision.

15.7.5 Major event day threshold

This section sets out the following four issues raised in the Victorian DNSPs' regulatory proposals regarding the setting of the MED threshold:

- increasing the MED threshold to greater than 2.5 beta from the mean for SP AusNet and Powercor
- calculating separate MED thresholds for urban and rural sections of the network for United Energy
- holding the MED threshold constant over the forthcoming regulatory control period for United Energy and Jemena
- differences in the interpretation of the calculation of the MED threshold by United Energy and Jemena.

Increase in the MED threshold

Framework and approach

The AER's Framework and approach paper did not address changes in the MED threshold as such changes were not allowed under the STPIS, at the time the Framework and approach paper was released. However, in November 2009, subsequent to the release of the Framework and approach paper the AER amended the STPIS to permit a DNSP to propose a higher beta value.[83] The amended STPIS is in force for the purposes of the 2011–15 Victorian distribution determinations.

The amended STPIS provides greater flexibility with respect to the exclusion threshold that can be applied under the scheme. The AER considered greater flexibility was required as there could be circumstances where a DNSP may consider that the use of 2.5 beta (the IEEE standard) from the mean in setting the MED threshold inappropriate and may wish to apply a greater MED threshold.[84] The amended STPIS therefore allowed a DNSP to propose a higher MED threshold in its regulatory proposal in order to:

a. better reflect the service performance characteristics of its network

b. provide sufficient incentive for a DNSP to maintain or improve service performance.

The AER considered that this flexibility could in certain circumstances result in more efficient outcomes as compared to the application of the 2.5 beta threshold.

The AER proposed that a DNSP be required to use a 2.5 beta as the MED threshold while allowing a greater MED threshold to be used where appropriate. A DNSP seeking to apply a greater beta threshold would be required to:

a. demonstrate to the AER that its approach was consistent with the objectives of the scheme

b. provide supporting information, as required by clause 2.2 of the scheme.[85]

Victorian DNSP regulatory proposals

CitiPower, Jemena and United Energy have proposed to implement the default MED threshold of 2.5 beta from the mean as set out in the STPIS. SP AusNet and Powercor have proposed MED thresholds greater than 2.5 beta from the mean.[86]

SP AusNet submitted that if a 2.5 beta MED threshold was applied to it then the threshold would exclude many days containing events that are not extreme or unusual. SP AusNet contended that performance on these days would in fact be within its ability to control or improve.[87] SP AusNet proposed a MED threshold of 3.2 beta on the basis that it would appropriately exclude only extreme events.[88] SP AusNet

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83 Final decision, *Electricity distribution network service providers service target performance incentive scheme*, November 2009

84 ibid., p. 10.

85 ibid., p. 10.

86 SP AusNet, *Regulatory proposal* p. 57. Powercor, *Regulatory proposal* p. 268.

87 SP AusNet, *Regulatory proposal* p. 57.

88 ibid.

considered that a 3.2 beta MED threshold would better align the scheme with the national electricity objective.[89]

Powercor proposed a MED threshold of 3.1 beta to ensure that expenditure efficiencies are not pursued at the expense of day-to-day system reliability. Powercor also stated that a MED threshold of 3.1 beta would provide it with a stronger incentive to improve performance.[90]

Submissions on DNSP regulatory proposals

The Minister requested the AER review the risk that:

- if targets for 2011 are not the actual performance in 2010, Victorian customers may effectively pay for improvements in reliability that they have already effectively paid for or that electricity distributors are penalised for a deterioration in reliability that they have already been penalised for.

The AER acknowledges the Minister's concern regarding the importance of setting an appropriate target for each DNSP. Under the STPIS, DNSPs’ performance targets are based on their historical averages of the previous five years. Hence, customers will only pay for real improvements, if a DNSP outperformance such targets. As discussed in section 15.7.1, the AER considers the appropriate historical data to use in setting the performance targets is the audited 2005–09 performance data.

Further, as the STPIS shall apply to the Victorian DNSPs from 2011, Victorian DNSPs’ historical performance under the ESCV's S factor scheme will be closed out appropriately. Details of this closing out process are in section 15.7.12.

AER considerations

The AER has analysed the effect of altering the MED threshold on the SAIDI and SAIFI targets and the actual performance of DNSPs against these targets. A DNSP's SAIDI target performance is based on the average of its average historical performance adjusted for exclusions permitted under the STPIS including the relevant MED threshold. As such, the application of a higher MED threshold results in a higher SAIDI target for the DNSP. The application of a higher MED threshold also includes a greater number of large outage events in the measurement of reliability performance which ensures that DNSPs have the incentive to mitigate the effects of these relatively large outage events.

The AER has identified the following two concerns with increasing the MED:

1. the SAIDI and SAIFI targets are influenced by a small number of data points at higher MED thresholds
2. the increased volatility in the measurement of DNSPs' reliability performance at higher MED thresholds.

89 ibid.
90 Powercor, *Regulatory proposal* p. 268.

SAIDI targets are influenced by a small number of data points

The AER analysed the effect on the DNSPs' SAIDI and SAIFI targets of changing the number of standard deviations (beta) from the mean at which the MED threshold is set. The results indicated that, once the beta parameter gets sufficiently high, the small number of large outage events—which occurred in the past five years that are either included or excluded in the calculation of the target depending on the beta value chosen—have a disproportionate effect on the target. At higher MED thresholds, the accuracy of the performance targets is negatively impacted by the limited number of data points for major outage events.

The transition from the ESCV's S factor scheme means that past performance has been measured, and rewarded or penalised on a different basis to that on which the targets for the STPIS are set. The starting position of the target for the STPIS determines the total amount of additional revenue a DNSP may earn in transitioning to its equilibrium level of reliability. As such, DNSPs may be over or under compensated if the initial target is set inaccurately.

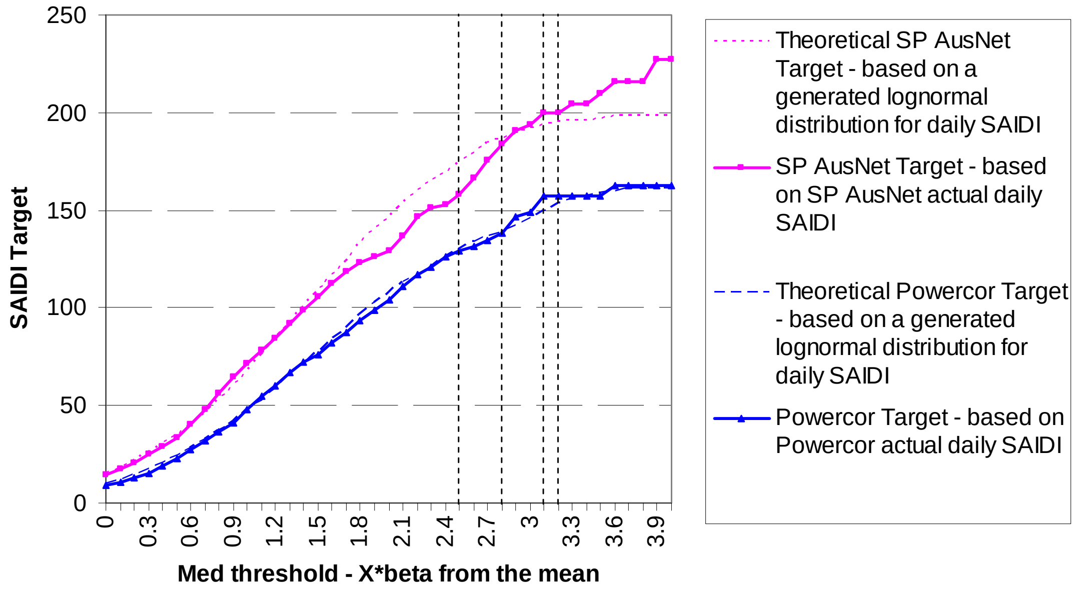
Figure 15.3 shows the SAIDI targets for SP AusNet and Powercor, as well as a theoretical target based on a log-normal distribution generated using the average and standard deviation of SP AusNet's and Powercor's respective daily SAIDI data.[91] The AER recognises that the theoretical target is not necessarily representative of the underlying statistical distribution of SP AusNet's and Powercor's network. However, it demonstrates that with enough data points, a smooth relationship should hold between the SAIDI target and the MED threshold. Whilst at all MED thresholds there is a probability that the target calculated on historical data is either higher or lower than the underlying reliability of the network, the potential size of such differences increases as the MED threshold increases. This is particularly problematic once the target starts increasing in discrete steps.

As seen in figure 15.3, at high MED thresholds, the calculated SAIDI target stays constant between some MED thresholds and increases in large discrete steps at others, instead of the expected smooth increasing target resulting from the higher MED threshold. The step nature of changes in the SAIDI target indicates that there are no longer sufficient data points to accurately set the SAIDI targets at these higher MED thresholds. The AER's analysis of both SP AusNet's and Powercor's historical performance data indicates that, with a MED threshold greater than 2.8 beta from the mean, there is a risk that the benefit which consumers receive from the scheme would no longer correspond with the DNSPs' rewards or penalties under the scheme. This is because the AER can no longer be confident that the performance data calculated from the limited data points accurately represents the underlying reliability of the DNSPs' network.

The AER also notes that Powercor appears to have chosen a MED threshold such that further increases in the beta parameter will have no impact on the SAIDI target and small decreases in the beta parameter will result in relatively large reductions in the SAIDI targets. This approach could potentially result in easier targets than would otherwise be the case.

91 This theoretical target was based on 10,000 generated log-normally distributed random variables, representing 27.5 years of daily SAIDI data.

Figure 15.3 SP AusNet and Powercor—Relationship between SAIDI target and the MED threshold



Source: AER analysis.

The AER considers that the performance targets must be set with a reasonable degree of accuracy to ensure the benefits or penalties incurred by DNSPs are commensurate with the benefits received by the customers.

Increased volatility

The AER considers that increasing the MED threshold increases the incentives on DNSPs to improve reliability of supply because it increases the potential size of the rewards and penalties offered under the STPIS. However, increasing the MED threshold also increases the volatility of the DNSPs' revenue and customer tariffs. The AER is concerned that not all customers are willing to accept large variations in tariffs.

Figure 15.4 and figure 15.5 illustrate the differences between the SAIDI performance of SP AusNet and Powercor over the past five years at different MED thresholds, compared against what their respective targets would be—at the respective MED threshold—for the forthcoming regulatory control period.[92]

The AER notes that figure 15.4 and figure 15.5 are based on historical data, and the actual outcomes over the forthcoming regulatory control period will vary. However, the historical data indicates that moving from a MED threshold 2.5 beta from the mean to a MED threshold 3.2 or 3.1 beta from the mean, as proposed by SP AusNet and Powercor respectively, could double the size of both the rewards and penalties paid under the STPIS.

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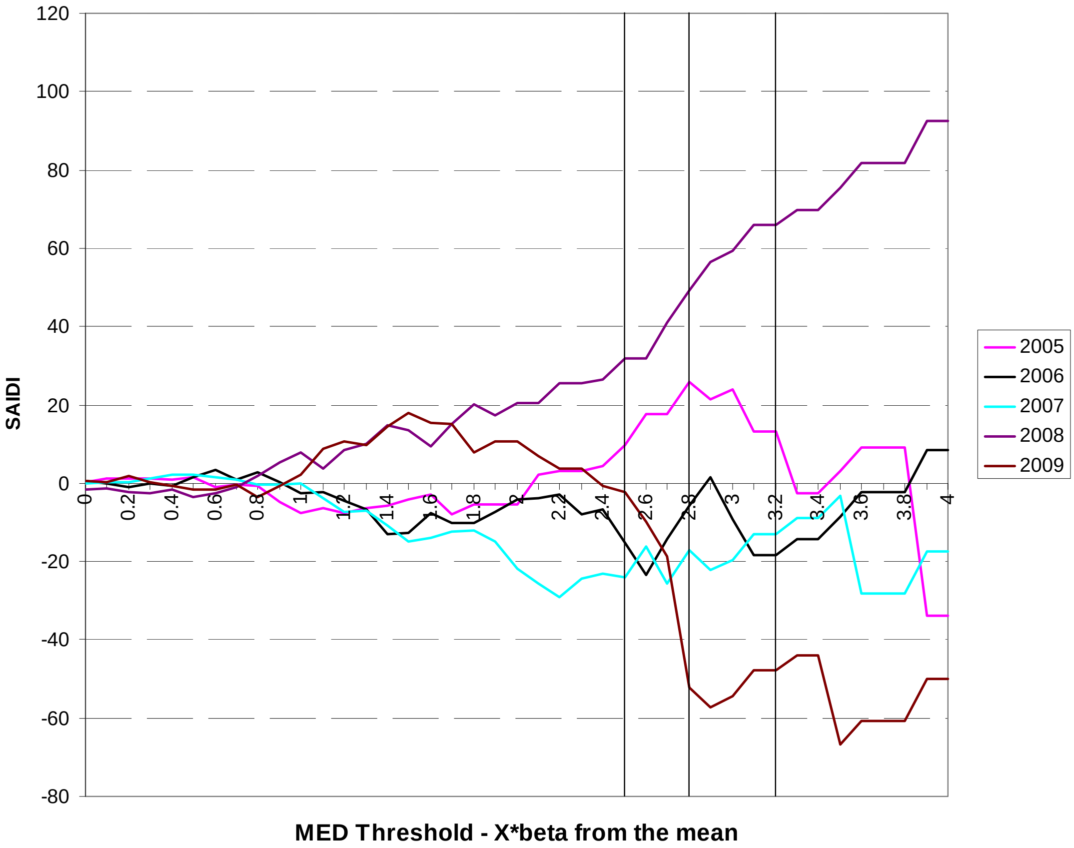
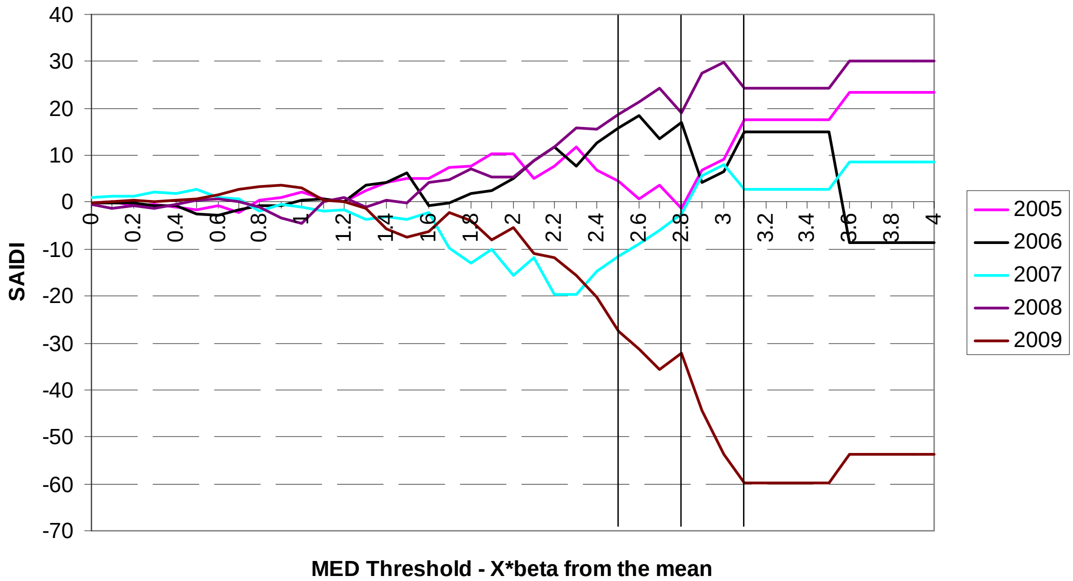
92 Figure 15.4 and 15.5 compare SP AusNet's and Powercor's performance in each of the past five years against their average performance over the past five years.

Figure 15.4 SP AusNet—Difference between actual and average (target) performance



Source: AER analysis.

Figure 15.5 Powercor—Difference between actual and average (target) performance



Source: AER analysis.

Table 15.12 SP AusNet and Powercor—Range of SAIDI performance against the target (2005–09)

MED Threshold	2.5 beta from the mean	2.8 beta from the mean	3.1 beta from the mean	3.2 beta from the mean
SP AusNet				
Maximum outperformance	31.1	50.7	67.2	71.2
Maximum underperformance	–20.3	–50.2	–45.8	–41.8
Range	51.4	100.9	113.0	113.0
Powercor				
Maximum outperformance	20.4	20.7	27.9	27.9
Maximum underperformance	–34.0	–38.5	–74.0	–74.0
Range	54.4	59.3	102.0	102.0

Source: AER analysis.

Table 15.12 summarises the information presented in figure 15.4 and figure 15.5 and, shows the maximum differences between performance and the target for SP AusNet and Powercor. It indicates that, based on five years of observed historical data, the range of SP AusNet's and Powercor's performance against their targets approximately doubles as the MED threshold increases from 2.5 beta from the mean to 3.2 and 3.1 beta from the mean respectively. That is, increasing the beta to the amounts proposed by the DNSPs, might reasonably be expected to double the size of the rewards and penalties paid under the performance component of the STPIS. Similar results are observed for SP AusNet's and Powercor's performance against their SAIFI targets.

SP AusNet's and Powercor's historical results differ in that SP AusNet has a large increase in the rewards and penalties when moving from 2.5 to 2.8 beta from the mean, while Powercor's change is relatively small over this range. It is difficult to ascertain whether this is due to differences in the underlying nature of the networks or more simply the result of the random nature of large SAIDI events. Regardless, the relationship is clear—increasing the MED threshold increases the size of the rewards and penalties paid under the STPIS.

The AER considers that the probability of large variations in the S factor are made more likely as the MED threshold increases. The AER accepts that the cap on revenue at risk effectively places an upper limit on the volatility of DNSPs' revenue and that the s-bank mechanism can also be used to smooth the changes in customer tariffs. Hence, the AER is willing to accept some additional revenue volatility and tariff fluctuations in order to provide stronger incentives to DNSPs to achieve improved supply reliability.

AER conclusion

The AER considers that increasing Powercor’s and SP AusNet’s MED threshold from the default of 2.5 to 2.8 beta from the mean is appropriate. The AER considers that setting the MED threshold at 2.8 beta from the mean increases the incentives on the

DNSPs to improve supply reliability and does not unreasonably increase the volatility of the scheme. Further, at this MED threshold the AER is satisfied that the performance targets are not unduly influenced by a few very large unusual events. The AER considers that using a MED threshold as high as 3.2 or 3.1 beta from the mean in this instance is not in accordance with the objectives of the STPIS, and that consumers will not necessarily receive a commensurate benefit.

Additionally, the AER notes that its STPIS replaces the scheme previously administered by the ESCV and that the experience of both customers and the Victorian DNSPs under the new scheme is at this time untested. While the AER will agree to some increase in the MED threshold, the AER considers it prudent to only allow a measured change in the MED threshold at this time.

The AER considers a MED threshold 2.5 beta from the mean to be an appropriate MED threshold for CitiPower, Jemena and United Energy, which either proposed to apply the default of 2.5 beta from the mean, or did not propose a change from the STPIS.

The AER will calculate the MED thresholds using the beta values set out in table 15.13.

Table 15.13 AER conclusion—MED threshold set X beta from the mean

MED thresholds	Proposed beta values	AER conclusion—beta values
CitiPower	2.5	2.5
Powercor[a]	3.1	2.8
Jemena	2.5	2.5
SP AusNet[b]	3.2	2.8
United Energy	2.5	2.5

(a) The proposed MED threshold was 3.1 beta from the mean. The AER has set the MED threshold 2.8 beta from the mean.
(b) The proposed MED threshold was 3.2 beta from the mean. The AER has set the MED threshold 2.8 beta from the mean.
Source: AER analysis.

Separate MED thresholds for the urban and rural sections of the network

Victorian DNSP regulatory proposals

United Energy proposed to calculate separate MED thresholds for the urban and rural sections of its network. United Energy contended that as performance targets and VCR are separately calculated for the urban and rural sections of the network, MED thresholds should also be separately calculated.[93]

[93] United Energy, *Regulatory proposal*, Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme p. 7. app.).

AER considerations

The AER notes that separately calculating the MED threshold for different sections of the network would result in the threshold for excluding the entire network's reliability being dependent on the threshold in individual segments of the network. As such, an event which impacted only on one section of the network could provide a trigger for excluding the entire network. This would occur even if the performance of the network as a whole would not have exceeded the MED threshold. The AER does not consider that United Energy has sufficiently demonstrated that the proposed change is in accordance with the objectives of the scheme.

The AER considers that the MED threshold is a statistical basis to measure the impact of events with respect to a DNSP's overall capacity to manage its network and, as such, it is appropriate that the entire network is measured.

Further, the AER notes that calculating the MED threshold for the scheme as a whole is the methodology set out in the STPIS. This is an element of STPIS which has been widely consulted on previously. The AER considers that the calculation methodology set out in appendix D to the STPIS is appropriate to apply to the Victorian DNSPs over the 2011–15 regulatory control period.

Constant MED threshold over the forthcoming regulatory control period

Victorian DNSP regulatory proposals

United Energy and Jemena proposed to hold the MED threshold constant throughout the forthcoming regulatory control period and not recalculate it each year as prescribed by the STPIS. In support of this amendment, Jemena argued that the STPIS is internally inconsistent as the targets are fixed for the period, whereas the MED threshold is calculated annually, and will therefore vary depending on actual performance outcomes during the period. Jemena stated that:

> this presents an unacceptable and unwarranted risk...[94]

Further, Jemena stated that as the targets are fixed for the entire period:

> …an annual reassessment of the [major event day threshold] using a rolling five-year average has the potential to expose the DNSP to a changing [major event day threshold], with a resultant risk of not achieving the reliability targets. It creates risks that DNSPs cannot be expected to efficiently manage because major event days are, by their nature, uncontrollable. [95]

United Energy stated that it:

> does not believe that the major event day threshold should be updated annually for each year of the forthcoming regulatory period as detailed in appendix D of the STPIS. United Energy considers that the threshold should remain fixed over the forthcoming period because the performance targets will also remain unchanged. Empirical work undertaken by United Energy

[94] Jemena, *Regulatory proposal* p. 201.
[95] ibid.

> has shown that the calculated targets are sensitive to the value of the exclusion threshold that is applied.[96]

AER considerations

United Energy and Jemena proposed that the MED threshold should be held constant throughout the forthcoming regulatory control period, and not recalculated each year as prescribed by the STPIS. The AER notes this will result in a different MED threshold being applied each year to the DNSPs' performance data. This is an element of the scheme's design which was widely consulted on during its development.

The AER also notes in setting IEEE standard 1366–2003, the Institute of Electrical and Electronics Engineers (the IEEE) examined the appropriate amount of data to use in setting the MED threshold. The IEEE found that:

> From a statistical point of view, the more data used to calculate a threshold, the better. However, the random process producing the data changes over time as the distribution system is expanded and operating procedures are varied. Using too much historical data would suppress the effects of these changes.[97]

And that:

> The consensus of the Design Working Group members was that 5 years was the appropriate amount of data to collect. They felt that the distribution system would change enough to invalidate any extra accuracy from more than 5 years of data.[98]

The Design Working Group of the IEEE appears to have had concerns that the accuracy of the MED threshold is compromised by using outdated outage information. If the MED threshold is not updated annually, then in 2015 (the end of the forthcoming regulatory control period) the MED threshold will be based on data that is between 5 and 10 years old. As such, the AER considers that there is benefit to updating the MED threshold annually to ensure up to date outage information is included in its calculation.

Calculation of the MED threshold

Victorian DNSP regulatory proposals

CitiPower, Powercor and SP AusNet applied a consistent methodology in calculating the MED threshold, while Jemena and United Energy applied an alternative methodology as set out below.

United Energy explained its methodology for calculating the MED threshold as follows:

> - The daily SAIDI data was first purged of the effects of “upstream” events such as load shedding, and transmission line failures.

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96 United Energy, *Regulatory proposal* p. 216.
97 IEEE Std 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices, p. 33.
98 ibid, p. 33.

- The major event day boundary was then calculated using the modified database. The value of the MED threshold obtained was 4.75 minutes, based on the calculated values of alpha (-3.326) and beta (1.954).

- In the next stage, the exclusion threshold thus calculated was applied back to the database, and the days for which the recorded SAIDI was in excess of 4.75 minutes were expunged from the data. Manual filtering of the data revealed that there were eleven days with a reported unplanned SAIDI in excess of 4.75 minutes. These eleven observations were deleted from the dataset used in the final stage of the computations.

- The exclusion threshold was again calculated, and was found to be 4.02 minutes, with alpha equal to -3.363 and beta equal to 1.903. The exclusion threshold of 4.02 minutes was then applied to the calculation of performance targets for SAIDI, SAIFI and MAIFI. This meant that the targets were computed without reference to the eleven days that had already been removed.[99]

Jemena did not provide any commentary on its calculation of the MED, however, after reviewing its spreadsheets, the AER determined that it used the same methodology as United Energy.

AER considerations

The AER's assessment revealed some ambiguity in the calculation of the MED threshold pursuant to appendix D of the STPIS, in particular in relation to step 1 of appendix D, which states:

> Collect values of daily unplanned SAIDI over five sequential regulatory years ending on the last day of the last complete reporting period—these values should reflect any exclusions permitted under clause 3.3 and 5.4 of the scheme. If fewer than five regulatory years of historical data are available, the most recent data should be used.

Clauses 3.3 and 5.4 of the STPIS set out the exclusions that apply to the reliability parameters and customers service parameters respectively. Clause 3.3(b) states:

> An event may also be excluded where daily unplanned SAIDI for the DNSP’s distribution network exceeds the major event day boundary, as set out in appendix D, when the event has not been excluded under clause 3.3(a).

The AER considers that CitiPower, Powercor and SP AusNet have interpreted clause 3.3 as was intended under the STPIS. However, the AER does not consider this to be the case for Jemena and United Energy, which have applied a circular interpretation to clause 3.3. Their interpretation is circular as it involves first calculating an initial MED threshold as an input into the process to calculate the final MED threshold. Second, the data to which the MED threshold has been applied is then used as the basis for recalculating it again. This approach to the calculation resulted in a MED threshold lower than would be the case if the calculation was applied as intended.

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99 United Energy, *Regulatory proposal*, Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme) p. 7. app.

The AER considers that Jemena's and United Energy's interpretation of the calculation methodology for the MED threshold, which requires the calculation of the MED threshold twice, is counterintuitive. It also clearly undermines the incentives of setting a MED threshold in the first place and applying such an interpretation is also arguably inconsistent with the manner in which the AER must make the Victorian distribution determinations, as required under section 16 of the NEL.

For these reasons the AER has therefore removed the effect of applying the exclusions at clause 3.3(b) as an input into the calculation of the MED boundary threshold from Jemena's and United Energy's MED threshold calculation.

The AER considers that CitiPower's calculation of the MED threshold is appropriate and has left it unchanged from its regulatory proposal.

The AER has updated SP AusNet's and Powercor's MED thresholds to reflect the exclusion threshold of 2.8 beta from the mean.

The AER has calculated the following MED thresholds, for the first year of the forthcoming regulatory control period for, the Victorian DNSPs as set out in table 15.14. These MED thresholds have been calculated in accordance with section 3.3 of the STPIS. The MED threshold for subsequent years will be calculated in accordance with section 3.3 of the STPIS.

Table 15.14 AER conclusion on MED thresholds (SAIDI, minutes)

MED thresholds	Proposed	AER determined
CitiPower	1.28	1.28
Powercor[a]	14.99	9.50
Jemena	6.62	7.04
SP AusNet[b]	20.00	11.23
United Energy	4.02	4.75

(a) The proposed MED threshold was 3.1 beta from the mean. The AER has set the MED threshold 2.8 beta from the mean.
(b) The proposed MED threshold was 3.2 beta from the mean. The AER has set the MED threshold 2.8 beta from the mean.
Source: Spreadsheets provided by DNSPs with regulatory proposals and AER analysis.

15.7.6 Proposed exclusion for demand management

Victorian DNSP regulatory proposals

SP AusNet submitted that non-network solutions that are implemented should be excluded from the calculation of the S factor in order to remove any potential barriers to the uptake of demand management.[100]

[100] SP AusNet, *Regulatory proposal* p. 57.

Submissions on DNSP regulatory proposals

The TEC noted that a side effect of the STPIS is that it discourages demand management solutions. Similarly, CUAC raised a concern that the STPIS encourages network investment over non-network alternatives even if non-network solutions may be more efficient.

AER considerations

The issue of the interaction between the demand management incentive scheme (DMIS) and service standards has been considered previously, in the development of the STPIS. The AER, in its final decision on the STPIS (version 1.0), noted that the removal of demand management or non network data from the application of the STPIS would lead to an increased level of risk on distribution users, and stated that:

> The AER considers that such an adjustment to the STPIS, which is fundamentally intended to maintain or improve service performance, would be inappropriate as customers should not be worse off in terms of the level of service performance they receive due to the implementation of non-network alternatives. The AER has therefore not included an exclusion for non-network alternatives as it intends that the STPIS be as neutral as possible regarding the level of reliability provided by network solutions vis-à-vis non network alternatives.
>
> The AER considers that the risks associated with the reliability of a non-network alternative should be managed by a DNSP as it is the party best able to manage that risk through the commercial arrangements it establishes in relation to non-network alternatives.[101]

The AER's position is also supported in a recent report on demand side management by the Australian Energy Market Commission (AEMC).[102] In its report, the AEMC noted that the current service incentive arrangements for distribution networks do not provide a barrier to demand side participation. The AEMC stated that service incentive schemes allow DNSPs to appropriately compare levels of reliability and continuity of supply with likely penalties or benefits. The AEMC stated that demand management options:

> will be considered, if they can improve reliability at relatively low cost rather than being summarily dismissed if they are considered less reliable. Rather, the possible penalty from a lower level of reliability will be considered and valued compared to the cost of the option and possible benefit. Therefore, if the cost of the DSP option is sufficiently low, and the risk of it impacting on the quality of supply can also be managed at a low cost, the network owner will prefer the DSP option.[103]

The AER is not aware of any compelling evidence that would lead it to alter its position on this matter. Consistent with the STPIS, the AER will therefore not exclude non-network alternatives from data collected for the purposes of applying the STPIS.

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[101] AER, Final *Decision on Service Target Performance Incentive Scheme*, June 2008, p. 19. www.aer.gov.au

[102] AEMC, *Market Review of Demand Side Participation in the NEM, Stage 2 Final Report*, December 2009 p. 32.

[103] ibid.

15.7.7 Customer service parameters

Framework and approach

The Framework and approach paper indicated that the AER would apply the telephone answering parameter in the 2011–15 regulatory control period. No further customer service parameters were proposed by the AER.

The Framework and approach paper stated:

> Targets for the reliability and customer service components of the S factor will be based on the average performance of Victorian DNSPs over the previous five years. This means the AER will take into account the previous performance of the Victorian DNSPs, as reported to the ESCV, when setting targets.[104]

Victorian DNSP regulatory proposals

Jemena proposed to base its telephone answering performance targets on the average of its performance in 2008 and 2009 as it contracted its call answering services to an external provider in May 2007.[105] Jemena indicated that the contractor utilised an automated fault message system which increased the number of calls abandoned within 30 seconds when queued for response by an operator. Jemena also stated that it believed that callers which leave the queue within 30 seconds do so because they have received the appropriate information.[106] Jemena considered that under the AER's telephone answering parameter definition, this results in lower call centre performance for 2008 and 2009. Jemena noted that the corresponding measurement under the ESCV's S factor scheme has remained substantially unchanged over the period.[107]

In its regulatory proposal, SP AusNet based its proposed telephone answering parameter target on 5 years of historical data. Further, it considered that the STPIS exclusion regime did not apply to the telephone answering parameter,[108] and therefore SP AusNet did not apply the exclusion criteria to its proposed targets.

United Energy proposed to base its targets on 2005–09 performance data.[109] United Energy considered that under the STPIS:

> Calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator are regarded as a form of failed call…[110]

CitiPower and Powercor proposed to use the average of the 2005–09 call centre performance data as targets for the forthcoming regulatory control period.[111]

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[104] AER, *Framework and approach paper*, May 2009 p. 101.
[105] Jemena, response to information requested on 3 March 2010, 19 March 2010.
[106] ibid.
[107] ibid.
[108] SP AusNet, *Regulatory proposal* p. 65.
[109] United Energy, response to information requested 3 March 2010, submitted on 22 March 2010.
[110] United Energy, *Regulatory proposal*, Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme p. 32. app.)
[111] CitiPower, *Regulatory proposal* p. 270; Powercor, *Regulatory proposal* p. 277.

CitiPower and Powercor stated in their regulatory proposals that they accept the exclusions outlined in the STPIS to apply.[112]

The targets proposed by the Victorian DNSPs in their regulatory proposals are outlined in table 15.15.

Table 15.15 Victorian DNSP proposed customer service parameter targets for 2011–15 (per cent)

Calls answered within 30 seconds	2005	2006	2007	2008	2009	2011–15 target
CitiPower	89.15	85.53	87.07	87.70	79.62	86.00
Powercor	88.73	86.53	89.28	89.84	85.71	88.00
Jemena	74.00	76.00	73.00	61.00	65.00	63.00
SP AusNet	82.70	92.20	91.16	92.30	92.00	90.08
United Energy	69.07	65.23	65.31	63.62	62.53	65.15

Source: Victorian DNSP regulatory proposals.

AER considerations

Change in definition

The STPIS definition of the telephone answering parameter differs to that applied by the ESCV which was set out in the Information specification guideline and the EDPR.[113] The EDPR contained the following guidance on the calculation of the telephone answering parameter:

> Distributors will continue to report on the proportion of calls to their fault line answered within 30 seconds and the number of occasions where the fault line is overloaded. The calls to the fault line answered within 30 seconds will:
>
> - include telephone calls answered by an IVR (interactive voice response) within 30 seconds where the IVR provides substantive information and the customer does not request to be connected to an operator; and
> - include telephone calls abandoned by the customer within 30 seconds of the telephone call being queued for response by a human operator…[114]

Under this definition, telephone calls answered by an IVR and telephone calls abandoned by a customer within 30 seconds of being queued for response by a human operator were considered successfully answered calls. This is not the case under the AER's definition, which excludes these categories from the calculation. The STPIS definition of the telephone answering parameter is:

112 ibid.

113 ESCV, *Information specification (service performance) for Victorian electricity distributors*, Issued December 2008.

114 ESCV, *EDPR 2006-10, Vol 1*, p. 31.

> Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to:
>
> - calls to payment lines and automated interactive services;
> - calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned.[115]

The Victorian DNSPs have applied differing interpretations of the AER telephone answering parameter in their regulatory proposals. It appears that:

- Jemena and United Energy have interpreted the telephone answering parameter to mean that calls abandoned within 30 seconds of being queued for response by a human operator are counted as unsuccessfully answered calls and that calls to an IVR are counted as successfully answered calls
- SP AusNet interpreted the telephone answering parameter and its proposed target on the basis of the ESCV definition
- CitiPower and Powercor interpreted the telephone answering parameter as follows:

  > …there is only a marginal difference in recalculating the historical customer service data based on the AER’s definition. Assuming the removal of calls abandoned is taken from the numerator and denominator of the calculation.[116]

Despite CitiPower’s and Powercor’s interpretation appearing consistent with the AER's telephone answering parameter definition, the proposed targets were not consistent with the AER’s calculation of the targets from information collected by the ESCV under the Information specification guideline.

A key area of confusion over interpreting the definition seems to relate to the treatment of calls to an IVR and calls abandoned within 30 seconds of being queued for response by a human operator. As set out above, the AER’s definition of the telephone answering parameter states that the ‘measure does not apply to …automated interactive services and calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator’. The AER considers this means that calls to an IVR and calls abandoned within 30 seconds of being queued for response by a human operator are to be excluded from the calculation of the parameter—that is, from the numerator and the denominator.

115 AER, *STPIS,* November 2009, p. 23.
116 CitiPower, *Regulatory proposal* p. 270; Powercor, *Regulatory proposal* 276.

The telephone answering parameter is calculated as follows:

(Calls to the fault line forwarded to an operator *less* Calls abandoned within 30 seconds of the call being queued for response by a human operator *less* Calls to the fault line not answered within 30 seconds)

divided by

(Calls to the fault line forwarded to an operator *less* Calls abandoned within 30 seconds of the call being queued for response by a human operator).

The AER recognises that the exact form of the calculation may vary depending on the data collection practices of each DNSP's call centre.

Telephone answering parameter targets

Given the differing interpretations discussed above, the AER requested clarification and further information from the Victorian DNSPs on how they calculated their proposed telephone answering parameter targets. The following section sets out the AER's assessment and considerations of the Victorian DNSPs' proposed telephone answering targets

As explained below, due to the differences between each DNSP's proposals, including the number of years of suitable data, the AER has decided to apply the telephone answering parameter on a DNSP specific basis. The AER recognises this is a departure from its likely approach set out in the Framework and approach paper that targets would be based on the average performance of Victorian DNSPs over the previous five years. However, adopting a DNSP specific approach was necessary to ensure consistency in the data upon which each DNSP's target was set, given the differences in the number of years of available data for each DNSP.

SP AusNet

In its regulatory proposal, SP AusNet stated that the STPIS exclusion regime did not apply to the call answering parameter under the STPIS.[117]

The AER notes that clause 5.4 of the STPIS states that an event excluded from the reliability of supply component of the STPIS may be excluded from the calculation of the telephone answering parameter. As the STPIS is designed to provide an incentive for DNSPs to improve performance during normal operating conditions, the AER considers that, consistent with the design of the STPIS, major event days should be excluded from call answering performance.

SP AusNet appears to have calculated its target on the ESCV definition of the telephone answering parameter.[118] In response to the AER's information request, SP AusNet applied the AER's exclusion criteria to its proposed target, however, the

[117] SP AusNet, *Regulatory proposal* p. 65.
[118] ibid.

revised target also appeared to be calculated in accordance with the ESCV telephone answering definition.[119]

In determining the appropriate target to apply to SP AusNet, the AER has used 2005–08 data provided by SP AusNet in its regulatory proposal,[120] updated for 2009 actuals.[121] The AER then calculated the target for the forthcoming regulatory control period in accordance with its methodology set out above based on the average from 2005–09.

The AER has not applied the exclusion criteria for the purpose of calculating SP AusNet's target in this draft decision as it was not able to calculate the exact impact of the exclusion regime from the information provided. However, as discussed later in this chapter, for the targets in the final decision the AER will require SP AusNet to apply the exclusions provided in the STPIS to its telephone answering data.

Jemena

Following the engagement of a new call centre operator in May 2007, Jemena was able to measure the actual number of calls abandoned within 30 seconds in 2008 and 2009. Previously, it deemed 20 per cent of all abandoned calls to be abandoned within 30 seconds in accordance with the STPIS. This change in reporting methodology resulted in a significant increase in the number of reported abandoned calls within 30 seconds, with the number increasing from 1618 in 2006 (prior to the change), to 14 430 in 2008 and 17 074 in 2009.[122]

The AER recognises the importance of setting targets in a manner consistent with how performance will be reported during the forthcoming regulatory control period. Given the significant impact of the change in reporting practices, the data recorded prior to this time is not comparable with that of 2008 and 2009.

Therefore, the AER considers that the average of the most recent two years of historical data is an appropriate base on which to set Jemena's target as it provides the most accurate data, which is calculated in a consistent manner to how Jemena currently captures this data. After a request for information from the AER, Jemena provided data consistent with the AER's telephone answering definition for 2008–09.[123] From this revised data, the AER calculated Jemena's telephone answering target for the 2011–15 regulatory control period.

In assessing the target, the AER has cross referenced the targets against information collected by the ESCV under the Information specification guideline using the abovementioned formula and found the two data sources correspond.

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119 SP AusNet, response to information requested on 9 April 2010, submitted on 28 April 2010, and SP AusNet, email, 10 May 2010

120 SP AusNet, *Regulatory proposal* p. 65.

121 Reported by SP AusNet to the AER under the ESCV's Information specification guideline.

122 As the change in reporting methodology occurred in May 2007, the 2007 figure is a combination of the old and new reporting methodologies. For completeness, the 2007 figure was 2 914.

123 Jemena, email, 12 May 2010.

The AER’s treatment of the exclusion criteria and how it applies to Jemena is discussed later in this section.

CitiPower and Powercor[124]

While CitiPower’s and Powercor’s explanation in their regulatory proposals of how they calculated their proposed targets appeared consistent with the AER’s telephone answering parameter, the proposed methodology which they applied did not appear to be consistent with the AER’s definition.

In response to the AER’s request for further information, CitiPower and Powercor resubmitted their call centre data in accordance with the AER’s definition.[125] The AER cross referenced the reported performance against information collected by the ESCV under the Information specification guideline and found that the two data sources correspond, with the exception of Powercor’s 2005 performance. The AER sought information from Powercor to reconcile the data but did not receive the information from Powercor in time for this draft decision. As such, the AER has calculated Powercor’s target from 2006–09 performance for this draft decision, but will seek to reconcile the discrepancies in the reported data and use 2005 performance data for setting the telephone answering parameter target for the final decision. The AER calculated CitiPower's targets from the further information provided by CitiPower, taking the average of its yearly performance from 2005–09.

It appears to the AER, that at the time of this draft decision, CitiPower and Powercor have not provided the actual number of calls abandoned within 30 seconds to the AER. CitiPower and Powercor will be required to provide the actual numbers so that the AER can set a more accurate target in the final determination.

The AER’s treatment of the exclusion criteria and abandoned calls for the purpose of calculating CitiPower’s and Powercor’s targets is discussed later in this section.

United Energy

As noted above, the AER does not agree with United Energy's interpretation of the telephone answering parameter. It appears that United Energy may have misinterpreted the incentive property of the parameter. In its regulatory proposal, United Energy stated that:

> United Energy has understood the implications of the differences in treatment between the two schemes, and plans to direct its efforts towards bringing down the number of abandoned calls over the forthcoming regulatory control period.[126]

Calls abandoned within 30 seconds of being queued for response by a human operator are not considered to be a type of failed call under the AER’s definition of the telephone answering parameter. As such, the AER does not consider that its telephone answering parameter provides an incentive to reduce calls abandoned within 30 seconds of being queued for response by a human operator; rather, the scheme

124 As CitiPower and Powercor calculated their proposed targets on the same basis they are assessed together for convenience.

125 CitiPower and Powercor, email, 14 May 2010.

126 United Energy, *Regulatory proposal*, Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme p. 33. app.)

focuses on providing an incentive for DNSPs to answer a call forwarded to an operator, within 30 seconds.

For 2006–09, United Energy provided information with the actual number of calls abandoned within 30 seconds of being queued for response by a human operator. The 2005 data applied an estimate of the number of calls abandoned within 30 seconds.[127] The AER considers it important that the target performance be calculated in the same manner as the performance reporting during the forthcoming regulatory control period, as discussed in the setting of Jemena's targets. Therefore, in calculating United Energy's target performance, the AER has taken an average of the performance for 2006–09 calculated in accordance with the methodology outlined above.

The AER has cross referenced United Energy's proposed targets against the information provided to the ESCV under the Information specification guideline and found the two data sources correspond.

The AER's treatment of the exclusion criteria and how it applies to United Energy is discussed later in this section.

Exclusion criteria

Clause 5.4 of the STPIS states:

> Where the impact of an event is to be excluded from the calculation of a revenue increment or decrement under the 'reliability of supply' component as provided for in clause 3.3, the impact of that event may be excluded from the calculation of a revenue increment or decrement for the 'telephone answering' parameter as appropriate.

As the proposed application of the exclusion criteria to the telephone answering parameter varied across Victorian DNSPs' regulatory proposals, the AER sought further information on how the Victorian DNSPs applied it when calculating their proposed targets.

United Energy[128] submitted information applying the AER's exclusions, however the underlying data was not consistent with the AER's telephone answering parameter definition. Although Jemena provided data in accordance with the STPIS, earlier data to which the exclusions were applied was not consistent with the STPIS.[129] CitiPower and Powercor resubmitted their call centre data in accordance with the AER's telephone answering definition, however, the exclusions were not applied.[130] SP AusNet provided information applying the STPIS exclusions but the historical performance and proposed target were calculated under ESCV's telephone answering definition.

As exclusion data was not provided in a form consistent with the AER's telephone answering definition, the AER was unable to determine the exact impact of applying

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127 United Energy, response to information requested on 9 April 2010, submitted on 3 May 2010.
128 United Energy, response to information requested on 9 April 2010, 3 May 2010.
129 Jemena, response to information requested on 3 March 2010, submitted on 19 March 2010.
130 CitiPower and Powercor, email, 14 May 2010.

the exclusion criteria to its calculated telephone answering targets. Therefore, the AER estimated the impact of applying the exclusions. The high level analysis appeared to indicate that the effect of applying the STPIS exclusions to the Victorian DNSPs' targets is likely to be immaterial. This view is consistent with Jemena's regulatory proposal which stated that, in setting its targets, Jemena did not removed major event days from the historic performance as the effect of their removal is quite small.[131] Therefore, given that the information provided to the AER from the Victorian DNSPs did not enable the AER to accurately calculate the impact of the exclusion criteria on the targets, the AER has not applied the exclusion criteria to the targets determined in this draft decision. However, the AER will require the Victorian DNSPs to provide the necessary information in order for the AER to apply the STPIS exclusion criteria to the targets in its final decision.

Abandoned calls

The STPIS sets out that where the time in which a call is abandoned is not measured, an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned.[132]

At the time of this draft decision, the AER does not have the actual number of calls abandoned within 30 seconds for each DNSP. United Energy provided the actual number of calls abandoned within 30 seconds from 2006–09.[133] Jemena provided the actual numbers for 2008 and 2009.[134] The AER's calculated targets for these DNSPs include the actual number of calls abandoned within 30 seconds SP AusNet did not provide the actual calls abandoned within 30 seconds in their regulatory proposals, in response to information requests or in information previously reported to the ESCV. For this reason, the AER assumed 20 per cent of all abandoned calls were abandoned within 30 seconds for the purpose of calculating SP AusNet's target. It appears that CitiPower and Powercor assumed 20 per cent of abandoned calls were abandoned within 30 seconds in the information they provided to the AER which was used to calculate these two DNSPs' targets.

The AER understands that the Victorian DNSPs can report the actual number of calls abandoned within 30 seconds and will require all DNSPs to resubmit targets applying actual numbers for the final decision in order for the AER to set more accurate targets for this performance indicator.

Incentive rate

Under the STPIS, the incentive rate for the telephone answering parameter is set at either –0.040 or a value determined from an applicable assessment of the value that customers attribute to the level of service proposed. None of the Victorian DNSPs proposed to deviate from the STPIS in this regard and the AER considers it appropriate to apply the default STPIS values for 2011–15 regulatory control period.

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131 Jemena, response to information requested on 3 March 2010, submitted on 19 March 2010.
132 AER, *STPIS*, p. 23.
133 United Energy, response to information requested 3 March 2010, submitted on 22 March 2010.
134 Jemena, response to information requested on 9 April 2010, submitted on 3 May March 2010.

Revenue at risk

Under the STPIS the maximum revenue at risk for all customer service parameters in aggregate is ± 1 per cent of a DNSP’s revenue for each year of the regulatory control period. The maximum revenue at risk for any individual parameter is ±0.5 per cent of revenue for each year of the regulatory control period. None of the Victorian DNSPs proposed to deviate from the STPIS in this regard and the AER considers it appropriate to apply the default STPIS values for the 2011–15 regulatory control period.

AER conclusion

The AER has calculated the telephone answering targets, in accordance with the STPIS for:

- CitiPower and SP AusNet on an average of 2005–09 telephone answering performance
- Powercor on an average of the 2006–09 telephone answering performance provided in accordance with the AER telephone answering definition
- United Energy, by using performance data from 2006–09
- Jemena, by using performance data from 2008–09.

No exclusions were applied for any of the Victorian DNSPs in the AER's calculation of their targets. The differences in the number of years upon which the AER calculated the Victorian DNSPs' targets were necessary to ensure consistency in the data upon which each DNSP’s target was set. The telephone answering parameter targets calculated by the AER in accordance with the STPIS for Victorian DNSPs are outlined in table 15.16.

The AER does not consider that its telephone answering definition substantially changes the incentives placed on Victorian DNSPs from the incentives under the ESCV's telephone answering parameter. There is still an incentive to answer calls forwarded to an operator within 30 seconds. Additionally, although calls to an IVR are no longer counted as successfully answered calls, the AER still considers there to be an incentive on Victorian DNSPs to maintain and enhance their IVR systems. If a customer receives the required information from an IVR, this should reduce the number of calls being forwarded to an operator, thus making it easier for DNSPs to answer those calls which are forwarded to an operator within 30 seconds.

The AER notes that the targets set in this draft decision should not be directly compared against the targets set by the ESCV in the current regulatory control period as the two schemes apply a different definition. Further, it would not be accurate to conclude that as the AER’s draft decision targets are a lower percentage than those proposed by the Victorian DNSPs, that the target will be easier to achieve. Again, this is due to the definitional differences between the proposed targets and the AER determined targets. Likewise, it would be inappropriate to compare a DNSP’s performance in the current regulatory control period against its performance in the forthcoming regulatory control period. The AER does not consider the incentives to improve telephone answering to be weaker under the STPIS than the incentives under the ESCV scheme.

The AER will require Victorian DNSPs to apply the exclusions provided for in clause 5.4 of the STPIS in the calculation of the telephone answering parameter target in the final determination. Further, the AER requires that the number of calls abandoned within 30 seconds be reported as the actual number of calls, where the DNSP has the ability to record the actual figure, and intends to apply the actual figure in calculating the targets in its final decision.

Table 15.16 AER calculated customer service parameter targets for Victorian DNSPs 2011–15 (per cent)

DNSP	Target performance 2011–15 calls answered within 30 seconds
CitiPower	68.94
Powercor	62.62
Jemena	57.46
SP AusNet	76.62
United Energy	58.14

Note: As discussed above, the AER expects these targets to be amended in its final decision.

15.7.8 Transitional arrangements—MAIFI definition

Framework and approach

The Framework and approach paper stated that the AER's likely approach was to apply the SAIDI, SAIFI and MAIFI reliability parameters to the Victorian DNSPs during the forthcoming regulatory control period.[135] The Framework and approach paper did not discuss the specific definitions of these parameters. The definitions of these parameters are set out in the STPIS.

Victorian DNSP regulatory proposals

All the Victorian DNSPs proposed to calculate MAIFI in a manner consistent with the current ESCV's S factor scheme,[136] which differs from the definition of MAIFI in the STPIS.

Under the AER's definition of MAIFI, each operation of an automatic reclose device is counted as a separate interruption (or MAIFI event). Under the ESCV's definition, each sequence of auto-reclose attempts resulting in a successful auto-reclose is counted as one momentary outage if the sequence is completed in no more than one

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[135] AER, *Framework and approach paper*, May 2009, p. 94.

[136] CitiPower, *Regulatory proposal* p. 263; Powercor, *Regulatory proposal* p. 269, 270. United Energy Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme) p. 34, 35. Jemena, *Regulatory proposal* p. 198, 199. SPA, email to AER 5 February 2010.

minute.[137] The Victorian DNSPs assert that if the AER's definition is applied, then reported MAIFI could significantly increase.

CitiPower and Powercor both argued that the ESCV's MAIFI definition is the only data available upon which the AER can reasonably derive future performance targets.[138] CitiPower and Powercor also stated that the application of the AER's MAIFI definition could disadvantage DNSPs that deploy automated smart network technologies. CitiPower and Powercor considered that this proposed change accords with clause 2.6 of the AER's STPIS on the basis that it is required to address a transitional issue arising from the differing definitions.[139]

Jemena also proposed to apply the ESCV definition of MAIFI, stating that its proposed amendment would align the definition with IEEE standard 1366.[140] Jemena stated that the AER's definition of MAIFI would have the impact of discouraging DNSPs from applying 'fast protection' which is designed to 'reduce the probability of sustained secondary damage resulting from transient faults, which are especially common in rural areas'.[141] Jemena stated that industry experience confirms that a multi-shot reclose function will lead to a higher success rate of the reclose operation, and that the AER's proposed definition is likely to discourage such efforts, as the multi-shot reclose process may worsen a DNSP's MAIFI results.[142]

Further, Jemena also proposed that the event definition should be modified from a 1 minute period to a 5 minute period.[143] In support of this proposed variation to the scheme, Jemena stated that its proposed variation will:

- better support developments in future self-healing networks so that remote re-configuration of the network can be further encouraged given the relaxation in time duration
- align the event with the IEEE standard
- allow current MAIFI performance data to form the basis of the targets by ensuring future performance is measured on a comparable basis.[144]

AER considerations

Clause 2.6 of the STPIS sets out the process the AER will follow in deciding the appropriateness of any proposed transitional arrangement. It sets out the following three considerations that the AER shall consider in turn:

- materiality of the issue

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137 ESCV, *Information Specification (Service Performance) for Victorian Electricity Distributors*, 1 January 2008. p. 30.
138 CitiPower, *Regulatory proposal* p. 264; Powercor, *Regulatory proposal* p. 270.
139 CitiPower *Regulatory proposal* p. 264;.Powercor, *Regulatory proposal* p. 271.
140 Jemena, *Regulatory proposal* p. 198.
141 ibid.
142 ibid., p. 199.
143 ibid., p. 197.
144 ibid., p. 197.

- reasonableness and fairness to the DNSP and customers
- consistency with the objectives as set out in clause 1.5.

The AER considers that this issue is material as the difference between the definitions (counting each attempted reclose as separate events, or one single event) is likely to have a noticeable impact on MAIFI.

The AER considers it appropriate to continue with the current MAIFI definition at this time, as counting each unsuccessful reclose event separately may alter the incentive on DNSPs to attempt to reclose an outage in the shortest possible time. The AER also considers it appropriate to continue the current definition as it is the basis upon which the Victorian DNSPs have calculated their proposed MAIFI targets for the forthcoming regulatory control period.

The AER has had regard to the objectives in clause 1.5 of the STPIS and considers that this proposed transitional arrangement gives effect to the objectives, in particular the promotion of the national electricity objective in section 7 of the NEL, and the past performance of the network.

AER conclusion

For the reasons set out above, the AER considers that the proposed amendment to retain the ESCV's definition of MAIFI, which is defined in the ESCV's Information Specification (Service Performance) for Victorian Electricity Distributors, satisfies the considerations set out at clause 2.6 of the STPIS. The AER concludes that the proposed transitional arrangement is of a material nature, and fair and reasonable having regard to both Victorian DNSPs and customers, and consistent with the objects of the STPIS set out in clause 1.5, including promoting the national electricity objective in section 7 of the NEL.

15.7.9 Adjustments to performance targets

The Victorian DNSPs proposed the following adjustments to their performance targets under clause 3.2.1 of the STPIS.

Impact of climate change

SP AusNet and United Energy stated that climate change will have an adverse effect on the performance of their networks in the forthcoming regulatory control period, and provided reports from AECOM on the likely effects of climate change on the performance of their networks due to the expected increase of the number of days with temperature above 35ºC and wind speed above 91 km/h.

As discussed in appendix L, the AER reviewed the reports complied by AECOM for SP AusNet and United Energy and considers that the predictions contained in the reports are not relevant to the performance targets set under the STPIS because

AECOM's predictions relate to changes from the 1981–2000 long term averages,[145] rather than the averages of 2005–09, on which the STPIS targets are based.

While the AER does not disagree that the climatic conditions in Victoria may be changing as predicted in the reports, it has the following concerns with respect to the application of the report in predicting short term changes and the application of the AECOM report to the data used in the proposed STPIS reliability targets:

- the annual maximum temperature anomaly in Victoria shown in the AECOM reports shows that the actual maximum temperature for the 2004–08 period (the last five years on figure 15.6) was significantly above the long term trend[146]

- in 2008, the actual number of extreme heat days was higher than the projected number for 2015[147]

- no specific analysis was provided by the DNSPs for the actual extreme heat days for 2005–09.

AECOM's studies found that three of the four models used by AECOM did not predict significant change in extreme wind gusts compared to the long term average[148]—as such, the AER is not confident that AECOM's prediction is accurate.

No specific analysis was provided by the DNSPs for the actual extreme wind days for 2005–09.

Based on the above considerations, the AER concludes that insufficient evidence was presented to justify adjustments to the performance target.

Subsequent to its regulatory proposal,[149] Jemena requested an adjustment to its MAIFI targets for the effects of climate change. Jemena stated that an increase in lightning strikes and high wind events will lead to higher MAIFI in the forthcoming regulatory control period. In its regulatory proposal, Jemena proposed a number of programs to address the effects of climate change on SAIDI and SAIFI. However, Jemena did not propose any programs aimed at reducing MAIFI and it anticipates an increase in MAIFI as a result.

Jemena referred to the AECOM report which stated that there will be an increase in the number of hot days which will lead to an increase in lightning strikes. Jemena argued that the increase in high wind days predicted in the AECOM report will also result in increased MAIFI in the forthcoming regulatory control period.

As outlined in the earlier discussion on the AECOM reports submitted by SP AusNet, the AER is not convinced that the AECOM reports can be accurately relied upon for

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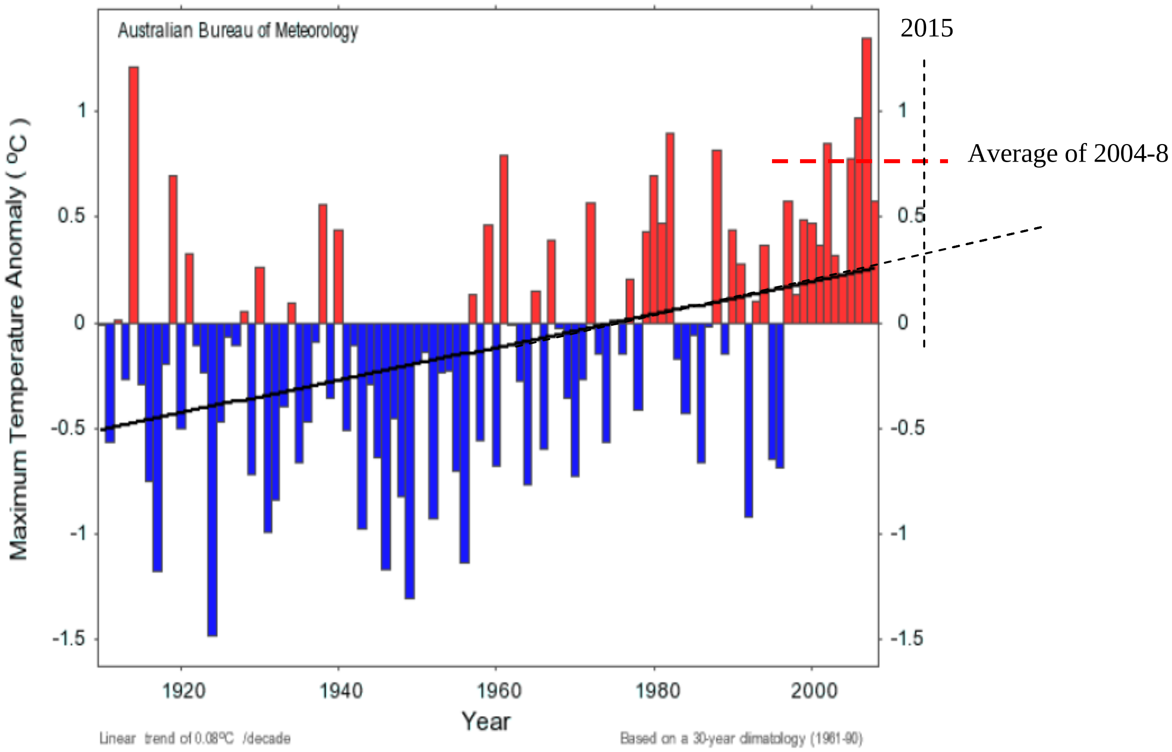
145 AECOM '*Assessment of Climate Change Impacts on SP AusNet Electricity Network for 2011-15*' p.35. and '*Assessment of Climate Change Impacts on United Energy Distribution Network for 2011-15*' p.34.
146 ibid., p. 29. and p. 29. respectively.
147 ibid., p. 35. and p. 34. respectively.
148 ibid., p. 31. and p. 30. respectively.
149 Jemena, *JEN EDPR MAIFI adjustment to baseline target*, Confidential, 30 March 2010.

predicting that 2011–15 will have more hot and windy days than 2005–09. Hence, the AER considers that Jemena did not provide sufficient justification for an adjustment to its MAIFI target.

In relation to the various climate changes adjustments to the STPIS targets proposed by SP AusNet, United Energy and Jemena, the AER will further consider whether the proposed adjustments are reasonable if further evidence is provided at a later stage. At this stage, the AER considers that predictions for short term changes in climatic conditions are subjected to potential large errors.

Figure 15.6 Annual maximum temperature anomaly—Victoria



Source: Australian Bureau of Meteorology, the AER has extended the trend line and added the average from 2004–2008

Load forecast error and probabilistic planning

United Energy requested adjustments to its performance targets to account for load forecasting error and the impact of single transformer zone substations as a result of its probabilistic planning approach.

To account for the load forecasting error, United Energy stated that 5 minutes should be added to the unplanned SAIDI target in the forthcoming regulatory control period.[150] Under clause 3.2.1(b) of the STPIS, where a DNSP proposes a performance target modification, the DNSP must provide an explanation of how the modified performance target has been calculated. United Energy did not provide an explanation as to how the 5 minutes adjustment to the performance target had been calculated.

[150] United Energy, *Regulatory proposal*, Appendix: The approach proposed by United Energy for application of the STPIS (Service Target Performance Incentive Scheme p. 19. app.)

Based on the information provided, the AER does not consider that there is any reason to make the proposed adjustment and considers that it does not better achieve the objective of the scheme. In addition, the AER considers that load forecast is part of United Energy's asset management activity, and it is not appropriate for customers to bear the risk of United Energy's asset management outcome through an explicit adjustment to the STPIS targets.

The AER does not accept United Energy's requested adjustment to the performance targets to account for the effects of probabilistic planning, specifically the higher risk due to single transformer zone substations, because of the following considerations:

- United Energy's choice for augmenting its network and to provide reliable supply is not limited by the use of single transformer zone substations. If such a substation is chosen, other measures, such as interconnection to other zone substations to achieve an overall N-1 security standard could be implemented

- United Energy has been applying probabilistic planning in the 2005–09 regulatory years, as such the effects of probabilistic planning are already factored into the performance targets

- as the purpose of the STPIS is to provide incentives to maintain and improve performance, United Energy should bear the risk of its asset management practices.

Impact of drought

United Energy submitted that the prolonged drought has caused vegetation to be more susceptible to wind damage.[151]

United Energy did not provide an explanation as to how the current drought, which has been present for much longer than the 2005–09 period—for which the performance targets are based on—would have a greater impact on network performance in the forthcoming regulatory control period. Hence, the AER is not satisfied the proposed adjustment is necessary.

15.7.10 Relationship between forecast expenditure and the STPIS

Victorian DNSP regulatory proposals

None of the Victorian DNSPs proposed any capex under the reliability improvement category in the regulatory templates in response to the AER's regulatory information notice (RIN) templates. However, chapter 8 discusses the AER's adjustments to the Victorian DNSPs' forecast capex allowance relating to reliability assumptions in their regulatory proposals.

AER considerations

The AER recognises that there is an interaction between a DNSP's capex and opex allowance and the STPIS. Clauses 6.5.6 and 6.5.7 of the NER require the AER to accept a DNSP's forecast capex or opex proposal if it reasonably reflects the capex

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151 ibid., p. 26–7.

criteria or the opex criteria. The capex criteria are cast in the context of achieving the capex objectives and likewise the opex criteria in respect of the opex objectives. It is both a capex and opex objective to maintain the quality, reliability and security of supply of standard control services.

While none of the Victorian DNSPs proposed any reliability improvement capex, the AER has identified one major project and one opex item that it considered could lead to reliability improvement. The AER's analysis of the impact of these projects is set out below.

CBD security of supply project (capex)

The ESCV approved CitiPower to undertake the CBD security of supply project to enhance the level of security of supply to the Melbourne CBD. The project was approved in February 2008, however, the majority of the construction works will be undertaken in the forthcoming regulatory control period.

The project will increase the level of supply security from the existing N-1 level of network redundancy (security) to 'N-1 secure' level. Under the N-1 Secure standard, CitiPower's network can be re-configured to withstand the loss of two elements in the 66 kV sub-transmission network.[152] Without this project, a second contingency event may result in the loss of supply to a large portion of the CBD.[153]

As part of its considerations in the approval process, the ESCV concluded that:

> it is not clear that the present structure of the [ESCV's S factor] scheme, especially in relation to the exclusion criteria, would provide any incentive for CitiPower to deliver an N-1 Secure level of security to the Melbourne CBD. This is because, if such a double contingency event did occur under the present S factor scheme, it would be excluded from S factor penalties.

The ESCV also commented that:

> a future S factor scheme should ensure that a double contingency event, of the type that N-1 Secure is designed to protect against, is not excluded from the S factor penalties.[154]

Despite the AER's scheme having a different statistical exclusion measure to the ESCV's S factor, the AER concludes that, had the CBD security of supply project not been undertaken, any double contingency event in the CBD would also be excluded under the STPIS. In forming this view, the AER has assumed that a second contingency event would result in supply interruptions to a large portion of the CBD for many hours or even weeks.[155]

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152 Essential Services Commission of Victoria, *Final Decision CBD Security of Supply*, February 2008, p. 1. As CitiPower will still require 30 minutes to reconfigure the network, there is still a risk of loss of supply to customers should the loss of a second network element occur within 30 minutes of the first network element outage. If the loss of the second element occurs more than 30 minutes after the loss of the first element, there would be no loss of supply to customers.

153 ibid., p. 5.

154 ibid., p. 10–11.

155 Essential Services Commission, *Review of CitiPower CBD security of supply proposal:* Issues Paper, July 2007, p. 20.

The AER sought specific information from CitiPower regarding whether it experienced any second contingency events in the past five years which resulted in supply interruptions to CBD customers whose level of supply will be enhanced by the CBD security of supply project. CitiPower advised that no such event occurred.[156]

The AER concludes that, as a second contingency event did not form part of CitiPower's historical performance indicator for the purpose of setting the performance targets for the STPIS; and any future such event will be excluded from the performance measures for the purpose of the STPIS; there is no need to adjust CitiPower's performance targets.

The AER will consider whether security of supply measures should form part of the STPIS at the next review of the scheme.

Proposed amendments to the Electricity Safety (Electric Line Clearance) Regulations 2005 (opex)

As a result of Energy Safe Victoria's (ESV's) review of the current network safety regulations, it proposed a number of changes including the Electricity Safety (Electric Line Clearance) Regulations. Victorian DNSPs sought additional opex to allow for the proposed changes in the regulation. Details of the proposed opex and the AER's considerations are discussed in appendix L.

The AER sought specific information from ESV regarding the expected impact on reliability of electricity supply as result of the proposed regulatory changes. ESV advised that given the time delay in improvements, in particular around insulated powerlines where the proposed changes have significant impact, it does not consider the proposed changes in line clearing regulations would have a material impact on network reliability in the short term.[157]

Based on ESV's advice, the AER considers that there are no obvious reasons to adjust the performance targets for this proposed change in regulation.

AER conclusion

The AER concludes that, while many aspects of the Victorian DNSPs' capex and opex influence the level of network reliability in the long term, the capex and opex allowances provided for in this draft decision do not include expenditure that is designed to enhance network reliability. The conclusion not to amend the STPIS targets in response to these projects is consistent with the AER's assessment of, and decision on the DNPS' proposed opex and capex proposals pursuant to clauses 6.5.6 and 6.5.7 of the NER respectively.

15.7.11 Performance targets

The AER has assessed the various proposed adjustments to the calculation of the performance targets at sections 15.7.5, 15.7.7 and 15.7.9 of this draft decision. The AER has reviewed the calculations of the proposed STPIS targets and has not identified any material issues, and has made only minor adjustments set out below.

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[156] CitiPower, response to information requested on 3 March 2010, submitted on 12 March 2010.
[157] ESV, response to information requested on 19 March 2010, submitted on 23 March 2010.

The AER has verified that the historical performance figures (upon which the DNSPs' proposed targets are based) correspond to the audited performance data that is submitted to the AER in accordance with the ESCV's information specification (service performance) guideline for Victorian electricity distributors.

The only proposed deviation from the STPIS that the AER has allowed is the continuation of the ESCV's definition of the MAIFI parameter. The AER amended Jemena and United Energy's targets as the AER did not accept their calculations of the MED threshold,[158] and amended SP AusNet's targets to correct for an apparent spreadsheet error which lead to SP AusNet not excluding the effect of transmission outages from its historical figures upon which its proposed targets were based. Finally the performance targets for SP AusNet and Powercor were recalculated to reflect a MED threshold set 2.8 beta from the mean.

Table 15.17 sets out the AER's draft decision on the performance targets to apply to the DNSPs in the forthcoming regulatory control period. These performance targets have been expressed to four degrees of significance to provide accurate targets, and commensurate revenue outcomes.

Table 15.17 AER conclusion on performance targets for SAIDI, SAIFI and MAIFI

	CitiPower	Jemena	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI (average minutes)	11.27	–	–	–	–
SAIFI (average interruptions)	0.186	–	–	–	–
MAIFI(average interruptions)	0.026	–	–	–	–
Urban	–	–	–	–	–
SAIDI (average minutes)	22.36	68.50	82.47	105.62	55.09
SAIFI(average interruptions)	0.450	1.127	1.263	1.520	0.899
MAIFI(average interruptions)	0.175	0.776	1.412	2.519	1.074
Short Rural	–	–	–	–	–
SAIDI (average minutes)	–	153.15	114.81	214.73	99.15
SAIFI(average interruptions)	–	2.588	1.565	2.697	1.742
MAIFI(average interruptions)	–	1.940	2.881	5.421	2.122
Long rural	–	–	–	–	–
SAIDI (average minutes)	–	–	233.76	267.10	–
SAIFI(average interruptions)	–	–	2.540	3.378	–
MAIFI(average interruptions)	–	–	6.535	8.996	–

Source: AER analysis.

15.7.12 True-up of the ESCV's S factor scheme

Framework and approach

In the Framework and approach paper, the AER noted that the financial benefits and penalties accrued in the current regulatory control period under the ESCV S factor scheme will not be incorporated in the price cap formula. Rather, financial carryover amounts from the current regulatory control period will be included as a building block element in the calculation of allowed revenue for the forthcoming regulatory control period.[159] The Framework and approach paper did not consider the specific implementation of a method to close out the ESCV's S factor scheme.

159 AER, *Framework and approach paper*, May 2009, p. 94.

Victorian DNSP regulatory proposals

All Victorian DNSPs proposed an approach to closing out the ESCV S factor scheme in their regulatory proposals. The Victorian DNSPs also provided spreadsheets containing models of their respective approaches.

CitiPower and Powercor stated that:

> Clause 6.4.3(a)(6) of the Rules provides that one of the building blocks is the revenue increments or decrements (if any) for the regulatory year 'arising from the application of a control mechanism in the previous regulatory control period'. The intention of this provision is to allow the AER to carry over amounts arising under the ESCV's s factor scheme from the 2006-2010 period when making its determination for the next regulatory control period.[160]

Jemena stated that it developed a method that:

- assesses all the anticipated S factor increments and decrements by year over the 2011 to 2018 period
- turns these into present value for the inclusion in JEN 2011-15 building block revenue requirement.[161]

Jemena also stated that identifying the S factor increments and decrements over the 2011 to 2017 period required it to determine what revenue stream these should apply to in order to establish the required building block adjustments. Jemena investigated two methods:

- adjusting revenue streams and applicable incentive rates for the Po and X factors
- rolling forward 2010 revenues for CPI and weighted average growth in order to avoid the need for P0 and X factor adjustment.
- JEN considers the latter method to be preferable as it avoids the need for JEN to iterate between the true-up calculation and the P0 and X factors. This significantly simplifies the calculation without diminishing the accuracy of the true-up computation.[162]

Further, Jemena stated:

- the true-up requires JEN to estimate actual 2010 service performance which will not be know in time for the AER determination. To mitigate any risks associated with this, Jen proposes a correction formula to apply to 2012 prices for differences between estimated and actual performance.[163]

United Energy did not concur with the AER's position in its Framework and approach paper, stating that:

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160 Powercor, *Regulatory proposal* p. 265. CitiPower, *Regulatory proposal* p. 260.
161 Jemena, *Regulatory proposal* p. 203.
162 ibid., p. 204.
163 ibid., p. 204.

- For United Energy, the carry forward from 2012 to 2018 is comprised of both obligations (penalties to be paid) and entitlements (rewards). United Energy assumes that the S factor to be applied to tariffs in 2011 will be calculated in accordance with the old scheme. United Energy proposes to bank the negative value for S"t that will be reported for 2011.[164]

In order to close out the ESCV S factor scheme, United Energy proposed the following steps:

- An S factor, calculated under the old scheme, should indeed be applied to the price control formula in 2011. The results for S't and S't-6 will be approximately as shown in table 1-8, subject to revisions to the ROS (reliability of supply) and CS (customer service) performance measures for 2009. Separate annual performance and carry forward components should be calculated. Lest there be any doubt, the full ESCV scheme should apply for the 2011 calendar year, even though 2011 is in the new regulatory control period. Note also that United Energy proposes to use the banking facility in 2011.

- The complete ESCV scheme should, in effect, also be applied to the price control formula for calendar 2012, albeit with modifications. The modifications will have the effect of closing the scheme off completely.

- The AER STPIS should take effect from the 2013 calendar year. An S factor calculated under the new STPIS scheme will incorrectly affect tariffs from 2013. The S factor calculation for 2013 will depend upon the results for the ROS and CS performance measures in 2011.

- In nominal, undiscounted terms, the carry-over values from 2017 to 2018 will be affected by the decision about whether or not to bank the percentage result for the raw S factor, S"t in 2011. However, there is no impact from banking on the NPV of the carry-over series in 2012.165

SP AusNet stated that, in calculating the payout amount for the S factor, account needs to be taken of the complexity of the scheme and that its operation in the current period can affect future revenues. According to SP AusNet, its model takes account of:

- the asymmetry that is inherent in the ESCV S Factor scheme;

- the fact that after S Factor adjustments are removed from prices after the six year payment period, a proportion remains embedded in revenues; and

- the gap analysis that underlies the S Factor regime (in contrast to the performance against target analysis underlying the STPIS). A gap analysis relies on performance returning to an underlying level over time. As the regime ceases to exist 2010, the last year of the regime can either penalise or benefit the company permanently due to the fact performance will not return to underlying. To counter this, 2011 performance equal to

164 United Energy, *Regulatory proposal*, Appendix: Closing out the ESCV S factor Scheme p. 14.
165 ibid.

the underlying reliability performance must be assumed after the 2010 result is accounted for. [166]

AER considerations

The AER has assessed the models provided by all Victorian DNSPs to close out the ESCV S factor, and has determined that CitiPower, Powercor and Jemena have proposed an appropriate methodology for determining the benefits and penalties accrued in the current regulatory control period under the ESCV S factor scheme. The AER considers that as the ESCV S factor scheme was applied uniformly to all Victorian DNSPs, it is appropriate the methodology to close out the S factor scheme also be applied uniformly.

After assessing all the proposed models, the AER has adopted, with minor variation, the methodology proposed by CitiPower, Powercor and Jemena. The AER intends to apply this methodology to all Victorian DNSPs.

The AER considers that the method of forecasting future tariff revenue used by CitiPower, Powercor and Jemena is appropriate as it appears to reflect the intent of the ESCV's S factor scheme. However, the AER notes that it has updated these forecasts with the demand forecasts approved by the AER in its draft decision. The AER also considers the manner in which these DNSPs calculated the S factor appears to accurately reflect the ESCV's S factor scheme. The AER notes that there are some minor variations between these methodologies, however, the AER does not consider the differences to be material.

United Energy's proposed methodology is not consistent with the Framework and approach paper in that it does not propose to close out the ESCV's S factor payments through the building blocks. Rather, United Energy proposed to apply the S factor, calculated under the ESCV's scheme, to the price formula in 2011 and with some modifications from 2012 onwards. This differs from the approach set out in the Framework and approach paper, which states that the impact of the S factor scheme is to be removed from the price control formula and incorporated into the building blocks. While the AER considers United Energy's approach to closing out the S factor scheme results in a similar net present value, the AER considers that its approach is preferable as it is more transparent and consistent with both its Framework and approach paper and clause 6.12.3(c) of the NER. The AER has therefore amended United Energy's methodology, to close out the S factor scheme, to reflect the position in the Framework and approach paper and to be consistent with its treatment of the other Victorian DNSPs.

SP AusNet used a historical relationship between revenue and energy demand to forecast the revenue base going forward. The AER considers that a more appropriate methodology is to use the approved 2010 tariff prices multiplied by the approved demand forecasts from the AER's final determination (an approach it has applied to the other Victorian DNSPs). This calculation excludes the effects of both the ESCV's S factor scheme and AER's STPIS, which the AER considers is an appropriate revenue forecast to use in calculating the enduring effects of the ESCV's S factor scheme.

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[166] SP AusNet, *Regulatory proposal* p. 72.

SP AusNet also proposed that performance estimates for 2011 be included in the model to close out the S factor scheme and that this performance estimate should be equal to the underlying reliability performance. SP AusNet considered that:

> as the regime ceases to exist 2010, the last year of the regime can either penalise or benefit the company permanently due to the fact performance will not return to underlying.[167]

The AER considers that this step is not necessary and will not incorporate it into its methodology for the following reasons:

- there is no certainty that SP AusNet’s performance in 2011 will represent the underlying trend
- SP AusNet's performance in 2011 will be influenced by the STPIS resulting in its 2011 performance not being reflective of the effects of the previous ESCV's S factor scheme
- the ESCV’s S factor scheme has been in operation for five years between 2006–10. The AER considers that this timeframe is sufficiently long to be reflective of SP AusNet’s performance trend.

After considering the approaches suggested by all Victorian DNSPs, the AER has determined that the methodology proposed by CitiPower, Powercor and Jemena is appropriate (subject to minor modification). The AER has updated the forecast tariff revenue with the approved demand forecasts for the 2011–15 regulatory control period contained in this draft decision.

The methodology the AER proposes is:

1. The DNSPs' reliability performance for 2010 is estimated as the actual performance will not be known until part way through 2011.[168] The AER considers that an appropriate estimation methodology to use is the average performance over the past five years (2005–2009).
2. S”t is calculated for 2009 and 2010 in accordance with the ESCV's S factor scheme.
3. S’t for 2011 and 2012 is calculated by banking S”t in accordance with the DNSPs' stated intentions.[169] The WACC to apply in the banking calculation is the 2006–10 EDPR WACC.
4. S’t for 2013–2018 is held constant at 0.
5. St is calculated for 2010–2018 in accordance with the ESCV's S factor scheme. The AER notes that St and S't-6 become zero after 2018 and at this time the effects of the ESCV’s S factor scheme have been fully accounted for.

[167] ibid.

[168] The AER has included actual 2009 figures provided by the Victorian DNSPs, but has not assessed the results. The AER will undertake this assessment prior to publishing its Final Decision.

[169] Consistent with the current operation of the ESCV's S factor scheme, the Victorian DNSPs will be able to make a final decision whether or not to use the s-bank mechanism when setting tariffs for 2012.

6. The estimates of forecast revenue are to be the approved 2010 tariff prices multiplied by the demand forecast. For the years 2016–18, forecast revenues are to be held constant at 2015 levels.
7. The S factor is applied to the forecast revenues for 2011–18. For 2011–15, the difference between the estimates of tariff revenues, excluding and including the S factor is then factored into the building blocks.
8. The difference between the estimates of tariff revenues, excluding and including the S factor, for 2016–18 are converted to 2015 values in net present value terms and applied to the building blocks in 2015. The WACC to apply to this NPV calculation is the 2011–15 EDPR WACC.

Availability of 2010 actual performance outcomes

The AER notes that, in order for the methodology, to close out the S factor scheme, to accurately close out the previous scheme, the actual performance for 2010 is required. This information will only be available in the first quarter of 2011, after the publication of the AER's final determination.

The value for closing out the previous S factor scheme calculated in accordance with the above methodology uses an estimate of the 2010 performance. Therefore, a final adjustment will be required to accurately reflect the actual 2010 performance of the DNSPs. The Victorian DNSPs proposed that this reconciliation should be done as either a pass through or added as an additional parameter in the price control formula in 2012.

The AER notes that this reconciliation was not included in the form of control as set out in the Framework and approach paper. As discussed in chapter 4 of this draft decision, the AER does not consider a pass through is appropriate. Further, given the constraints in the NER on amending the form of control, from that specified in the Framework and approach paper, the AER also considers that the addition of a parameter in the price control formula is not appropriate. Therefore, the final reconciliation of actual 2010 performance under the ESCV S factor scheme will be addressed in the 2016–20 distribution determination.

AER conclusion

Based on the above analysis, the AER will close out the ESCV's S factor scheme applying the methodology set out above.

The AER considers that the appropriate adjustments to the building blocks are as set out in table 15.18. The AER notes that it will need to update these values, for the final decision, to incorporate actual 2009 performance, updated estimates of 2010 performance and any changes to the DNSPs' demand forecasts.

Table 15.18 AER conclusion on the building blocks resulting from the ESCV S factor true-up ($ million, 2010)

	2011	2012	2013	2014	2015
CitiPower	0.15	–2.82	–3.32	–0.22	–6.89
Powercor	16.25	–7.57	–4.49	0.78	–28.71
Jemena	–2.17	0.27	0.74	0.76	0.40
SP AusNet	19.97	2.33	–5.11	0.83	–46.80
United Energy	–4.95	–18.81	–17.76	–18.15	–41.96

Note: Based on forecast network performance for 2009 and 2010 provided in the respective regulatory proposals. The AER will adjust these figures for the final decision based on actual 2009 performance and an updated estimate of 2010 performance.

Source: AER analysis.

15.7.13 Implementation of the S factor

The STPIS will apply to the Victorian DNSPs from the commencement of the forthcoming regulatory control period. As the 2011 performance will only be available in the first quarter of 2012, the S factor result of 2011 will be incorporated into the Victorian DNSPs' distribution tariff models for 2013 in their tariff approval submissions at the end of 2012.

The two year delay between the actual performance and price impact is inevitable and is part of the design of the STPIS.

As such, for the purpose of the distribution tariff calculation, the S_t factor applied to the Weighted Average Price Cap formula for 2011 and 2012 will be zero. The Weighted Average Price Cap formula is specified in section 4.6.1 of the draft decision.

15.7.14 Guaranteed service level

Guaranteed service level (GSL) payments currently apply under the Electricity Distribution Code (EDC) and Public Lighting Code (PLC) in Victoria. The AER's STPIS states that, where jurisdictional electricity legislation imposes an obligation on a DNSP to provide GSL payments, the AER's GSL scheme will not apply to that DNSP.

Framework and approach

The AER stated in its Framework and approach paper that based on advice from the Department of Primary Industries (DPI), it understood that the Victorian GSL scheme provided for under the EDC and the PLC would cease to apply at the end of the current regulatory control period.[170]

[170] AER, *Framework and approach paper*, p. 99.

Therefore, the AER stated that its likely approach would be to apply all parameters under the GSL component of the AER's STPIS to the Victorian DNSPs in the forthcoming regulatory control period.

Victorian DNSP regulatory proposals

The Victorian DNSPs’ regulatory proposals varied in calculating the forecast GSL payments for the forthcoming regulatory control period. This suggests that there was uncertainty about whether the existing GSL scheme would continue to apply in the 2011–15 regulatory control period.

Jemena proposed not to apply the GSL parameter under the AER's scheme requiring DNSPs to notify customers four days in advance of planned interruptions in its regulatory proposal. Jemena stated that while it currently has the obligation to notify customers of planned interruptions, it has not previously had the obligation to verify whether the notification has been received by the customer.[171] Jemena stated that it does not currently have in place systems to measure adherence to this parameter and that the costs of deploying such a system would outweigh the benefits.[172]

Submissions on DNSP regulatory proposals

The Minister submitted that as part of the determination, the AER should review whether the GSL payment thresholds should be amended to ensure that the payments continue to be made to the worst served 1 per cent of customers. The Minister also submitted that the AER should review whether the level of GSL payments should be amended to reflect the latest VCR.[173]

Clarification with the Jurisdiction

At the time that the Victorian DNSPs submitted their regulatory proposals, the AER had not received any confirmation from DPI regarding the status of its GSL scheme. Subsequently, the AER informed DPI that, unless the status of the GSL regulatory obligations under the EDC and PLC are clarified, it will assume the existing GSL obligations under these codes will remain after 2010.

The AER also informed the Victorian DNSPs of its intention to continue the ESCV's scheme and requested the forecast GSL payments for the 2011–15 regulatory control period calculated under the scheme.

DPI advised that the Victorian Government is of the view that service standards and service incentive mechanisms (including GSL payments) are intrinsic to the price/service trade-off that is an economic regulatory function. It noted that, historically, the GSL payment scheme has been determined as part of electricity distribution price reviews and then reflected in the appropriate regulatory instruments. DPI advised that it expected that the AER will determine the appropriate GSL payments for Victorian electricity customers for the 2011–15 regulatory control period.

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171 Jemena, *Regulatory proposal* p. 201.
172 ibid.
173 Minister for Energy and Resources, *Submission to the AER*, p. 7.

AER considerations

Unless the existing GSL obligations are repealed, the AER must apply the Victorian GSL scheme in the 2011–15 distribution determination as required under clause 6.6.2(b)(2) of the NER, and clauses 2.1(c) and 6.1 of the STPIS.

The AER may review the Victorian GSL scheme and propose amendments to the EDC and the PLC to the ESCV under section 27 of the *National Electricity (Victoria) Act 2005*. However, this process is separate from the AER making the Victorian distribution determinations.

The AER's preference is to apply the national GSL scheme contained in the STPIS to the Victorian DNSPs because although the national scheme is similar to the existing Victorian scheme, the AER’s scheme has the same exclusion criteria as the STPIS S factor for supply interruption events on MED days, whereas the EDC GSL scheme applies the 2006–10 EDPR MED exclusion threshold. This may lead to potentially inconsistent incentive outcomes between the S factor and the GSL scheme.

The AER has contacted the ESCV to request it amend the EDC in order to enable the application of the national GSL scheme. If this process is completed prior to the final determination, the AER intends to apply the national STPIS in its entirety to Victorian DNSPs in the forthcoming regulatory control period.

The AER expects that the differences between the existing GSL scheme and the national scheme would not be considerable in terms of the overall opex of the DNSPs. However, if the Victorian GSL scheme is repealed, the AER will review the forecast opex requirement for GSL payments.

The STPIS requires that the AER determine the threshold to apply to each applicable GSL parameter and the payment amount to apply to the applicable GSL parameter. In this draft determination, the AER is implementing the ESCV's GSL scheme and therefore is not able to alter the threshold or payment amounts from the ESCV’s GSL scheme. As such, the AER will apply the thresholds and payments outlined in the EDPR and the PLC.[174]

As explained above, not all Victorian DNSPs provided their forecast GSL expenditures under the national GSL scheme. Further, as the AER proposes a different MED threshold for Powercor and SP AusNet, the AER is unable to accurately estimate the overall GSL expenditures for the DNSPs at this stage. The AER will seek the DNSPs to provide accurate forecast should the ESCV repeal the GSL obligations under the EDC.

Regarding the Minister’s submission to review the GSL payment framework for Victoria, as discussed above, the AER is bound to apply the Victorian GSL scheme in the forthcoming regulatory control period and can only apply the national GSL scheme if the ESCV revokes the EDC GSL obligation following the AER’s request.

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[174] ESCV, *EDPR 2006-10*, Final Decision Vol. 1, pp.75 - 76.

Exemption from notice of planned interruptions GSL parameter

As part of its regulatory proposal, Jemena requested an exemption from the ‘notice of planned interruptions’ GSL parameter. This GSL parameter requires Jemena to notify customers at least four days prior to any planned interruption. This GSL parameter only applies under the STPIS and not under the ESCV's GSL scheme.

According to Jemena, it currently notifies customers of planned interruptions via card drops in letter boxes, dropped by a contractor on its behalf. It does not keep records as to whether individual customers have been notified. In its proposal, Jemena stated that the costs of adding this GSL requirement are likely to outweigh the benefits.[175]

The AER considers that it is appropriate to apply the GSL parameter requiring at least four days notification prior to planned outages should the AER's GSL scheme apply in the forthcoming regulatory control period. DNSPs would be expected to maintain adequate records to show that they are compliant with this regulatory obligation. Further, no other DNSP has requested an exemption from this GSL parameter. The notice of planned outages GSL parameter will apply to Jemena if the AER's GSL scheme applies in the 2011–15 period.

AER calculation of forecast GSL payments

On request from the AER, Victorian DNSPs provided their forecasts of GSL payments under the ESCV’s GSL scheme. Different methods for forecasting GSL payments were proposed by the Victorian DNSPs. The AER has reviewed the forecast GSL payments against the operating expenditure requirements under clause 6.5.6 of the NER. The forecast payments have not been adjusted by the CPI as the payments are fixed in the EDC and PLC. The AER has applied a consistent approach to forecasting GSL payments drawing on aspects of the various proposed approaches.

The AER proposes to use an average of historical GSL payments as the basis for the number of forecast GSL payments in the forthcoming regulatory control period. The AER considers it appropriate to base the forecasts upon 2005–09 data where available and appropriate, and 2006–09 data elsewhere.

In 2006, a new GSL scheme was developed by the ESCV with new GSL parameters. The GSL parameters for ‘arriving on time for appointments,’ ‘streetlights’ and ‘connection on agreed date’ remained unchanged from the earlier GSL scheme and therefore data from 2005 can be used to forecast future GSL payments for such parameters.

Several DNSPs voluntarily paid some GSL payments for events that are exempted from such payments. The AER must consider the efficient costs of achieving the operating expenditure objectives and cannot provide funding for additional voluntary GSL payment amounts. Forecast GSL payments are to be based upon specified payment obligations for each GSL parameter set in the EDC and the PLC.

To calculate the GSL forecast payments for all Victorian DNSPs, the AER determined the average number of payments from 2005–09 (or 2006–09) and then applied the

[175] Jemena, *Regulatory proposal,* p. 201.

payment amounts specified in the EDPR to each year. The average of the yearly payments was used to forecast the GSL payments for the 2011–15 regulatory control period. The AER will include the forecast GSL payments as a line item in the opex allowance for each year in the forthcoming regulatory period.

Each of the different forecasting methodologies applied by the DNSPs—based on the assumption that the existing GSL scheme will continue—are outlined below together with the AER's reasons for accepting, or rejecting, the proposed approaches.

CitiPower and Powercor

CitiPower and Powercor based their forecast of the number of GSL payments on the number of payments made in 2009. For Powercor, the total GSL payments in 2009 was over 100 per cent higher than the average of payments in the previous three years.

The AER does not accept CitiPower's and Powercor's forecast of GSL payments based upon the 2009 year as GSL payments in this year appear abnormally high. Consistent with the approach to be applied to the other Victorian DNSPs, the AER will apply an average of the payments from 2005–09 instead. Also, the AER does not accept the application of the customer growth factor which CitiPower and Powercor applied to its forecasts. CitiPower and Powercor have not provided justification for the application of the growth factor by demonstrating that customer growth will impact on forecast GSL payments.

Additionally, CitiPower and Powercor have applied a CPI adjustment factor to the value of their 2009 GSL payments so that the values are expressed in 2010 dollar terms. The AER does not accept the application of a CPI adjustment to forecast GSL payments as the amount of these payments is set in the EDC and is not indexed to inflation.

Table 15.19 AER conclusion on GSL payments for CitiPower ($, nominal)

GSL parameter	Forecast number	Forecast payments
15 minutes late for an appointment	2	36
Connections not made on agreed date total	18	2 584
Connections not made—1–4 day delay	17	2 034
Connections not made—5+ day delay	1	550
20 hours of interruptions	106	10 575
30 hours of interruptions	14	2 025
60 hours of interruptions	–	–
10 interruptions	–	–
15 interruptions	–	–
30 interruptions	–	–
24 momentary interruptions	–	–
36 momentary interruptions	–	–
Streetlights	25	250
Total		**15 470**

Source: AER analysis.

Table 15.20 AER conclusion on GSL payments for Powercor ($, nominal)

GSL parameter	Forecast number	Forecast payments
15 minutes late for an appointment	5	96
Connections not made on agreed date total	51	9 570
Connections not made—1–4 day delay	45	7 120
Connections not made—5+ day delay	6	2 450
20 hours of interruptions	7 029	702 850
30 hours of interruptions	911	136 688
60 hours of interruptions	84	18 975
10 interruptions	2 153	215 300
15 interruptions	8	1 238
30 interruptions	–	–
24 momentary interruptions	2 570	64 238
36 momentary interruptions	766	26 793
Streetlights	41	408
Total		**1 176 156**

Source: AER analysis.

Jemena

Jemena based its reliability, appointment and connection GSL forecasts on data from January 2008 to July 2009 on the basis that 2008 and 2009 had adverse weather conditions, which it stated will continue due to climate change.[176] As discussed in section 15.7.9, Jemena has not provided sufficient evidence that supports its claim that weather condition for 2011–15 will be materially worse than the 2006–10 regulatory control period, therefore the AER does not accept this method of forecasting GSL payments. Consistent with the approach applied to other GSL forecasts, the AER considers that a forecast based on an average of historical payments over the previous four or five regulatory years where appropriate is more accurate.

Jemena applied the AER MED exclusion criterion in the STPIS to the 2009 data for its forecasts of the reliability GSL. The 2009 reliability GSL as calculated under the ESCV scheme was also provided although not used in the forecasts.[177] The AER considers that it is not appropriate to apply the AER's MED threshold when calculating forecast GSL payments as it will not represent an accurate forecast of the payments expected to be made under the Victorian GSL scheme. Instead, the AER has

176 Jemena, response to information requested on 1 February 2010, submitted on 16 March 2010.
177 ibid.

forecast GSL payments using regulatory data that includes the effects of MED days under the Victorian GSL scheme.

Jemena used 2004–08 data with the exclusion of the 2009 data when estimating forecast streetlight GSL payments.[178] For streetlight repair, Jemena noted that there were abnormally high payouts in 2009 due to 'internal business process change.' Jemena proposed that the 2009 data not be used as a result. Though there are an abnormally high number of streetlight payments in 2009 totalling 139, this only amounts to $1 390 dollars worth of GSL payments. The AER does not consider that this amount is material enough to warrant a deviation from the consistent forecasting approach. Consistent with the approach applied to the other Victorian DNSPs the AER will forecast GSL payments based upon the average of 2005–09 GSL payments.

Table 15.21 AER conclusion on GSL payments for Jemena ($, nominal)

GSL parameter	Forecast number	Forecast payments
15 minutes late for an appointment	6	112
Connections not made on agreed date total	28	3 740
Connections not made—1–4 day delay	25	2 650
Connections not made—5+ day delay	3	1 090
20 hours of interruptions	141	14 050
30 hours of interruptions	3	375
60 hours of interruptions	–	75
10 interruptions	–	–
15 interruptions	–	–
30 interruptions	–	–
24 momentary interruptions	–	–
36 momentary interruptions	–	–
Streetlights	54	540
Total		**18 892**

Source: AER analysis.

SP AusNet

SP AusNet based its forecast GSL payments on an average of 2005–09 payments where the data is available and indexed the forecast payments by the forecast increase in the number of new customer connections.

[178] ibid.

The AER accepts using an average of the 2005–09 payments as a forecast for future GSL payments.

Regarding SP AusNet's proposed adjustment for customer growth, the AER notes that during the 2005–09 period, there has been significant fluctuation in the number of GSL payments made by SP AusNet, while growth in the number of its customers has remained fairly steady over the period. This suggests that the change in customer numbers is not a strong driver of GSL payments. Furthermore, applying a growth forecast to GSL payments ignores performance improvements that may be expected as a result of the incentive provided by both the GSLs and STPIS. As SP AusNet has not demonstrated that there is a causal relationship between the forecast number of customers and the number of GSL payment events, the AER does not consider it appropriate to base the forecast number of payments on the number of customers.

Table 15.22 AER conclusion on GSL payments for SP AusNet ($, nominal)

GSL parameter	Forecast number	Forecast payments
15 minutes late for an appointment	2	32
Connections not made on agreed date total	262	27 600
Connections not made—1–4 day delay	229	19 150
Connections not made—5+ day delay	34	8 450
20 hours of interruptions	13 229	1 322 925
30 hours of interruptions	6 731	1 009 613
60 hours of interruptions	1 763	528 900
10 interruptions	8 237	823 650
15 interruptions	1 966	294 863
30 interruptions	–	–
24 momentary interruptions	9 367	234 169
36 momentary interruptions	2 786	97 501
Streetlights	4	42
Total		**4 339 295**

Source: AER analysis.

United Energy

United Energy noted that it would prefer to apply the parameters under ESCV's GSL scheme rather than the STPIS GSL scheme.[179] United Energy's general approach to forecasting its GSL payments was to apply a straight average of six previous years'

179 United Energy Distribution, *Regulatory proposal*, Appendix A3, RIN templates 6.6, confidential, 30 November 2009, p. 2.

payments.[180] The AER considers that an average of the previous GSL payments is an appropriate basis for forecasting GSL payments. However, consistent with the approach applied to forecasting GSL payments of the other Victorian DNSPs, an average of 2005–09 data where available has been used to forecast future GSL payments.

United Energy applied the AER exclusion criteria when forecasting the SAIDI and SAIFI GSL payments (number and duration of interruptions).[181] As the STPIS GSL payments will not be applied in the forthcoming regulatory control period, the AER considers that exclusions applied under the ESCV GSL scheme should apply to forecasts instead. In forecasting future SAIDI GSL payments for United Energy, the AER has removed the effect of the AER's GSL exclusion criteria.

Table 15.23 AER conclusion on GSL payments for United Energy ($, nominal)

GSL parameter	Forecast number	Forecast payments
15 minutes late for an appointment	30	592
Connections not made on agreed date total	72	7 234
Connections not made—1–4 day delay	64	4 874
Connections not made—5+ day delay	10	2 360
20 hours of interruptions	2 071	207 075
30 hours of interruptions	237	35 475
60 hours of interruptions	34	10 200
10 interruptions	61	6 050
15 interruptions	–	–
30 interruptions	–	–
24 momentary interruptions	–	–
36 momentary interruptions	–	–
Streetlights	18	184
Total		**266 810**

Source: AER analysis.

Comparison of the AER's forecast annual GSL payment levels with the 2006–10 EDPR

Table 15.24 shows the comparison of the AER's forecast annual GSL payments for each DNSP compared with that determined by the ESCV under the 2006–10 EDPR. This table shows that, except for CitiPower, the AER's forecast GSL payment levels are similar to those previously estimated by the ESCV.

180 ibid.

181 United Energy, response to information requested on 4 February 2010, submitted on 7 April 2010.

The AER considers that, because of the relatively small geographic size of CitiPower, it is more susceptible to localised weather events than the larger DNSPs.

The AER concludes that, pursuant to clause 6.5.6(a)(2) of the NER, it will include its forecast total GSL payments in table 15.24 as a line item in the opex allowance, for each year in the forthcoming regulatory period.

Table 15.24 AER conclusion on annual total GSL payments compared with 2006–10 EDPR ($, nominal)

DNSP	AER forecast	ESCV's forecast in 2005
CitiPower	15 470	1000
Powercor	1 176 156	1 283 000
Jemena	18 892	17 250
SP AusNet	4 339 295	4 314 500
United Energy	266 810	254 000

Source: Essential Services Commission, Electricity Distribution Price Review 2006-10, Final Decision Volume 1 Statement of Purpose and Reasons, p.76.

15.8 AER conclusion

This chapter sets out the AER's considerations and reasons for its draft decision as to how the STPIS is to be applied to the Victorian DNSPs in the forthcoming regulatory control period.

In making its constituent decision pursuant to clause 6.12.1(9) of the NER, the AER has had regard to the requirements under clause 6.6.2(b) of NER and considered all submissions made on the STPIS pursuant to clause 6.10.1 of the NER. The AER’s decision on how the STPIS is to apply to the Victorian DNSPs can also be found in the determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy. Consistent with clause 2.1(d) of the STPIS, the AER's conclusions which form the basis of its constituent decision are set out below:

- The AER concludes that it will apply the SAIDI, SAIFI and MAIFI reliability parameters to the Victorian DNSPs, as set out in the STPIS. For transitional reasons the AER will apply the ESCV's definition of MAIFI discussed at section 15.7.8 of this chapter.

- Having regard to clause 6.6.2(b)(3)(i) and (vi) of the NER, the AER has concluded to apply the caps on revenue at risk as set out in table 15.25.

Table 15.25 AER conclusion on cap on revenue at risk (per cent)

	Cap on revenue at risk
CitiPower	±5
Powercor	±5
Jemena	±5
SP AusNet	±7
United Energy	±5

Source: AER analysis.

- Having regard to clause 6.6.2(b)(3)(vi) of the NER the AER concludes that it will apply the incentive rates at table 15.26 to the reliability and customer service parameters consistent with methodology set out at sections 3.2.2 and 5.3.2(a)(1) of the STPIS respectively.

Table 15.26 AER conclusion on incentive rates for SAIDI, SAIFI, MAIFI and the telephone answering parameter (per cent per unit)

	CitiPower	Jemena	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI	0.1731	–	–	–	–
SAIFI	9.2794	–	–	–	–
MAIFI	0.7424	–	–	–	–
Urban	–	–	–	–	–
SAIDI	0.0660	0.1299	0.0577	0.0444	0.1432
SAIFI	3.2702	7.8702	3.7592	3.0734	8.7494
MAIFI	0.2616	0.6296	0.3007	0.2459	0.6999
Short Rural	–	–	–	–	–
SAIDI	–	0.0054	0.0323	0.0350	0.0152
SAIFI	–	0.3497	2.5761	3.0267	0.9385
MAIFI	–	0.0280	0.2061	0.2421	0.0751
Long Rural	–	–	–	–	–
SAIDI	–	–	0.0280	0.0157	–
SAIFI	–	–	2.8058	1.3457	–
MAIFI	–	–	0.2245	0.1077	–
Telephone answering parameter	–0.040	–0.040	–0.040	–0.040	–0.040

Source: AER analysis.

- The AER will segment the reliability parameters by network type in accordance with the STPIS and apply the targets to these parameters as set out table 15.27. In establishing these targets the AER has had regard to the Victorian DNSPs' past performance in accordance with clause 6.6.2(b)(3)(iii) of the NER.

Table 15.27 AER conclusion—performance targets for SAIDI, SAIFI, MAIFI and the telephone answering parameter

	CitiPower	Jemena	Powercor	SP AusNet	United Energy
CBD	–	–	–	–	–
SAIDI (average minutes)	11.27	–	–	–	–
SAIFI (average interruptions)	0.186	–	–	–	–
MAIFI (average interruptions)	0.026	–	–	–	–
Urban	–	–	–	–	–
SAIDI (average minutes)	22.36	68.50	82.47	105.62	55.09
SAIFI (average interruptions)	0.450	1.127	1.263	1.520	0.899
MAIFI (average interruptions)	0.175	0.776	1.412	2.519	1.074
Short Rural	–	–	–	–	–
SAIDI (average minutes)	–	153.15	114.81	214.73	99.15
SAIFI (average interruptions)	–	2.588	1.565	2.697	1.742
MAIFI (average interruptions)	–	1.940	2.881	5.421	2.122
Long rural	–	–	–	–	–
SAIDI (average minutes)	–	–	233.76	267.10	–
SAIFI (average interruptions)	–	–	2.540	3.378	–
MAIFI (average interruptions)	–	–	6.535	8.996	–
Telephone answering parameter (per cent)	68.94	57.46	62.62	76.62	58.14

Source: AER analysis.

- The AER will close out the ESCV's S factor scheme by applying the methodology set out in section 15.7.12 of the draft decision. The adjustments to the building blocks are set out in Table 15.28.

Table 15.28 AER conclusion on the building blocks resulting from the ESCV S factor true-up ($, million)

	2011	2012	2013	2014	2015
CitiPower	0.15	–2.82	–3.32	–0.22	–6.89
Powercor	16.25	–7.57	–4.49	0.78	–28.71
Jemena	–2.17	0.27	0.74	0.76	0.40
SP AusNet	19.97	2.33	–5.11	0.83	–46.80
United Energy	–4.95	–18.81	–17.76	–18.15	–41.96

Source: AER analysis.

- Having regard to clauses 6.6.2(b)(2) and 6.6.2(b)(3)(ii), and consistent with section 6.1(a) of the STPIS, the AER concludes that it is bound to apply the existing Victorian GSL scheme under the Electricity Distribution Code and the Public Lighting Code, while this scheme remains in place.

- The AER concludes that it will allow the forecast GSL opex allowance pursuant to clause 6.5.6(a)(2) of the NER as set out in table 15.29.

Table 15.29 AER conclusion on annual total GSL payments ($, nominal)

DNSP	AER draft decision
CitiPower	15 470
Powercor	1 176 156
Jemena	18 892
SP AusNet	4 339 295
United Energy	266 810

Source: AER analysis.

- The MED threshold is to be calculated in accordance with section 3.3 of the STPIS and is to be based on the beta values set out in table 15.30.

Table 15.30 AER conclusion on MED threshold to be set X beta from the mean

MED thresholds	AER draft decision
CitiPower	2.5
Powercor	2.8
Jemena	2.5
SP AusNet	2.8
United Energy	2.5

Source: AER analysis.

16 Pass throughs

16.1 Introduction

The National Electricity Rules (NER) specifies certain pass through events which apply to all distribution network service providers (DNSPs).[1] This chapter sets out the AER's consideration of additional pass through events for the Victorian DNSPs during the forthcoming 2011–15 regulatory control period.

An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks appropriately and incurs additional costs, it would be expected to bear those costs. However, the NER recognises a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs.

16.2 Regulatory requirements

The NER specifies certain pass through events that are applicable to all distribution determinations. These are:

- a regulatory change event
- a service standard event
- a tax change event
- a terrorism event

The NER also provides that any additional event nominated in a distribution determination as a pass through event is a pass through event for that determination.[2]

The NER does not provide any specific criteria that the AER is to have regard to in assessing proposed additional pass through events. Accordingly, the AER has developed certain criteria for this purpose, and in developing these criteria has had regard to the National Electricity Objective (NEO) and the revenue and pricing principles contained in the National Electricity Law (NEL).

Chapter 6 of the NER sets out procedural requirements relating to the assessment of pass through applications during a regulatory control period.[3] These requirements apply equally to the pass through events set out in chapter 10 of the NER and the additional pass through events set out in a particular distribution determination. These provisions allow material increases or decreases in costs arising from pass through events to be passed through to network users.

When a pass through event occurs, the DNSP must inform the AER within 90 days of the event occurring.[4] It must provide a written statement providing details of the pass

1 See pass through events definition in Chapter 10 of the NER.
2 NER. ch. 10 (glossary)
3 NER cl. 6.6.1.
4 NER, cl 6.6.1(c) and (f).

through event.[5] The AER then assesses whether or not the event has occurred and determines, where necessary, the appropriate pass through amount. The AER also determines how that amount is to be recovered over the remainder of the regulatory control period. In doing this, the AER must consider certain factors set out in the NER.[6]

Chapter 6 of the NER was initially developed by the Ministerial Council on Energy (MCE) Standing Committee of Officials (SCO). As part of this process, SCO proposed the inclusion of certain pass through events in the NER.

The chapter 10 definition of pass through event (in addition to the four events listed above) also provides that '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).'

Clause 6.12.1(14) of the NER requires the AER to make a constituent decision on the additional pass through events that are to apply for the regulatory control period.

The AER has a broad discretion in respect of its decision on the additional pass through events that are to apply in a regulatory control period. It appears that neither the Chapter 10 definition of pass through event nor clause 6.12.1(14) limits the AER's discretion. Support for this position is also derived from clause 6.12.3 of the NER which sets out the extent of the AER's discretion in making distribution determinations. Clause 6.12.3(a) states that:

> Subject to this clause and other provisions of this chapter 6 explicitly negating or limiting the AER's discretion, the AER has a discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal.

While clause 6.12.3(f) limits the operation of clause 6.12.3 (a), the limit only applies to the AER's refusal to approve an amount or value. A pass through event cannot properly be described as an amount or a value.

The AER's discretion is, of course, subject to the NEO in section 7 of the NEL and the revenue and pricing principles in section 7A of the NEL (see discussion below).

16.3 Summary of Victorian DNSP regulatory proposals

Several of the Victorian DNSPs proposed identical (or very similar) pass through events as part of their regulatory proposals. A list of the proposed pass through events (and corresponding materiality thresholds) is outlined below.

16.3.1 CitiPower and Powercor

CitiPower and Powercor both proposed pass throughs events relating to broad changes in their regulatory obligations. Both DNSPs cited uncertainty as to whether these

5 Information that must be provided in relation to positive pass through events is contained in NER. cl. 6.1.6 (c) of the NER states that information that must be provided in relation to negative pass through events is contained in cl. 6.1.6 (f)of the NER.

6 NER, cl. 6.6.1(j).

events would be captured in the NER definition of 'regulatory change event', and therefore proposed that they be added as additional events for the purposes of the distribution determination. These events were:

- a transfer of non-pricing distribution regulatory arrangements to a national regulatory framework event [7]
- a change in safety regulations introduced by Energy Safe Victoria (ESV) event
- a changes in exposure limits event [8]
- a wind farm connection costs event (Powercor only).
- a recommendations arising from the Royal Commission into Victorian Bushfires event (Powercor only).[9]

CitiPower and Powercor also proposed the following pass through events, which generally related to new obligations arising from government policy responses to climate change, failure of a retailer, and new charges/fees:

- a financial failure of a retailer event
- a declared retailer of last resort event
- an Australian Energy Market Operator (AEMO) fees or charges event
- an emissions trading scheme (ETS) event
- a network extension for remote generation event (Powercor only)

Both CitiPower and Powercor justified the inclusion of these events on the basis of the pass though assessment criteria contained in the AER's New South Wales and Australian Capital Territory distribution determinations (for further discussion of these criteria see section 16.5 below). Further, the businesses submitted that the proposed events cannot be recovered through any other mechanism and are beyond the control of a DNSP. CitiPower and Powercor further justified these events by asserting that the associated costs cannot be forecast at the time of preparing the regulatory proposal and that such events would materially increase the costs of providing direct control services.

In addition, CitiPower and Powercor both proposed a 'general nominated pass through event' as previously adopted by the AER.

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[7] CitiPower, *Regulatory Proposal 2011 to 2015,* November 2009, p. 277; Powercor *Regulatory Proposal 2011 to 2015*, November 2009, pp.283–284.

[8] CitiPower, *Regulatory Proposal*, p.278–286; Powercor, *Regulatory Proposal*, pp. 285–292. Both businesses define this as introduced in the final version of the current Draft Radiation Protection Standard for Exposure Limits to Electric and Magnetic Fields 0Hz–3kHz, by the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA).

[9] CitiPower, *Regulatory Proposal*, p.278–286; Powercor, *Regulatory Proposal*, pp.285–292.

CitiPower and Powercor both proposed a materiality threshold of $5 million for all pass through events (negative and positive).[10]

16.3.2 Jemena Electricity Networks Victoria (Jemena)

Jemena's proposed pass through events mainly related to liability, climate change, insurance and financial failure of a retailer. Jemena's regulatory proposal did not discuss the relationship between nominated pass through events and the NER prescribed pass through events. Jemena proposed the following pass through events:

- a force majeure event
- a retailer of last resort event (such an event would have a cost impact on Jemena that is largely out of Jemena’s control)
- a financial failure of a retailer event (such an event would allow Jemena to pass through charges in excess of the credit support arrangements in place)
- an insurance event (probability of claims exceeding the insurance limit is low, but such an event cannot be adequately forecast)
- an insurer credit risk event (this risk is uncontrollable and unforeseeable and the event would likely have a material impact)
- an asbestos compensation event (this risk is uncontrollable and unforeseeable and the event would likely have a material impact)
- an ETS event (Jemena stated that there is still uncertainty as to the timing, form and extent of such a scheme, and that the associated costs are beyond Jemena's control).

Jemena was the only Victorian DNSP not to propose the 'general nominated pass through event' previously adopted by the AER. However, there are similarities between this event and the force majeure event proposed by Jemena.

Jemena proposed a materiality threshold of $1 million for all pass through events (both negative and positive).[11]

16.3.3 SP AusNet

SP AusNet's proposed pass through events related mostly to changed obligations, climate change and liability issues. SP AusNet's proposal did not discuss the relationship between nominated pass through events and NER prescribed pass through events, however, it did propose a materiality threshold for NER events in addition to those nominated in the regulatory proposal. SP AusNet proposed the following pass through events:

[10] CitiPower, *Regulatory Proposal*, p. 286; Powercor, *Regulatory Proposal*, pp. 294–295.
[11] Jemena, *Regulatory proposal 2011–2015*, November 2009, pp. 194–195.

- a forced load shedding event (despite the event being foreseeable, the cost and timing of such an event cannot be forecast, and the associated costs are uncontrollable. The event cannot be insured or self insured against)

- a legal liability above an insurance cap event (the event is not already insured against either externally or through self insurance and the event cannot be self-insured as the potential loss to the relevant DNSP is catastrophic)

- an s-factor payout event

- a carbon pollution reduction scheme event (such an event is not recovered elsewhere in the regulatory regime, and any cost impact is unclear at this point. The passing through of these costs would not undermine the incentive arrangements in the regulatory framework); and

- a premium feed in tariff event[12] (the costs of providing credits for premium feed in tariffs cannot be reasonably forecast).

In addition, SP AusNet proposed a general nominated pass through event.

SP AusNet proposed materiality thresholds of:

- $250 000 for all nominated pass through events and NER prescribed pass through events (negative and positive); and

- $1 million for general pass through events.[13]

16.3.4 United Energy

United Energy's proposed pass through events related mainly to changed regulatory obligations, financial failure of a retailer, tax changes and climate change impacts. United Energy proposed the following pass through events, and justified the inclusion of each event on the grounds that they meet pass though assessment criteria contained in the AER's New South Wales and Australian Capital Territory distribution determinations (for further discussion on these criteria, see section 16.5 below):

- an ETS event

- an introduction of new regulatory obligations for vegetation management around powerlines event

- a financial failure of a retailer event

- a retailer of last resort event

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12 SP AusNet, *Electricity Distribution Price Review, Regulatory Proposal*, November 2009, pp. 306–310. Note that the legal liability above insurance cap event proposed by SP AusNet is similar in definition to the 'insurance event' proposed by JEN, and that the CPRS event is similar in definition to the 'ETS event' proposed by the other Victorian DNSPs

13 SP AusNet, *Regulatory Proposal*, pp. 306–310

- a changes to corporate income tax event (stating that this event would not be covered by the 'tax change event' definition under the NER, as that definition explicitly excludes corporate income tax)
- a transfer of customer regulation to the national regulatory framework event (citing uncertainty as to whether this event would be captured in the NER definition of 'regulatory change event')
- a national broadband network event
- a climate change assumption being materially wrong event
- a force majeure event
- a changes to bushfire mitigation framework event.[14]

In addition, United Energy proposed a general nominated pass through event.

United Energy proposed materiality thresholds of:

- $200 000 (or administrative costs, whichever is lower) for specific nominated pass through events; and
- $3 million (or one per cent of annual average revenue, whichever is lower), for general nominated pass through events, and NER prescribed pass through events.[15]

16.4 Summary of submissions

The AER received two submissions on pass throughs events. These submissions were from the Energy Users Coalition of Victoria (EUCV) and the Consumer Action Law Centre (CALC).

16.4.1 CALC

The CALC submitted that the AER should:

> …implement a range of measures to ensure that distributors more closely follow benchmarks including monitoring capital works to ensure that deferrals are efficient, basing forecasting on general conditions instead of trying to cater for unpredictable or extreme events while allowing future pass throughs for events that cannot be forecast with some certainty, and ensuring that distributors become as efficient as possible. Consumers will get cheaper prices if benchmarks are more closely followed and if the industry becomes more efficient.[16]

[14] United Energy, *Regulatory proposal for Distribution Prices and Services, January 2011 – December 2015 November 2009*, pp. 253–265.

[15] UED, *Regulatory Proposal*, pp. 247–249.

[16] CALC, *Submission to the Review of initial Distribution Network Service Providers' Proposals for the 2011–2015 Regulatory Period*, 16 February , 2010, p. 16.

CALC recommended that the AER use pass through mechanisms to limit the uncertainty of forecasting. [17]

16.4.2 EUCV

In its submission, the EUCV stated:

> The EUCV is concerned that inherently allowing both an increase in the WACC (as the AER has done by increasing the market risk premium and taking a conservative view on equity beta in its recent WACC parameters review) and the ability to reduce risk by the inclusion of the increasing use of pass through provisions, will allow Victorian DNSPs an effective "double dip". [18]

The EUCV also noted that several of the nominated pass through events proposed by the Victorian DNSPs were explicitly considered, and excluded, by the Essential Services Commission of Victoria (ESCV) in previous regulatory determinations.[19] The EUCV further considers that Victorian DNSPs should be required to absorb the costs of any pass through events until the current capex and opex allowances are exceeded, and then new pass through events should be considered on their merits.[20]

16.4.3 Minister for Energy and Resources (Victoria)

The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria (the Minister), submitted that:

> To ensure that the Victorian electricity distributors are able to access funding available from the Australian government for the demonstration of smart grids, the AER should provide for the recovery of reasonable and efficient expenditure, in addition to that allowed for standard distribution and metering services, incurred by an electricity distributor in delivering smart grid demonstration programs.[21]

16.4.4 EUAA

The Energy Users Association of Australian (EUAA) stated that it did not support pass through arrangements, as they are asymmetric in favour of the DNSPs (and that intra period cost reductions are unlikely to be passed through to consumers). The EUAA noted:

> We would urge the AER to also consider this matter in the broader context of its regulation of network businesses, including the option of a Rule change that will lead to more balanced outcomes in future. In this context we note that the application of economic regulation to energy networks in Australia has been founded on the principle that the outcomes ought to mimic those found in competitive markets. With regard to pass through, this is clearly has limited application. In competitive markets, pass through only applies where costs are the result of factors outside the control of the business and then only

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17 CALC, *Submission to the AER*, p. 16.

18 EUCV, *response to AER Victorian electricity revenue reset on applications from CitiPower, Powercor, Jemena, SP AusNet, United Energy*, February 2010 pp.79–80.

19 EUCV, *Submission to the AER* pp.79–80.

20 EUCV, p. 80.

21 The Hon. Peter Batchelor, MP, Minister for Energy and Resources, *Submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–2015*, p. 8.

> if the business is in a position to be able to pass through these costs. In the case of regulated businesses, this needs to be recognised by the regulator with one eye to the risk of strategic behaviour by the regulated business.[22]

The EUAA noted specific concerns with the following proposed pass through events:

- vegetation management event (as this is normally calculated as opex)
- CPRS event (all Australian businesses will bear some costs for the CPRS, and allowing the DNSPs to pass through these costs minimises the incentive for them to reduce these costs)
- Insurer credit risk event (energy users should not have to pay for insurance costs as it is a responsibility of any business to insure themselves appropriately and efficiently)
- Asbestos compensation event (users should not have to pay for negligent behaviour on the part of the DNSPs).[23]

16.5 Issues and AER considerations

The AER notes that there are a number of relevant factors for consideration in the treatment of pass throughs. These include previous regulatory treatment of pass through events (both by the AER and other regulatory bodies). The AER has also considered a number of policy issues in developing its conceptual approach to the treatment of pass through events for the 2011-2015 regulatory control period. This section is structured as follows:

- the AER's previous approach to pass through events (in the New South Wales, Australian Capital Territory, South Australia and Queensland distribution determinations)
- interaction with NER prescribed pass through events (the implications arising from the pass through events already codified in the NER on how the AER should exercise its discretion in accepting additional events in distribution determinations), magnitude, controllability, foreseeability and probability (how each of these factors impacts on the appropriate regulatory treatment of that event)
- materiality (the appropriate threshold to apply to approved pass through events for the 2011-2015 regulatory control period)
- the interaction of pass throughs and the form of control.

16.5.1 Previous AER approach to pass through events

In previous regulatory determinations, the AER has consistently approved two types of additional pass through events:

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22 EUAA, AER *Review of Victorian electricity distribution prices and distributors' proposals for the period 2011–2015*, pp. 15–16.

23 EUAA, AER *Review of Victorian electricity distribution prices and distributors' proposals for the period 2011–2015*, pp. 15–16.

- a 'general' nominated pass through event
- additional 'specific' nominated pass through events.[24]

General nominated pass through event

In the AER's most recent distribution determinations, the South Australia and Queensland distribution determinations, the AER applied of a general nominated pass through event.[25]

An event is considered to be a general nominated pass through event where it meets the following criteria:

- an uncontrollable and unexpected event occurs during the forthcoming 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.[26]

Specific nominated pass through events

For the South Australia and Queensland distribution determinations, the AER assessed nominated pass through events proposed by the DNSPs against the following criteria:

- whether the event is already captured by the prescribed NER event definitions
- whether the event is clearly identified

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24 AER, Queensland distribution determination 2010–11 to 2014–15, Final decision, May 2010, pp. 223–242

25 ibid.
The initial definition of a 'general nominated pass through event' was developed in the New South Wales and Australian Capital Territory distribution determination process. That definition was as follows:
1. An uncontrollable and unforeseeable event that falls outside of the normal operations of the business, such that prudent operational risk management could not have prevented or mitigated the effect of the event, occurs during the forthcoming regulatory control period.
2. The change in costs of providing distribution services as a result of the event is material, and is likely to significantly affect the DNSP’s ability to achieve the operating expenditure objectives and/or the capital expenditure objectives (as defined in the transitional chapter 6 rules) during the forthcoming regulatory control period.

An event will be considered unforeseeable for the purposes of this definition if, at the time the AER makes its distribution determination, 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 forthcoming regulatory control period.
This determination was appealed. As part of that appeal process, the references to *'outside of the normal operations of the business*' were removed. The definition of a general nominated pass through event was then further updated for the South Australia and Queensland distribution determinations.

26 For the purposes of this definition, an event is material if it exceeds one percent of the smoothed forecast revenue in each of the years of the regulatory control period.

- whether 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 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[27]

- whether the event is not already insured against (either external or self insured)

- whether the event cannot be self-insured because a self insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic

- whether the party who is in the best position to manage the risk is bearing the risk

- whether the passing through of the costs associated with the event would undermine the incentive arrangements within the regulatory regime.[28]

The materiality threshold for these events is the administrative costs of assessing such an application for a pass through event.[29]

16.5.2 Interaction with the NER prescribed pass through events

While the NER permits the AER to include additional pass through events in its distribution determinations, the AER does not consider that it would be an appropriate exercise of its discretion to include additional events that already fall within one of the specified pass through events in chapter 10 of the NER.

The AER notes that one justification advanced by the DNSPs for several of the proposed pass through events is the uncertainty of whether they qualify as NER prescribed pass through events. In particular, there are a number of possible new or changed regulatory obligations which some DNSPs suggest may not meet the NER definition of a 'regulatory change event'. Further, United Energy (as part of its argument in support of a national electricity customer framework event), stated that:

> …a regulatory change event is limited to changes in a regulatory obligation or requirement and does not encompass the removal or imposition of a new regulatory obligation or requirement (consider, by way of contrast, the definition of a tax change event). Accordingly, to meet the AER's requirement that a nominated pass through event cannot already be captured by the defined event definitions, UED proposes to deal with this event in a

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27 In the New South Wales and Australian Capital Territory distribution determinations, this criterion was: despite the event being foreseeable (meaning more likely than not to occur in the forthcoming regulatory period), 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 This is the only difference between the specific nominated pass-through event criteria between the New South Wales and Australian Capital Territory distribution determinations and the South Australia and Queensland distribution determinations.

28 *South Australian Distribution determination 2010–2015, final decision*, p. 397.

29 *New South Wales, Distribution Determination,2009–201, Final decision,* p. 281.

> manner which corresponds with the way in which Integral Energy dealt with the emissions trading scheme event[30]

The AER agrees with United Energy's assessment that a 'regulatory change event' is restricted to changes in existing regulatory obligations for the reasons stated by United Energy. However, the AER also notes that the NER definition of 'service standard event' is, relevantly, 'a legislative or administrative act or decision' that has the effect of:

- substantially varying, during the course of a regulatory control period, the manner in which a DNSP is required to provide a direct control service, or
- altering, during the course of a regulatory control period, the nature or scope of the direct control services provided by the service provider.[31]

Accordingly, the NER definition of 'service standard event' appears to capture the removal of existing, or imposition of new, regulatory obligations beyond those obligations that might ordinarily be considered a 'service standard'. (Similarly, the NER definition of 'regulatory change event' includes the criteria that the change in the regulatory obligation *'substantially affects the manner'* in which the DNSP provides direct control services).

Notwithstanding the definition of regulatory change event being limited to changes to existing regulatory obligations or requirements, the service standard event could capture the pass through of material cost increases or decreases relating to the imposition of new regulatory obligations (subject to the additional criteria for a service standard event being met).

It is likely that a proper assessment of whether a new regulatory obligation meets these criteria cannot be made until the event has occurred and associated costs can be quantified. This is because the timing and cost of such an event cannot be known until that event occurs. However, DNSPs have the certainty that if a new, changed or removed regulatory obligation meets these criteria than the pass through will be accepted.

On the other hand, there may be new regulatory obligations that arise during the regulatory control period that do not meet the criteria for a service standard event. For example, a new regulatory obligation may not 'substantially' affect the manner in which the DNSP provides direct control services. Ultimately, if the Victorian DNSPs consider that the defined pass through events in Chapter 10 of the NER are in some way problematic, this should be raised with the rule making body, the AEMC.

This approach is intended to permit DNSPs to pass through legitimate, genuinely uncontrollable costs in a manner that does not conflict with the pass through events already nominated by the NER.

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30 United Energy, *Regulatory Proposal*, p. 250.

31 In addition to materially increasing or decreasing the cost to a DNSP of providing direct control services.

Accordingly, the AER does not accept the following events on the basis that they are events relating to possible new, changed or removed regulatory obligations that are either already within the scope of the 'regulatory change event' or 'service standard event.' As such, it would be unnecessary or inappropriate to accept the following events: [32]

- a transfer of non-pricing distribution regulatory arrangements to a national regulatory framework event (proposed by CitiPower and Powercor)
- a change in safety regulations introduced by the ESV event (proposed by CitiPower and Powercor)
- a changes in exposure limits event (proposed by CitiPower and Powercor)
- a recommendations arising from the Royal Commission into Victorian Bushfires event (proposed by Powercor)
- an ETS event (proposed by CitiPower, Powercor, Jemena and United Energy) and a CPRS event (proposed by SP AusNet)
- a transfer of customer regulation to national regulatory framework event (proposed by United Energy)
- an introduction of new regulatory obligations for vegetation management around powerlines event (proposed by United Energy)
- a changes to bushfire mitigation framework event (proposed by United Energy)
- a national broadband network event (proposed by United Energy)
- a change in corporate income tax event (proposed by United Energy)
- an AEMO fees and changes event (proposed by CitiPower and Powercor)

Finally, the AER also considers that it would not be an appropriate exercise of its discretion to include additional events that conflict with, or have the effect of undermining, the specified pass through events in Chapter 10 of the NER.

An example is United Energy's proposal for a 'change in corporate income tax event'. United Energy has submitted that changes in corporate income tax would not meet the definition of a 'tax change event' in the NER. The AER agrees with United Energy's assessment as the NER tax change event is restricted to changes in a 'relevant tax'; this explicitly excludes 'income tax'. As the NER explicitly excludes corporate income tax changes from the definition of a tax change event, the AER considers it would be inappropriate to accept the additional pass through event proposed by United Energy.

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[32] It would be inappropriate to accetp event relating to possible new, changed or removed regulatory obligations that directly conflict with the definitions of 'regulatory change event' or 'service standard event.'

It would, however, be open to United Energy to approach the AEMC to seek a relevant rule change.

The EUAA's submission made comments in relation to a vegetation management event and a CPRS event. It claimed that the vegetation management event should be rejected on the basis that vegetation management is already recovered through opex. The AER recognises that vegetation management allowances are already permitted through the forecast opex for the DNSPs, and envisages that any cost pass through in relation to vegetation management would be costs incurred through a new regulatory obligation (imposed on the DNSP), rather than business as usual vegetation management. In response to the EUAA's argument that the CPRS event should be rejected on the basis that it will reduce incentives for the DNSPs to mitigate costs associated with the CPRS, the AER considers that these costs will likely be unable to be mitigated, as they would likely be incurred through administrative costs and fees (that is, set charges which cannot be reduced by the DNSP).

16.5.3 Relevant considerations

In considering pass through events proposed by the DNSPs, the AER has had regard to the following considerations discussed below.

Foreseeability vs. probability

In the New South Wales and Australian Capital Territory distribution determinations, the AER considered that 'foreseeability' was a relevant consideration in assessing whether or not to accept a specific nominated pass through event. For this purpose, the AER stated that it considered an event was foreseeable if it was 'being more likely to occur than not' in the forthcoming regulatory control period. In the South Australia and Queensland distribution determinations, the AER substituted this foreseeability criterion with a requirement that the event in question had to be 'highly likely to occur' in the forthcoming regulatory control period.[33] In essence, both of these criteria were probability-based criteria, but with a different probability threshold applied in the determinations.

Probability is a relevant consideration for the recovery of costs in other aspects of the regulatory regime, such as self insurance. Where it is determined that it is appropriate to provide a self insurance allowance (as part of the opex allowance) to compensate for a certain risk, the probability of the relevant event occurring is typically used in quantifying an appropriate self insurance premium. The AER notes that probability is not a relevant consideration for most types of pass through events (for example, a changed obligation, which should be recovered regardless of how likely it is to occur). However, certain events which have a very high magnitude (for example, an earthquake) but are of a very low probability, should be treated as pass through events. For these reasons, the AER considers that a probability-based criterion is no longer relevant to the assessment of pass-through events.

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[33] *South Australia draft distribution determination, draft decision,* p. 397 It was considered that the term reasonable foreseeability might engender confusion because the legal term can sometimes require a 'possibility-based' test rather than the probability test envisaged by the AER.

The AER does consider that foreseeability is a relevant consideration, but with a different meaning to that adopted in the New South Wales and Australian Capital Territory distribution determinations.

The opex and capex criteria in the NER only permit costs for existing obligations on the DNSPs. Where an obligation has not come into force at the time of a distribution determination, no allowances are provided for the DNSPs to adhere to that obligation.[34] The AER, however, notes the overarching requirement in the NEL to provide DNSPs with a reasonable opportunity to recover at least their efficient costs.[35] Implicit in this requirement is allowing DNSPs to recover for risks that are not compensated elsewhere in the regulatory regime. For this reason, the AER considers that a pass through event should be foreseeable in that the *nature* of the event is foreseeable. That is, even if the specific event is known (the timing and costs of the event are foreseeable but the costs cannot be quantified), where costs associated with the event cannot be recovered through any other mechanism, it should be treated as a pass through event.

Magnitude

The AER has considered previously that events that are of a high magnitude (and cannot be recovered through other mechanisms, or are self insured) should be considered as pass through events.[36] Events that occur that are likely to have a large or catastrophic impact are not appropriately treated as self insurance categories.

Controllability

The AER has previously considered that the pass through event in question must be uncontrollable (in terms of cost, and timing).[37] Where the cost impact of an event can be mitigated or at least partially mitigated (even if the occurrence of the event cannot) it is more appropriately treated as a self insurance category. This is because, as the insuring party is also the party who is insured (and must bear the cost of any event occurring), it will be incentivised to either prevent that event from occurring, or minimise the cost impact of that event.

In particular, where an ex ante allowance is provided via a self-insurance allowance which is based on the expected probability and cost outcome of the event, the DNSP will have a strong incentive to mitigate the timing and cost of the event. The AER can only approve costs that are incurred efficiently to be passed through to consumers. However, due to the information asymmetry that exists between the regulator and the service provider in undertaking an ex post assessment (that is, after the event has occurred and expenditure has been incurred), it can be difficult for the AER to identify and remove any inefficient costs. Accordingly, costs that have a controllable component are better included as part of the ex ante framework, and a self insurance allowance provided at the time of the distribution determination.

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[34] The opex and capex criteria under cll. 6.5.6 and 6.5.7 of the NER only allow for costs associated with existing obligations.
[35] As mandated by the Revenue and Pricing Principles contained in s. 7A of the NEL.
[36] *New South Wales, Distribution determination 2009–2014, final decision*, p. 296.
[37] ibid., p. 279.

Interaction between foreseeability, probability, magnitude and controllability

The AER notes that there is a relationship between self insurance and pass throughs within the regulatory regime. Events that may not be appropriately treated as pass throughs can be included as self insurance, or vice versa.

The relationship between the above factors and the appropriate regulatory treatment of each one is summarised in table 16.1 below. The table describes the interplay between foreseeability, magnitude, controllability and probability impact and how the AER will classify an event in the regulatory control period.

Table 16.1 Consideration of factors in treatment of events

	Pass throughs	Self insurance
Foreseeability	Where an event is foreseen (in that an event of its nature could occur but is not known at the time) and the cost and timing are not known, more likely treated as a pass through event.	Foreseeability also relevant to self insurance (as the risks needs to be identifiable)
Probability	Probability is not a relevant consideration, however low probability events with a very high consequence are appropriately treated as pass throughs.	Where probability can be quantified (and used to calculate a self insurance premium), more likely to be treated as a self insurance category.
Magnitude	Where an event has high magnitude, more likely to be treated as pass through event.	Where an event has a low magnitude, more likely to be treated as a self insurance category.
Controllability	Where the event is beyond the control of the DNSP, it is more likely to be treated as a pass through event.	Where the event (or its impact) can be in part controlled or mitigated by the DNSP, more likely treated as a self insurance event.

Source: AER analysis

Whether or not an event should be treated as a pass through or a self insurance category depends on the relationship of the above factors. A tension may exist between these factors. For example, an event could be of a high magnitude, which ordinarily would mean that it is best categorised as a pass through event. However, due to its controllable nature, it is probably better considered as self insurance.

16.5.4 Materiality

The AER included the following cost-based materiality thresholds for the additional pass through events it approved in previous distribution determinations:

- specific nominated pass through events—the administrative costs of assessing such an application for a pass through event; and

- general nominated pass through events—one percent of the smoothed forecast revenue in each of the years of the regulatory control period.[38]

However, the AER notes that this materiality threshold is a separate requirement to the materiality threshold contained in Chapter 6 of the NER. Briefly, clause 6.6.1 provides that upon the occurrence of a pass through event (which is described as either a 'positive change event' or a 'negative change event'), a DNSP may seek the approval of the AER to pass through the relevant pass through amount to users. The definitions of a positive change event and a negative change event in Chapter 10 of the NER each contain a materiality threshold. For example, a positive change event is defined as:

> For a *distribution network service provider*, a *pass through event* that materially increases the costs of providing *direct control services*. [39]

Apart from any materiality threshold for an additional pass through event determined by the AER, the event in question (when it occurs) must still *'materially'* increase or decrease the costs of providing direct control services. The word 'material' or 'materially' is not defined in the NER and must therefore be interpreted in accordance with its plain and *ordinary meaning.*

The AER considers that the materiality threshold required for specific nominated events in previous distribution determinations − administrative costs of assessing a pass through application − would be unlikely to meet the ordinary meaning of the word materially. Accordingly, an event which only meets the administrative costs materiality threshold may not ultimately qualify as a 'positive change event' under the NER. This potentially creates a situation where the event meets the relevant materiality threshold of the additional pass through event in the distribution determination, but cannot, upon its occurrence, be passed through to customers as it does not qualify as a positive change event (as it does not '*materially'* increase costs).

The AER considers it appropriate to reduce any potential for such a situation to occur. Accordingly, the AER will align the materiality threshold contained for additional pass through events that meets the ordinary meaning of the word '*materially*'.

As set out in section 16.3, the Victorian DNSPs have proposed the following materiality thresholds:

- CitiPower—$5 million for all pass through events (negative and positive)[40]
- Jemena—$1 million for all pass through events (negative and positive)[41]
- Powercor—$5 million for all pass through events (negative and positive)[42]

38 ibid., pp. 267–281.
39 NER, chapter 10.
40 CitiPower, *Regulatory Proposal*, p. 286.
41 Jemena, *Regulatory Proposal*, pp. 194–195.
42 Powercor, *Regulatory Proposal*, pp. 294–295.

- SP AusNet—$250 000 for specific nominated pass through events and NER prescribed pass through events (negative and positive) and $1 million for general pass through events[43]

- United Energy—$200 000 or administrative costs (whichever is lower) for specific nominated pass through events, and $3 million or one per cent of annual average revenue (whichever is lower), for general nominated pass through events and NER prescribed pass through events.[44]

The AER will not retain the administrative costs threshold applied in previous distribution determinations. The AER notes that the purpose of a materiality threshold is to reduce the administrative burden of excessive applications for pass through events, while still including events which may materially affect the business. To achieve this, the AER considers it reasonable that an event should have an impact of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

The AER further notes it is appropriate to apply the same materiality threshold to all of the Victorian DNSPs, for consistency. Therefore, the materiality threshold for the Victorian DNSPs will be a percentage of revenue. This is consistent with the AER's approach to pass throughs in transmission regulation. The AER notes that the revenue requirement for the Victorian DNSPs in 2010 ranges between $180 million and $424 million.[45] The AER considers that a threshold of one per cent of the smoothed forecast revenue is not substantially different from the $5 million materiality threshold proposed by CitiPower and Powercor, or the $1 million materiality threshold proposed by Jemena.

The AER also notes that a one percent threshold has been applied to the general nominated pass through event in previous distribution determinations. In addition, for transmission cost pass throughs, the materiality threshold is prescribed under the NER, and is set at one percent of the TNSP's maximum allowed revenue (MAR). The AER considers that without a good reason for differences, consistency between transmission and distribution regulation is desirable.

Accordingly, the AER considers that the appropriate materiality threshold for all pass through events for the Victorian DNSPs is one per cent of the smoothed forecast revenue in each of the years of the regulatory control period.

16.5.5 Interaction with the form of control mechanism

The AER considers that there are certain costs which should be compensated for through the regulatory regime, although not treated as pass through events. Costs of this nature would not likely meet the materiality threshold under the pass through arrangements; however, the AER considers that these costs should be recovered regardless of their scope or magnitude. For this reason the AER has decided to reject the following event:

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43 SP AusNet, *Regulatory Proposal,* pp. 306–310.
44 United Energy, *Regulatory Proposal,* pp. 247–249.
45 *ESCV, Electricity Distribution Price Review, 2006–2010, Final decision,* Volume 1, pp. 459–461.

- premium feed in tariffs (as proposed by SP AusNet).[46] The AER notes that the AEMC is currently considering a rule change proposal which will allow DNSPs to include, in their form of control formula, a component to recover costs associated with premium feed in tariffs.[47] This process is currently open for stakeholder consultation closed recently (21 May 2010). Subject to this process being finalised, the AER will provide for recovery of these costs in its final determination (to be published later in 2010) as part of the Victorian DNSPs' form of control formulas. Therefore, the AER rejects this event as a pass through event.

16.5.6 AER's conceptual approach to pass throughs for Victorian DNSPs

The AER will assess all other pass through events against the following assessment criteria which build on the previous assessment criteria from previous AER distribution determinations. These assessment criteria are based on the assessment criteria applied in the New South Wales and Australian Capital Territory distribution determinations. However, several inclusions have been made to reflect the AER's treatment of pass throughs for TNSPs, as reflected in its transmission guideline on pass throughs.[48] The AER considers that consistency with regulation of transmission networks is an important consideration.

The proposed nominated pass through event must meet all the criteria to be accepted for the purposes of this draft determination.

The criteria are:

- the event is not already provided for:
  - in the defined event definitions in the NER (and does not conflict or undermine the events defined in the NER)
  - through the opex allowance (e.g. the insurance or self insurance components)
  - through the WACC (events which affect the market generally and not just the provider are systematic risk and already compensated through the WACC), or
  - through any other mechanism or allowance
- the event is foreseeable—in that the nature or type of event can be clearly identified
- the event is uncontrollable—in that a prudent service provider through its actions could not have reasonably prevented the event from occurring or substantially mitigated the cost impact of the event

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[46] This is recovered through the transmission form of control formula, see chapter 4 for discussion.

[47] AEMC, *National Electricity Amendment (Payment under Feed In Schemes and Climate Change Funds).* See www.aemc.gov.au for further information.

[48] This transmission guideline on pass throughs and re-openers can be found on the AER's website at www.aer.gov.au.

- the event cannot be self-insured because a self insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic[49]

- the party who is in the best position to manage the risk is bearing the risk

- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

The AER considers that its conceptual approach to the treatment of pass through events results in outcomes that are consistent with the NEO contained in section 7 of the NEL, which states:

> 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.

The AER considers that its treatment of pass through events will promote the long terms interest of consumers by ensuring that prices are reflective of network operating costs, and that, to the extent that extra costs are passed through in the regulatory control period, those costs are beyond the control of the DNSP. The reliability and security of electricity supply on the network is also ensured by allowing costs incurred through the inclusion of the 'natural disaster event'. For example, costs associated with natural disaster events, if not passed through, could potentially undermine the financial viability of the DNSP and threaten the security of supply on the network.

The AER also considers that this approach is consistent with the revenue and pricing principles (RRP) contained in section 7A of the NEL. The principles which are particularly relevant to the treatment of pass through events are as follows:

> (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 -

[49] Note the discussion in section 16.5.4 above on controllability. The AER considers that events that are of a very high magnitude, (and a self insurance allowance would not adequately compensate the DNSPs for costs incurred if the event occurs) should be treated as pass throughs

(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.

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

Sections 7A (2)(a) and (b) of the NEL provide that DNSPs should be able to recover at least the efficient costs the operator incurs in providing direct control network services and complying with regulatory obligations or requirements. The AER notes that costs that are uncontrollable (or controllable but of a high magnitude) are only passed through where they are not recoverable elsewhere in the regulatory regime and to do otherwise would allow DNSPs to recover above the efficient costs of delivering direct control services. The AER acknowledges the need for DNSPs to recover the efficient costs associated with meeting regulatory obligations or requirements that are not recovered elsewhere. The AER considers that the appropriate mechanism for the recovery of these costs is through the pass through events contained in the NER. This will necessarily align the policy intent of the NEL with the provisions of the NER. However, the AER's role is not to broaden the scope of those pass through provisions, and hence has the AER excluded proposed events that seek to broaden the scope of NER prescribed events as nominated pass through events (refer to section 16.5.2).

In relation to section 7A(3) of the NEL, the AER notes that DNSPs should be provided with incentives to efficiently provide network services. To promote this objective, the AER has included in its pass through event assessment criteria, the requirement that pass through events are beyond the control of the DNSPs. The AER considers that restricting pass throughs to events that are beyond the control of the DNSPs will not affect the incentives for the DNSP to mitigate (and reduce the cost impact of) these events given they are beyond the DNSP's control. In contrast, allowing the costs associated with events that are within the control of the DNSPs as a pass through would undermine the incentives of the regulatory regime. Accordingly by restricting pass through events that are beyond the control of the DNSPs, the AER is ensuring that costs which can be mitigated by the DNSP are not being passed through to consumers. This is also consistent with the AER's view that the risk associated with an event lies with the party who is best placed to manage that risk.

General pass through event

In developing the definition of the general pass through event, the AER acknowledged that certain events are uncontrollable and unforeseeable. However, the AER for this draft decision has reviewed its interpretation of 'unforeseeable'. The AER has previously (in the New South Wales and Australian Capital Territory distribution determinations) considered that an event must be 'more likely to occur than not' in the forthcoming regulatory control period to be considered as a pass through event. In the AER's Queensland and South Australia distribution determination final decisions, the foreseeability criteria was amended such that the event had to be highly likely to occur in the forthcoming regulatory control period. However, the AER has reviewed this criterion and considers that foreseeability should be considered in terms of whether the event can be tightly defined in advance rather than the notion of foreseeability being connected to the probability of the event occurring in a particular period of time (refer to section 1.5.3).

The AER notes that the possibility of high magnitude events occurring places a level of risk on DNSPs. This level of risk is such that, should the event occur, the associated costs of the event could threaten the financial viability of the DNSP. This is clearly an undesirable outcome, and can, in part, be mitigated by regulatory certainty provided in the relevant decision or determination. In its final decision for the New South Wales distribution determination, the AER stated:

> The AER recognises the possibility of events occurring during a regulatory control period that are uncontrollable, unforeseen, and have a material impact on costs. Examples of such an event include a major natural disaster such as a bushfire or 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, its occurrence is unforeseen in that the event is not expected to occur during the forthcoming regulatory control period.
>
> If an unforeseeable and uncontrollable event would have a material impact on a NSW 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 transitional Chapter 6 rules, 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 waiting until the forthcoming regulatory control period. [50]

The AER also notes its pass through guideline which was released before the Chapter 6A rules (for transmission network service providers (TNSPs)) were developed. The guideline relevantly provided that all pass through events should be tightly defined in advance, to minimise regulatory discretion during the regulatory control period.[51] This aim is effectively being achieved through the removal of the general pass through event, and its replacement with the natural disaster event. This event is defined in advance and will minimise any decision making discretion retained during the 2011-2015 regulatory control period.

The AER's pass through guideline also noted that there is the potential for costs incurred during the regulatory control period to be so large that the allowances provided by the AER would not cover efficient operating costs of the TNSP. The guideline noted:

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50 *New South Wales Distribution determination 2009–2014*, Final decision, p. 278.

51 See AER's Transmission guideline of the treatment of pass through. This instrument was developed for the economic regulation of transmission networks in anticipation of the chapter 6A of the NER. However, the principles contained therein can be applied to the economic regulation of networks more generally. A copy of this guideline can be found on the AER's website at www.aer.gov.au.

> These cost differences can be endogenous, that is, due to circumstances within the TNSP's control, and exogenous, that is, due to the occurrence of unforecast events predominantly outside the TNSP's control.[52]

The guideline provided three general issues to be assessed in developing a cost pass through mechanism for TNSPs. These were:

- the separation of controllable and uncontrollable costs. A regulator must seek to separate out and clearly define the uncontrollable event that will be the subject of the pass-through mechanism, which is difficult given that TNSPs are able to at least partly mitigate the likelihood and impact of most cost events. A regulator's judgment on whether pass-through risks can be clearly defined before they occur is an important determinant of the type of regime for pass throughs.

- incentives to manage the controllable part of risks faced by the TNSP is required to avoid the moral hazard problem.[53] An incentive to manage risks occurs where the TNSP is responsible for controllable costs, either through defining the pass through on an ex-ante basis, and/or making TNSPs liable for some of the cost of exogenous events.

- the regulatory regime should seek to maximise certainty for the operation and outcomes of a pass-through mechanism. TNSPs should be able to predict how the regime will be implemented by the regulator in advance.[54]

The AER notes particularly the first point, which states that:

> A regulator's judgment on whether pass-through risks can be clearly defined before the beginning of a revenue cap is an important determinant of the type of regime that a regulator will implement.

This is an important issue relating to foreseeability. The AER considers that a particular type of event should be foreseeable such that it can be clearly identified and defined at the time of the relevant determination. This provides regulatory certainty for the service provider, by reducing the discretion of the regulator within the regulatory period. Although arguably some costs, particularly those relating to exogenous events, cannot be accurately predicted or forecast, the types of events that would trigger these costs can be predicted and hence defined in advance.

The AER notes that general pass through provisions have also been considered by SCO in the development of the Chapter 6 NER provisions for the economic regulation of distribution networks. In developing Chapter 6 of the NER, SCO noted that the provisions for the treatment of pass throughs for DNSPs should be broadly similar to those for TNSPs.[55] SCO noted the revenue cap reopener provision in clause 6A.7.1 of the NER. This permits TNSPs to reopen revenue caps and pass through to consumers

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52 AER, *Transmission guideline on treatment of pass throughs*, p. 10.

53 ibid., p. 12. The moral hazard problem arises when a NSP is not provided with the incentive to minimise the costs or likelihood of occurrence of exogenous events (for example through spending on insurance, safety or security measures).

54 ibid., p. 12.

55 Ministerial Council on Energy (MCE) Standing Committee of Officials, *Explanatory material - revenue and pricing principles*, p. 13.

the costs of an event which is beyond the reasonable control of the provider.[56] This reopener is subject to the following threshold requirements:

- a materiality threshold, being five per cent of the regulatory asset base (RAB)
- that the capex required to treat such an event exceeds the total allowed capex for that regulatory period.[57]

SCO considered that the inclusion of such a 'general reopener' provision was not necessary in Chapter 6 for DNSPs. This is because high magnitude events that would likely trigger the reopener provision for TNSPs would be unlikely to occur on a distribution network. As previously noted, the NER confers upon the AER considerable discretion to develop its own criteria for approving or rejecting nominated pass through events in each distribution determination. The AER notes that its general pass through provision in recent distribution determinations is somewhat analogous to the capex reopener provision (for TNSPs) in the NER. However, the AER has not mandated that DNSPs exhaust their capex and opex allowance before passing through costs from a nominated event. Whilst this is required by Chapter 6A for transmission reopeners (and suggested by the EUCV) it this would undermine, or potentially ignore, efficiency gains made throughout the regulatory control period that had been accrued before the pass through event occurred (e.g. efficient gains realised under the EBSS).

The issue of a general cost pass through provision was considered by the ESCV in its 2006–10 *Electricity Distribution Price Review* (EDPR), as noted by the EUCV and EUAA in their submissions.[58] The ESCV rejected a proposal by CitiPower and Powercor to include a general pass through of costs for the 2006-10 regulatory control period, stating that this would be inconsistent with the principle of allowing cost pass throughs only for clearly specified events. The ESCV considered that the incentive effects of the regulatory framework would be reduced if general cost pass throughs were permitted.[59] The ESCV also argued that it would be it difficult to accurately assess the scope of such events should they occur. In particular, the ESCV also noted the problem of information asymmetry between the DNSP and the regulator, stating that:

> Information asymmetry would make it extremely difficult for the Commission to identify where exogenous changes had resulted in a cost decrease for a distributor. Intrusive and quite heavy handed regulation and monitoring would need to be introduced to identify any cost decreases and ensure that the full effects of these were passed through to customers. This would impose large resource costs on the distributors and on the Commission and would be akin to regulating via revenue cap. It is notable that the distributors, including CitiPower and Powercor, have continually raised

56 NER, cl. 6A.7.1 (a). Also note the requirement that the event could not have been foreseen at the time of the revenue determination.

57 NER, cl. 6A.7.1 (4).

58 EUCV, *Submission to the AER,* pp.79–80; ESCV, *EDPR 2006–10,* Volume 1, October 2006, pp 489–90; EUAA, *Submission to the AER,* pp. 15–16.

59 ESCV, *EDPR, 2006–10, Vol. 1, October 2006, pp. 489–490*

> concerns about the use of heavy handed regulation throughout this price review.[60]

Based on these factors, the AER no longer considers it appropriate to include a general nominated pass through event for DNSPs as the general pass through event does not meet the following assessment criteria:

- the passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime (refer discussion of the ESCV's concerns with information asymmetry, and SCO policy positions discussed above)

- the event is foreseeable in that the nature or type of event can be clearly identified (see discussion of AER's transmission guideline above).

The AER considers that events of this nature can be captured through the inclusion of a nominated pass through event, that is, the 'natural disaster' pass through event (defined below). The AER's policy on these types of events has evolved as a result of its consideration of the ESCV's previous treatment of such general pass through events for the Victorian DNSPs. Whilst the AER acknowledges that it is not bound to follow the ESCV's approach to pass throughs, it wishes to maintain the incentives put in place by the previous regulator to ensure a smooth transition to the new regulatory framework. The AER considers that such an approach will capture all major uncontrollable costs of a high magnitude (which was the intent of the general nominated pass through event), whilst creating further regulatory certainty for the Victorian DNSPs. The AER considers that the removal of the general pass through event mitigates some of the concerns raised by the EUAA in its submission on information asymmetry and the lack of incentives on the DNSPs to pass reduced costs on to consumers.

Accordingly, the AER has included the following additional events for each Victorian DNSP:

A natural disaster event:

> Any major fire, flood, earthquake, or other natural disaster beyond the control of the DNSP (but excluding those events for which external insurance or self insurance has been included within the DNSP’s forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to the DNSP of providing direct control services.
>
> For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

Specific nominated events

The AER rejects the following specific nominated pass through events on the basis that they cannot be clearly identified and defined in advance, it undermines the

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[60] ibid.

incentive properties in the regime, and that it is not uncontrollable and not of a high magnitude.

- A climate change assumption being materially wrong (proposed by United Energy)

The AER notes CALC's assertions that the pass through mechanism should not be used to compensate for inaccuracies in forecasts. The AER agrees with CALC and notes that inaccuracies in forecasts should be symmetric over time and the regulatory regime minimises forecast error to the extent that costs are reset every five years. However, the AER notes that the ex ante framework provides that businesses should undertake forecasting at the beginning of the regulatory control period. The AER also notes that the price cap form of control provides incentives for DNSPs to realise efficiencies (the DNSP is incentivised to reduce its costs). These incentives are further enhanced by the operation of the EBSS. Allowing DNSPs to recover costs associated with poor forecasting dilutes these incentives. Further, allowing inaccurate forecasts to be treated as pass throughs effectively adds an ex-post assessment to the regulatory regime, which is not provided for in the NER. The AER notes that some costs cannot be forecast with any certainty due to their uncontrollable nature (e.g. licence fees imposed on the DNSP). However, these costs are not treated as pass throughs, but are recovered as they are incurred through the form of control formula, in each year of the regulatory control period.

The AER rejects the following events on the basis that the passing through of the costs associated with the event would undermine the incentive arrangements within the regulatory regime. The AER also notes that the cost impact of such an event is not entirely beyond the control of the DNSP.

- a forced load shedding event.

The AER considers that this event should not be compensated for. Although the AER notes that potential losses can occur through forced load shedding, it also notes that any losses can be mitigated through the DNSPs actions. To allow costs associated with this event to be passed through to consumers, the DNSPs incentives to return the network to normal function are reduced. The AER further notes that this event does not relate to a cost increase or decrease incurred by the DNSPs. Rather, it would merely compensate the DNSP for lost revenue based on reduced sales. There are no discernable cost outcomes, only increases or decreases in revenue. Changes in revenue are beyond the event of a pass through event, which is limited to changes in costs.

The AER rejects the following proposed events on the basis that they are recovered elsewhere in the regulatory regime:

- a wind farm connection costs event (proposed by Powercor), as the AER considers that these costs are recovered through connection charges[61]

[61] Chapter 5 of the NER governs network connections, including conditions for the connection of generators.

- a network extension for remote generation event (proposed by Powercor) as the AER considers that these costs are recovered through connection charges

- an S factor payout event (proposed by SP AusNet), for the reasons set out in section 16.5.5

- a premium feed in tariff event (proposed by SP AusNet) for the reasons set out in section 16.5.5

- a financial failure of a retailer event (proposed by CitiPower, Powercor, Jemena and United Energy). The AER considers that the appropriate method to mitigate against the risk of such an event is through the prudential requirements contained in cl. 6.21.1 of the NER.[62]

The AER also rejects the force majeure event proposed by United Energy and Jemena on the basis that these types of events will likely be captured in the 'natural disaster' event defined below.

The AER also rejects the asbestos compensation event proposed by Jemena. This is because this is a risk faced by all businesses in the market. It is the responsibility of the purchaser of a business to undertake any due diligence and any consequent risk should be borne by shareholders, not consumers.

The AER accepts the following events as nominated pass through events. The AER will allow these as pass through events for all Victorian DNSPs in the 2011-2015 regulatory control period:

- a declared retailer of last resort event (proposed by CitiPower, Powercor, Jemena and United Energy)

Where a retailer of last resort (ROLR) event is triggered, specified procedures take effect under the *Electricity Industry Act 2000 (Vic).* DNSPs are likely to incur costs in transferring customers of the failed retailer to the retailer of last resort. The AER recognises that these costs may be significant, and cannot be forecast with any certainty at the time of the distribution determination. Moreover, the AER considers that both the likelihood of an event occurring, and the associated costs of the event should it occur, are beyond the reasonable control of the DNSP. The AER further notes that ROLR events are not compensated for elsewhere in the regulatory regime, and that it is not practical to provide self insurance allowances for a ROLR event (as calculating a self insurance premium is problematic, based on a lack of historical data). The AER has generalised the definition of this event so that it may apply to all Victorian DNSPs.

- an insurance event/legal liability above insurance cap event (proposed by SP AusNet and Jemena)

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62 If the DNSP considers this necessary for retailers, cl. 6.21.1 (d) of the NER notes that DNSPs can seek financial guarantees for distribution service charges.

Both SP AusNet and Jemena noted that this event would be triggered where costs are incurred beyond the insurance cap for an insured event. Whilst such an event can be tightly defined, the timing of an insurance cap event cannot be forecast and would largely be triggered by circumstances beyond the DNSP's control. Any breach of an insurance cap would likely incur costs of a high magnitude. However the AER notes that this would not always be the case. For this reason, the AER proposes that such an event could be compensated through a combination of self insurance and pass throughs. The AER envisages that costs above the insurance cap, but below a specified threshold, should be compensated through the provision of a self insurance allowance (as costs within this range are not necessarily of a high magnitude). Costs beyond this cap are eligible to be treated as a pass through event under the relevant provisions of clause 6.6.1 of the NER. The AER has generalised the definition of this event so that it may apply to all Victorian DNSPs. The AER has also included a qualification that this event will not apply where the costs have been incurred as a result of the DNSP's negligence or illegal behaviour. The AER notes EUAA's submission that it is the responsibility of the DNSPs to insure themselves appropriately and efficiently. Whilst this is the case, costs associated with insurance are already recovered through the regulatory regime (through forecast opex). Allowing cost increases (or decreases) to be passed through to consumers is simply an extension of the regulatory regime. Actual cost increases that arise from the default of an insurer could threaten the financial viability of a business (or result in the DNSP earning less than it's expected regulated rate of return) if they are not passed through.

- an insurer credit risk event (proposed by Jemena)

This event is triggered where a DNSP's insurer becomes insolvent, and the DNSP is subject to:

  - higher or lower premiums than those allowed in the distribution determination
  - for claims, higher or lower deductibles

The AER accepts that the occurrence of increased insurance premiums (or deductibles) from external insurers (where the original insurer becomes insolvent) is largely beyond the control of the DNSP (subject to any choice that the DNSP has with regards to insurance companies), and that the costs associated with higher insurance premiums are also beyond the control of the DNSP (in that they cannot be mitigated). The AER acknowledges that such costs should be allowed in the regulatory regime. The AER has revised Jemena's definition for clarity, and removed references to 'JEN' so that the event can apply to all Victorian DNSPs.

The AER also nominates the following event:

- a natural disaster event

The occurrence of natural disasters such as floods, earthquakes, and major storms is entirely beyond the control of the DNSPs. The timing of such an event cannot be determined in advance. Costs incurred as the result of a natural disaster depend on several variables, such the type of event, the magnitude of the event, and the areas of the DNSP's network which are affected (and the extent to which they are affected). Natural disasters are likely to be of a high magnitude or potentially even catastrophic under certain circumstances. For these reasons, such events should not be subject to self insurance, but rather, compensation for them should be deferred until the event actually occurs.

The AER will not include a specific event for the demonstration of smart grids, as proposed by the Minister. Pass through events are limited to costs associated with the provision of direct control services (as classified under the NER).[63] Further, costs associated with this type of event do not meet all of the pass through criteria outline above, which must be satisfied for a pass through event to be included as part of this draft determination. Specifically, this event is not uncontrollable, as it appears (from the Minister's submission) that such an event would occur entirely at the discretion of the DNSP. If it is the DNSP's decision to undertake smart grids, then it cannot be argued that the associated costs are uncontrollable. To the extent that smart grid rollouts relate to changes in the regulatory obligations (or new regulatory obligations or requirements) imposed upon DNSPs, such an event may be covered by the NER prescribed pass through events (see section 16.5 above for further discussion). However, the AER is unable to form a definitive view about this until such an event occurs.

The AER also rejects the s-factor payout (for the 2010 cost outcomes of ESCV's s-factor scheme, as proposed by SP AusNet). The AER further notes that this event does not relate to a cost increase or decrease incurred by the DNSPs. Rather, it would merely compensate the DNSP for increases or decreases in revenue based on a DNSP's actual performance outcomes. There are no discernable cost outcomes. It is also clear that changes in revenue do not meet the definition of 'eligible pass through amount' in Chapter 10 of the NER. This definition clearly excludes 'revenue impacts of an event'. Thus, even if the AER approved an s-factor event, the AER would be unable under clause 6.6.1 of the NER to pass through amounts in respect of such event.

16.6 AER conclusion

In accordance with clause 6.12.1(14) of the NER, the following events are pass through events for the forthcoming regulatory control period, for the Victorian DNSPs:

- a regulatory change event
- a service standard event
- a tax change event
- a terrorism event.

The AER will determine throughout the forthcoming regulatory control period upon application by a DNSP, whether such an event has occurred.

63 See chapter 10 definition of pass through amount.

In assessing an application for a cost pass through event (whether in relation to a specific 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 the relevant DNSP recovers only incremental costs, and the efficiency of the DNSP's decisions and actions in relation to the event, including whether the DNSP has failed to take action to reduce the magnitude of the event.

For the reasons set out above, the AER accepts the following pass through events for the 2011-2015 regulatory control period for the Victorian DNSPs, in accordance with clause 6.12.1(14) of the NER:

- a declared retailer of last resort event (proposed by Jemena, CitiPower, Powercor, and United Energy), defined below:

> A declared retailer of last resort event means the occurrence of an event whereby an existing retailer is unable to continue to supply electricity to its customers and those customers are transferred to the declared retailer of last resort, and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) materially increases the costs of providing direct control services
>
> For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

- insurer credit risk event (proposed by Jemena) defined below:

> An event where the insolvency of the nominated insurers of the DNSP, as a result of which the DNSP:
>
> a) incurs materially higher or lower costs for insurance premiums than those allowed for in the distribution determination; or
>
> b) in respect of a claim for a risk that would have been insured by DNSP's insurers, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy
>
> For this purpose, an event is considered to materially increase or decrease costs where that event an impact of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

- an insurance event (proposed by Jemena), defined below (this replaces SP AusNet's legal liability above insurance cap event):

> An event that would be covered by an insurance policy but for the amount that materially exceeds the policy limit, and as a result the DNSP must bear the amount of that excess loss. For the purposes of this pass through event, the relevant policy limit is the greater of the actual limit from time to time and the limit under the DNSP's insurance cover at the time of making this regulatory proposal. This event excludes all costs incurred beyond an

> insurance cap that are due to the DNSP's negligence, fault, lack of care. This also excludes all liability arising from the DNSP's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by the DNSP.
>
> For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

In addition to these approved pass through events, the AER also nominates the following event, to apply to all Victorian DNSPs:

- a natural disaster event

> Any major fire, flood, earthquake, or other natural disaster beyond the control of the DNSP (but excluding those events for which external insurance or self insurance has been included within the DNSP’s forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to the DNSP of providing direct control services.
>
> For this purpose, an event is considered to materially increase or decrease costs where that event has an impact of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

For the purposes of each of the above events, the word 'materially' means one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

These pass through events and their definition can also be found in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

17 Demand management incentive scheme

17.1 Introduction

This chapter sets out how the AER's demand management incentive scheme (DMIS) will apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy in the forthcoming regulatory control period. The objective of the DMIS is to provide incentives for distribution network service providers (DNSPs) to seek out and implement efficient and innovative non-network solutions in response to growing demand and network constraints, as they arise on the network. The DMIS operates in conjunction with existing incentives in the regulatory framework supporting these objectives. Whilst non-network alternatives can be funded through operating expenditure (opex) and capital expenditure (capex) where they meet the relevant capex and opex criteria and factors under the National Electricity Rules (NER), the DMIS aims to provide scope for new and innovative demand management solutions.

17.2 Regulatory requirements

Clause 6.6.3(a) of the NER states that:

> The AER may, in accordance with the distribution consultation procedures, develop and publish an incentive scheme or schemes (demand management incentive scheme) to provide incentives for Distribution Network Service Providers to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way.

A decision on how the DMIS will apply to a DNSP is a constituent decision of a distribution determination, under clause 6.12.1(9) of the NER.

Under clause 6.4.3(a)(5) of the NER, a DNSP's annual revenue requirement for each regulatory year of the regulatory control period must be determined using a building block approach, including the revenue increments or decrements (if any), arising from the application of the DMIS.

Further, under clause 6.3.2(a)(3) of the NER the AER, in making a building block determination for a DNSP, must specify how the applicable DMIS is to apply to a DNSP.

The AER published its DMIS to apply to Victorian DNSPs on 29 April 2009.[1] The AER set out its likely application of the DMIS for Victorian DNSPs in its Framework and approach paper.[2] The AER proposed to apply two components of the DMIS—part A, the demand management innovation allowance (DMIA) and part B, the forgone revenue component. The proposed annual amount of the DMIA for each DNSP was:

- CitiPower—$200 000

1 The AER's DMIS for the Victorian DNSPs can be found at www.aer.gov.au.

2 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, pp. 114–124.

- Powercor—$600 000
- Jemena—$200 000
- SP AusNet—$600 000
- United Energy—$400 000.

The AER's DMIS also contains a forgone revenue component (part B of the DMIS), that allows the DNSP to recover revenue forgone as a result of successful implementation of demand management strategies (which are funded by the DMIA).

Each Victorian DNSP is subject to the reporting requirements set out in the DMIS. Reporting requirements for the DMIS are discussed further in chapter 21.

17.3 Summary of Victorian DNSP regulatory proposals

17.3.1 Application of the DMIA

CitiPower, Powercor, Jemena and SP AusNet did not propose any alterations to the amount of the DMIA from that proposed in the AER's Framework and approach paper. United Energy proposed an increase in the amount of the DMIA to a total of $10 million for United Energy over the forthcoming regulatory control period. Each Victorian DNSP stated that it will apply the DMIA in the 2011–15 regulatory control period. Each DNSP outlined its approach to the DMIS.

CitiPower and Powercor

CitiPower and Powercor did not propose any changes to the AER's DMIA amount for the forthcoming regulatory control period.[3] Both stated that:

- part A of the DMIS, being the DMIA, will apply to it in the forthcoming regulatory control period.

CitiPower and Powercor did not include a revenue increment of $200 000 for the DMIS building block in their calculations of the annual revenue requirement (ARR) for each regulatory year of the forthcoming regulatory control period in the post-tax revenue model (PTRM), as it expected that the AER would include this as part of its final decision.[4] CitiPower stated that the DMIS will contribute to the continuation of investigations of demand management options for the area supplied by West Melbourne terminal station (WMTS) which is reaching its capacity due to the increased load in the CBD.[5] Powercor indicated that it will continue to fund demand management projects commenced in the current regulatory control period, including:

- demand management at Charlton zone substation

3 CitiPower, *Regulatory proposal*, p. 272; Powercor, *Regulatory proposal*, p. 278.
4 ibid.
5 ibid., p. 243.

- a solar SWER PV systems trial.[6]

Jemena

Jemena stated that it intended to adopt the DMIS consistent with the Framework and approach paper and AER's final DMIS for Victorian DNSPs.[7]

SP AusNet

In its regulatory proposal, SP AusNet stated that it intended to use the DMIA to trial broad-based demand management, non-network solutions, and smart network technologies throughout the regulatory control period.[8]

SP AusNet also noted that it had exhausted its demand management allowance in the current regulatory control period ($600 000 over the period as approved by the Essential Services Commission of Victoria (ESCV)). This allowance was used as follows:

- approximately $0.32 million on adjusting hot water time clocks and meters in the Leongatha, Wonthaggi, Inverloch and Philip Island areas to reduce hot water peak demand. These adjustments have allowed $14.6 million worth of reconductoring capex on the South Gippsland network to be deferred in the current regulatory control period.

- $75 000 in distributed generation to provide network support and defer $6.4 million worth of network augmentation capital expenditure on the Euroa line at Violet Town

- approximately $0.23 million on pole mounted capacitors to improve power factor correction on the Euroa, King Valley and Nagambie lines

- in kind contribution to the Econnect project which investigated the potential impacts of embedded generation on the distribution network.[9]

SP AusNet noted that it would exclude the DMIA allowance from the AER's efficiency benefit sharing scheme (EBSS).

United Energy

United Energy stated that it is broadly supportive of the AER's DMIS.[10] Specifically, it supported:

- that part A of the DMIS, being the DMIA, should take effect over the forthcoming regulatory control period

- flexibility in terms of the timing of the drawdown of the DMIA.[11]

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6 ibid., p. 244.
7 Jemena, *Regulatory proposal,* p. 122.
8 SP AusNet, *Regulatory proposal,* p. 252.
9 ibid.
10 United Energy, *Regulatory proposal*, p. 234.
11 ibid., p. 237.

However, United Energy contended that its allowance ($400 000 per year) is of insufficient magnitude to enable it to undertake comparatively small scale demand management projects in each year of the forthcoming regulatory control period. United Energy, noting that the total DMIA for all Victorian DNSPs over the next regulatory control period is $10 million, stated:

> Pursuant to clause 6.4.3(a)(5) of the NER, UED has included a revenue increment of $10 million (in real 2010 values) for the DMIS building block component. This amount will affect the calculation of the annual revenue requirement (in the PTRM model) for each regulatory year of the next regulatory control period.[12]

17.3.2 Part B—Foregone revenues

CitiPower, Powercor, Jemena, SP AusNet and United Energy each noted their support for the AER's approach under Part B of the DMIS.[13]

17.4 Summary of submissions

The AER received three submissions from the following stakeholders commenting on the DMIS:

- Total Environment Centre (TEC)
- Central Victorian Greenhouse Alliance (CVGA)
- Victorian Employers Chamber of Commerce and Industry (VECCI).

TEC

TEC expressed broad concerns about the underutilisation of demand management in Australia. The TEC stated that the AER should require networks to implement demand management as a first choice over network augmentation where equal to, or more cost effective than, building new infrastructure. The TEC further recommended that demand management targets should be mandated for peak demand on networks.[14]

Several issues raised in the TEC submission were recommendations made in the *Win Win Win Regulating Electricity Distribution Networks for Reliability, Consumers and the Environment—Review of the NSW D-Factor and Alternative Mechanisms to Encourage Demand Management*, by the Institute of Sustainable Futures (ISF). The ISF recommended that the AER:

- align network incentives with consumer and public interest. In particular, incentives against demand management should be avoided in relation to:
  - short term incentives (within regulatory periods) associated with price/revenue control formulae

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[12] ibid., p. 238.

[13] CitiPower, *Regulatory proposal*, p. 273; Powercor, *Regulatory proposal*, p. 278; Jemena, *Regulatory proposal*, p. 122; SP AusNet, *Regulatory proposal*, pp. 254–255 United Energy, *Regulatory proposal*, p. 236.

[14] TEC, *Submission to the Australian Energy Regulator on Victorian DNSPs regulatory proposal*, 11 February 2010, p. 2.

  - long term incentives (between regulatory periods) and the incorporation of capital expenditure into the capital base and mechanisms for sharing efficiency benefits between shareholders and consumers
  - network system development and planning requirements
- in setting its year-to-year price control formula, decouple DNSP and profit from electricity sales volume by applying revenue caps
- apply a D factor in circumstances where it is not possible to apply a revenue cap and create a 'use it or lose it' component in the D factor
- allow recovery of long term demand management costs in a D factor
- permit savings realised from successful demand management to be carried forward (such as deferred or avoided capex)
- undertake balanced prudency review of capex, ensuring that the review of prudency of past and projected capex involves a thorough assessment of the opportunities for deferring capex through demand management
- require DNSPs to demonstrate efforts to procure demand management
- the AER should require DNSPs to publish detailed information annually about the current capacity of the distribution network, current and projected demand and possible options to address any emerging constraints, and conduct and publish annual AER demand management reviews.[15]

The TEC also noted its previously commissioned report entitled *Does current electricity network regulation actively minimise demand side responsiveness in the NEM*? The TEC cited two disincentives to demand management from this report:

1. The weighted average cost of capital (WACC) in the building block approach embeds all profit in providing network services in capex. By contrast, opex is provided at cost, and does not include any profit to the network for spending on any element included in the opex allowance (and as many demand management programs are opex based there is an active disincentive embedded in the building block approach).
2. The ex-ante approach to capex provides networks with the ability to spend capital within the capex allowance, but with no subsequent assessment of its economic efficiency or prudency.[16]

CVGA

The CVGA submitted that costs associated with the connection of embedded generators are within the scope of the DMIS. However, it noted that that the operation

[15] ibid., pp. 3–5.
[16] ibid., pp. 5–6.

of the DMIS is restricted to the benefits the DNSP may obtain through part A of the DMIA.[17]

The CVGA noted the Australian Energy Market Commission's (AEMC) publication, *Review of energy market frameworks in light of climate change policies,* which suggested that the DMIA should be expanded to explicitly consider the connection of embedded generation. The CVGA also noted that the DMIS has very broad scope for discretion at this stage of the process and that the AER could expand the current DMIS to adopt the AEMC's proposals.[18]

The CVGA's submission also stated that the AER should broaden the scope of its upfront, indicative approval process (contained in the DMIS) by allowing a project proponent to request the AER to conduct the upfront indicative approval process. The CVGA submitted that:

> … if a project proponent's approach to the DNSP to seek connection of a distributed sustainable generation project includes the AER's indicative approval for the costs to be included in the DMIA, the scope for the connection proceeding are greatly improved.[19]

The CVGA also argued that the amount of the DMIA should be increased─to 0.5 per cent of the DNSPs' ARR─as the current level of the DMIA is inadequate to allow continued research and development of a range of projects. CVGA further stated that an allowance of 0.5 per cent of ARR:

> … would be in line with the level of funding permitted by Ofgem under the Innovation Funding Incentive (IFI) regime, which it has applied to electricity distributors in the United Kingdom.[20]

The CVGA also proposed that a proportion of the DMIA should be earmarked for connection of distributed sustainable generation projects.[21]

VECCI

VECCI noted that there are potential opportunities for DNSPs to undertake an education program for small businesses. Such education programs would demonstrate to businesses ways in which they can contribute to simultaneously reducing peak demands on the network and reducing carbon emissions.[22]

VECCI stated that it was disappointed at the disjointed approaches to funding such measures in general and in the level of funding provided for programs under the DMIA. It considered that the amount of the DMIA should be reviewed to allow for a

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17 CVGA, *Submission to the AER Victoria DNSP Price Review,* 18 February 2010, p.10–11.
18 ibid., p. 11.
19 ibid, pp. 10–11.
20 ibid, pp. 12–13.
21 ibid.
22 VECCI, *Re: AER review of Victorian distributors regulatory proposals*, 19 February 2010, pp. 17–18.

meaningful education program to be carried out by the DNSPs, directed at behavioural changes targeted at reducing the peak demands on the networks.[23]

17.5 Issues and AER considerations

17.5.1 Amount of the DMIA

United Energy proposed to have its allowance increased to a total of $10 million over the forthcoming regulatory control period, stating that the amount proposed by the AER ($400 000 per regulatory year) was insufficient.[24]

The AER notes that the DMIS is not the only potential source of funding for demand management initiatives. The AER has stated previously that DNSPs may propose opex and capex allowances to fund demand management expenditure, and that this expenditure will be assessed under the opex and capex criteria contained in clauses 6.5.6 and 6.5.7 of the NER.[25] The AER has, on several occasions, noted that the DMIS is intended to be a *modest* allowance for innovative and experimental demand management projects which would be unlikely to be approved under the capex and opex criteria under the NER.[26] Further, the AER has no grounds to accept that customers are willing to bear a material risk for demand management initiatives that are untested and experimental in nature and that have not met the expenditure prudency and efficiency tests under the NER. The AER is required to have regard to such matters under clause 6.6.3(b) of the NER.

The AER notes that in its regulatory proposal, and in response to subsequent questions raised by the AER, United Energy did not expand on the scope of projects that it sought to fund with the DMIA and did not provide adequate justification for why additional DMIA funding should be sought. Further, the AER considers that such an increase in the DMIA would be outside the scope of the DMIS. Under clause 6.6.3(b) of the NER the AER must consider, among other matters, the willingness of customers to fund increased costs incurred through the implementation of a DMIS. There is no evidence to suggest that customers are willing to fund an increase as proposed by United Energy.

For the reasons outlined above, the AER will not increase the allowance provided to United Energy under the DMIA.

The AER notes that it is open to United Energy to propose demand management expenditure under the capex and opex provisions of the NER.

The DMIA will be provided to each DNSP as an ex-ante allowance, consistent with the provisions in the AER's DMIS. However, each DNSP will have the option of seeking an upfront indicative approval of DMIA funded projects at the beginning of

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23 ibid.

24 United Energy, *Regulatory proposal*, p. 236.

25 AER, *Final decision on DMIS to apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy*, p. 7; AER Framework and approach paper for CitiPower, Powercor, Jemena, SP AusNet and United Energy, pp. 114–124.

26 AER, *Final decision on DMIS to apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy*, p. 7.

each regulatory year. This involves an in principle examination of whether proposed expenditure under the DMIA is likely to satisfy the ex-post assessment criteria contained in the DMIS.

Finally, the AER confirms that the Victorian DNSPs will have revenue increments in each regulatory year of the following amounts over the forthcoming regulatory control period consistent with the DMIS:

- CitiPower—$200 000
- Powercor—$600 000
- Jemena—$200 000
- SP AusNet—$600 000
- United Energy—$400 000.

17.5.2 Treatment of capital expenditure under the DMIA

SP AusNet sought confirmation from the AER that actual capex incurred in the forthcoming regulatory control period, be it demand management related or otherwise, will be rolled into the regulatory asset base (RAB) where it satisfies Schedule 6.2.1(e) of the NER.[27]

SP AusNet also noted that capex spent beyond the DMIS cap, which will not have been recovered during the forthcoming regulatory control period, will be rolled into the RAB for the 2016–2- regulatory control period without ex-post assessment.[28]

This issue has been previously considered by the AER in the development of the DMIS for Victoria.[29] At that time, the AER noted that it cannot pre-empt approval or rejection of any expenditure incurred in the forthcoming regulatory control period that is proposed to be rolled into the RAB in the subsequent regulatory control period. Such decisions are constituent decisions to be made under the NER for the relevant regulatory control period. To pre-empt this would be in conflict with the AER's obligations and duties under the National Electricity Law (NEL), NER and administrative law. The AER will assess all expenditure at the time of the regulatory proposal for the relevant regulatory control period in the context of the NER, NEL and any other relevant regulatory instruments in force at that time. Expenditure that meets the relevant capex provisions under the NER would be rolled into the RAB.

17.5.3 Stakeholder submissions

The AER has considered the issues raised by the TEC, CVGA and VECCI in response to the Victorian DNSPs' regulatory proposals.

27 SP AusNet, *Regulatory Proposal*, p. 253.
28 ibid.
29 AER, *Final decision on DMIS to apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy*, p. 16.

Several issues raised by TEC have been considered previously in the development of the AER's jurisdictional demand management schemes.

In particular, the AER notes that the following options proposed by the TEC cannot be undertaken under the NER:

- The AER cannot require that savings from deferred capex be retained into future regulatory control periods nor pre-empt decisions that it will make in future regulatory determinations. Matters relevant to any future determination will be taken into consideration at that time.[30]

- The AER is not able to undertake ex-post prudency reviews of capex, to ensure that demand management options have been considered, as proposed by TEC. TEC noted that an ex-ante approach to capex provides networks with the ability to spend capital within the capex allowance, but with no subsequent assessment of its economic efficiency or prudency. However, the NER framework explicitly provides an ex-ante treatment of capex allowances. Any ex-post prudency assessment is beyond the scope of the AER's role under the NER.

- As the form of control has been set out in the AER's Framework and approach paper, the AER cannot decouple a DNSP's profit from its electricity sales volume. The AER, however, considers that the application of the forgone revenue component in the DMIS counteracts the perceived disincentive to undertake demand management initiatives. Further, the AER cannot mandate a revenue cap form of control at this stage in the determination process. While a revenue cap is a permissible form of control for standard control services under Part C of the NER, the AER notes that the NER also states that the form of control set out in its Framework and approach paper cannot be departed from in the distribution determination process.[31]

The TEC also raised several issues in relation to demand management reporting. The AER notes that the Victorian DMIS contains broad reporting requirements, which require consistent reporting of demand management across all Victorian DNSPs. The AER has previously stated that this information will be available on its website for other industry members and stakeholders generally:

> This information…. will be provided by each DNSP as part of its reporting obligations under the DMIS, will be made publicly available on the AER’s website. This will allow information to be accessible to stakeholders, and other DNSPs wishing to undertake DMIA expenditure. The AER considers that there is merit in creating a public database of demand management projects and programs in the future and will investigate this as a part of the national DMIS.[32]

[30] AER, *Final decision on DMIS to apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy,* p. 19.
[31] NER, cl. 6.12.3(c)
[32] AER, *Final decision on DMIS to apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy,* p. 19.

In relation to TEC's assertion that the AER should apply a D factor to the Victorian DNSPs, the AER notes that this issue was explicitly considered in finalising the Victorian DMIS. The final decision stated:

> Whilst the AER is not opposed to the application of a D factor mechanism in principle, the results of the D factor applied in NSW are not conclusive and findings about the scheme's potential to apply in other jurisdictions cannot be made at this time. The AER has previously stated that observation and analysis of D factor outcomes over the 2009–14 regulatory control period in NSW will provide a better platform from which to consider the effectiveness of this mechanism and its potential future application. Whilst acknowledging initial reductions in planned capex that the D factor scheme has enabled in NSW, two years of data is not sufficient to draw conclusions or as a basis for the introduction of a D factor scheme in other jurisdictions. However, the AER will monitor the progress of the D factor scheme and consider it as part of the national DMIS when more conclusive evidence of the D factor's success is available. Data collected as part of the reporting requirements under the NSW/ACT DMIS will be made publicly available.[33]

The CVGA submitted that costs associated with the connection of embedded generators are within the scope of the DMIS. It further argued that, given the uncertain nature of these connections, the AER should allocate a proportion of the DMIA for connection of distributed sustainable generation projects.

The AER considers that expenditure for the connection of embedded generators would likely fall within the scope of the DMIA and that Victorian DNSPs may utilise funds under the DMIA for this purpose.

In its recent review of demand side participation in the NEM, the AEMC made recommendations regarding the regulatory framework for connection of embedded generation. In relation to the DMIS, the AEMC recommended that the DMIS in chapter 6 of the NER be amended to become the 'demand management and embedded generation connection incentive scheme'.[34] The recommendation is based on the AEMC's view that there may be a need to provide additional incentives for DNSPs to innovate for the connection of embedded generation.[35] The recommendations, which are yet to be considered by the Ministerial Council on Energy (MCE), were not proposed by the AEMC with the aim of providing a different avenue for funding of embedded generator connections, but rather to provide incentives for innovation in respect of these connections. However, the AER notes that to the extent expenditure on innovation in respect of connection of embedded generators is undertaken for demand management purposes, the expenditure would likely be consistent with the DMIS. The AER notes that the AEMC also highlighted a key potential barrier to connection of embedded generation. This appears to relate to issues of subjectivity regarding technical standards. The AER considers that this is a separate and distinct matter from the DMIS.

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33 AER, *Final decision on DMIS to apply to CitiPower, Powercor, Jemena, SP AusNet and United Energy*, p. 12.
34 AEMC, *Final report, Review of demand-side participation in the NEM*, December 2009, pp. 86–87.
35 ibid., p. viii.

The CVGA also asserted that the upfront approval criteria in the Victorian DMIS should be revised so that proponents of projects can approach the AER to seek indicative approval for certain projects. The AER considers that this is a valid option, and that network users can approach the AER to have it provide an in principle view as to whether or not the project would likely fit within the DMIA assessment criteria contained in the DMIS. However, the AER does not consider that it needs to reopen and amend the DMIS. The AER notes that this is not a definitive approval, nor will it negate the need for ex-post assessment under the DMIS. While it may provide indicative advice to a project proponent, the AER will not require the DNSP to undertake that project. Rather, the AER envisages that such a process would provide greater transparency in the regulatory process and provide the project proponent with information which will inform its business case to the DNSP.

The CVGA and VECCI both argued that the amount of the DMIA should be increased.[36]

The AER has been monitoring a number of reviews that could impact on its approach to demand management, specifically, the review by AEMC of energy market frameworks in light of climate change policies, and the second stage of the AEMC's review of demand-side participation in the NEM. These reviews have now been published. Recommendations have been made by the AEMC regarding the future design of a national DMIS and the incentives for efficient connection of embedded generation, but these recommendations are yet to be considered by the MCE. The AER will consider the MCE's decision, and also the development of the third stage to the AEMC's review,[37] before developing a revised or national DMIS.

17.6 AER conclusion

In accordance with clause 6.12.1 (9) of the NER, the AER's decision in relation to the application of the DMIS is below. The AER's decision on the application of the DMIS is also set out in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

The AER maintains its position, as set out in its Framework and approach paper, to apply the DMIS to CitiPower, Powercor, Jemena, SP AusNet and United Energy. The DMIS will comprise of a part A (the DMIA component) and a part B (foregone revenue component). Part A will be capped in the forthcoming regulatory control period. The relevant annual caps are as follows:

- CitiPower—$200 000 ($1 million over the regulatory control period)
- Powercor—$600 000 ($3 million over the regulatory control period)
- Jemena—$200 000 ($1 million over the regulatory control period)
- SP AusNet—$600 000 ($3 million over the regulatory control period)
- United Energy—$400 000 ($2 million over the regulatory control period).

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36 ibid, pp. 12-13, VECCI, *Submission to the AER*, p. 17–18.
37 AEMC, *Final report, Review of demand-side participation in the NEM*, December 2009, p. vi.

The capped amount will be allocated to CitiPower, Powercor, Jemena, SP AusNet and United Energy as an ex-ante allowance, in five equal instalments. 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.

18 Building block revenue requirements

18.1 Introduction

This chapter sets out the AER's calculation of annual revenue requirements for each Victorian DNSP, for the provision of standard control services for each year of the forthcoming regulatory control period. This chapter also sets out X factor values to be applied as part of the weighted average price caps (WAPC) to apply to the standard control services provided by each DNSP.

18.2 Regulatory requirements

Clause 6.3.2(a) of the National Electricity Rules (NER) states that the AER's building block determination must specify:

(1) the DNSP's annual revenue requirement for each regulatory year of the regulatory control period;

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

(3) how any applicable efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS) or demand management incentive scheme (DMIS) are to apply to the DNSP;

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

(5) any other amounts, value or inputs on which the building block determination is based

Clause 6.5.9 of the NER requires a building block determination to include the X factor for each year of the regulatory control period. The AER must set the X factor with regard to the DNSP's total revenue requirement for the period. The X factor must be set to equalise (in net present value terms) the revenue to be earned from the provision of standard control services with the total revenue requirement attributable to those services. The X factor must also minimise variance between expected revenue and the annual revenue requirement for the last year of the regulatory control period.

A DNSP's building block proposal must be prepared in accordance with the AER's post-tax revenue model (PTRM) and the requirements of Part C of chapter 6 and Schedule 6.1 of the NER. The building block proposal must also comply with the requirements of any relevant regulatory information instrument, such as a regulatory information notice (RIN).

Clause 6.10.2(a)(3) of the NER requires the AER to publish its reasons for its draft constituent decisions made in accordance with rule 6.12. The constituent decisions dealt with in this chapter are:

- a decision to approve or refuse to approve the annual revenue requirement for the DNSP[1]
- decisions on other appropriate amounts, values or inputs[2]
- a decision on the X factor (as it relates to the control mechanism discussed in chapter 4)[3]

Under clause 6.12.3(d) the AER must approve annual revenue requirements if it is satisfied that they have been calculated using the PTRM on the basis of amounts proposed by the DNSP and accepted by the AER, or otherwise determined by the AER under Part C of chapter 6.

18.2.1 Annual building block revenue requirement

Clause 6.4.3(a) of the NER defines and details the building blocks that form the annual revenue requirement as:

- indexation of the RAB
- return on capital
- depreciation
- estimated cost of corporate income tax
- revenue increments or decrements arising from the AER's efficiency benefit sharing scheme (EBSS), service standards performance incentive scheme (STPIS) or demand management incentive scheme (DMIS)
- other revenue increments or decrements arising from the application of a control mechanism in the previous regulatory control period
- forecast operating expenditure (opex).

18.2.2 Post-tax revenue model

The PTRM published by the AER under clause 6.4.1 of the NER sets out how the annual revenue requirement is to be calculated. Clause 6.4.2 specifies that the PTRM must include:

- a method that is likely to result in the best estimates of expected inflation
- the timing assumptions and associated discount rates applicable to the calculation of building blocks in clause 6.4.3 of the NER
- the manner in which working capital is to be treated

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1 NER, cl. 6.12.1(2)(i).
2 NER, cl. 6.12.1(10).
3 NER, cl. 6.12.1(11).

- the manner in which the estimated corporate income tax is to be calculated.

A DNSP's building block proposals must be prepared in accordance with the AER's PTRM under clause 6.3.1.

18.3 Summary of Victorian DNSP regulatory proposals

The Victorian DNSPs' calculations of annual revenue requirements and X factors were contained in the completed PTRMs submitted as part of their regulatory proposals. These are summarised in tables 18.1 to 18.10 below. The proposed X factors result in the net present values (NPV) of the annual revenue requirements and expected revenues being equal over the regulatory control period for all Victorian DNSPs.

The average price increases proposed across the Victorian DNSPs from 1 January 2011 range from 46.3 per cent for SP AusNet to 10.1 per cent for CitiPower. Proposed price increases in the subsequent years range from 8.0 per cent for CitiPower to 3 per cent for Jemena.

Table 18.1 CitiPower proposed annual revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		33.20	36.67	40.21	44.18	49.25
Return on capital		140.16	159.73	181.58	204.25	226.83
Tax allowance		10.46	11.27	11.27	11.75	13.15
Operating expenditure		46.71	46.96	51.29	53.99	51.83
Carryover amounts		–	–	–	–	–
Annual revenue requirements		230.53	254.63	284.36	314.18	341.06
Expected revenues	208.46	235.21	259.79	281.95	305.95	339.03
Forecast CPI (per cent)		2.44	2.44	2.44	2.44	2.44
X factors (per cent)		–10.10	–8.00	–8.00	–8.00	–8.00

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

CitiPower proposed an X factor of –10.1 per cent (that is, a real increase) for the first year of the forthcoming regulatory control period and –8 per cent for subsequent years. The resulting difference between the annual revenue requirement and forecast revenue in the final year is $2.03 million or –0.59 per cent.

Table 18.2 CitiPower proposed annual revenue requirements and expected revenues ($’m, nominal)

	NPV	2011	2012	2013	2014	2015
Annual revenue requirements	1035.64	230.53	254.63	284.36	314.18	341.06
Expected revenues	1035.64	235.21	259.79	281.95	305.95	339.03
Difference (per cent)	–	–1.99	–1.99	0.85	2.69	0.60

Source: CitiPower PTRM.

Table 18.3 Powercor proposed annual revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		64.27	72.68	81.24	90.30	101.48
Return on capital		240.63	268.82	296.94	326.74	358.92
Tax allowance		10.57	12.21	14.06	16.10	18.81
Operating expenditure		185.23	172.02	187.53	206.72	197.63
Carryover amounts		28.99	25.75	6.28	–6.58	–
Annual revenue requirements		529.69	551.49	586.05	633.28	676.83
Expected revenues	416.89	522.52	557.89	590.66	628.54	678.53
Forecast CPI (per cent)		2.44	2.44	2.44	2.44	2.44
X factors (per cent)		–22.30	–5.00	–5.00	–5.00	–5.00

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

Powercor proposed an X factor of –22.30 per cent for 2011 and –5 per cent for subsequent years of the forthcoming regulatory control period. The difference between Powercor’s expected revenue and required revenue in the final year is $1.69 million or 0.25 per cent.

Table 18.4 Powercor proposed annual revenue requirements and expected revenues ($’m, nominal)

	NPV	2011	2012	2013	2014	2015
Annual revenue requirements	2180.38	529.69	551.49	586.05	633.28	676.83
Expected revenues	2180.38	522.52	557.89	590.66	628.54	678.53
Difference (per cent)	–	1.37	–1.15	–0.78	0.75	–0.25

Source: Powercor PTRM.

Table 18.5 Jemena proposed annual revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		28.37	34.38	40.74	40.72	39.18
Return on capital		82.06	93.57	105.28	115.68	124.87
Tax allowance		12.55	7.68	9.56	9.86	10.07
Operating expenditure		63.28	62.43	66.38	72.15	71.03
Carryover amounts		–	–	–	–	–
Annual revenue requirements		206.36	212.39	238.85	239.22	245.16
Expected revenues	158.19	213.88	219.07	224.90	234.07	247.56
Forecast CPI (per cent)		2.47	2.47	2.47	2.47	2.47
X factors (per cent)		–39.64	–3.00	–3.00	–3.00	–3.00

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

Jemena proposes X factors of –39.64 per cent (that is, a real increase) for the first year of the forthcoming regulatory control period and –3 per cent for subsequent years. The resulting difference between Jemena’s annual revenue requirement and expected revenue in the final year of the regulatory control period is $2.40 million or 0.98 per cent.

Table 18.6 Jemena proposed annual revenue requirements and expected revenues ($’m, nominal)

	NPV	2011	2012	2013	2014	2015
Annual revenue requirements	839.07	206.36	212.39	238.85	239.22	245.16
Expected revenues	839.07	213.88	219.07	224.90	234.07	247.56
Difference (per cent)	–	–3.52	–3.05	6.20	2.20	–0.97

Source: Jemena PTRM.

Table 18.7 SP AusNet proposed annual revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		95.9	62.6	70.1	74.6	64.9
Return on capital		228.8	249.0	277.4	302.8	329.0
Tax allowance		13.9	3.7	6.9	9.4	11.3
Operating expenditure		171.8	181.2	189.9	199.1	207.2
Carryover amounts		14.7	-20.2	-2.4	5.4	3.1
Annual revenue requirements		525.2	476.3	541.8	591.2	615.5
Expected revenues	369.4	516.3	517.4	527.2	566.2	618.6
Forecast CPI (per cent)		2.40	2.40	2.40	2.40	2.40
X factors (per cent)		–46.25	–5.50	–5.50	–5.50	–5.50

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

SP AusNet proposed X factors of –46.25 per cent for the first year of the forthcoming regulatory control period and –5.50 per cent for subsequent years. The resulting variance between the annual revenue requirement and expected revenue in the final year of the regulatory control period is $3.09 million or 0.50 per cent.

Table 18.8 SP AusNet proposed annual revenue requirements and expected revenues ($’m, nominal)

	NPV	2011	2012	2013	2014	2015
Annual revenue requirements	2018.07	525.19	476.27	541.89	591.18	615.53
Expected revenues	2018.07	516.28	517.42	527.21	566.23	618.62
Difference (per cent)	–	1.73	–7.95	2.78	4.41	–0.50

Source: Jemena PTRM.

Table 18.9 United Energy proposed annual revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		51.73	56.42	62.96	67.02	72.34
Return on capital		152.84	167.93	181.80	194.92	206.04
Tax allowance		6.77	8.30	9.94	12.77	14.74
Operating expenditure		126.88	126.17	128.70	131.21	134.09
Carryover amounts		9.42	6.35	–1.69	–1.53	–
Annual revenue requirements		347.64	365.16	381.71	404.39	427.21
Expected revenues	292.46	348.93	367.21	382.11	400.44	426.36
Forecast CPI (per cent)		2.44	2.44	2.44	2.44	2.44
X factors (per cent)		–16.81	–4.00	–4.00	–4.00	–4.00

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

United Energy has proposed X factors of –16.81 per cent for the first year of the forthcoming regulatory control period and –4 per cent for subsequent years. The resulting variance between the annual revenue requirement and expected revenue in the final year of the regulatory control period is $0.86 million or 0.20 per cent.

Table 18.10 United Energy proposed annual revenue requirements and expected revenues ($'m, nominal)

	NPV	2011	2012	2013	2014	2015
Annual revenue requirements	1413.78	347.64	365.16	381.71	404.39	427.21
Expected revenues	1413.78	348.93	367.21	382.11	400.44	426.36
Difference (per cent)	–	–0.37	–0.56	–0.10	0.99	0.20

Source: United Energy PTRM.

18.4 Summary of submissions

Submissions by the Energy Users Association of Australia (EUAA), Energy Users Coalition of Victoria (EUCV), and Mars Petcare all expressed concerns about the significant increases in prices resulting from the Victorian DNSPs' proposals.

The EUAA expressed concern about the large price increases on its members especially due to convergence of pricing pressure as a result of the Australian Government's climate change mitigation policies, including the carbon pollution reduction scheme and the recently expanded energy target. The EUAA urged the AER to determine prices through setting approved costs and energy forecasts. To achieve this, the AER must fulfil the requirement under the NER to benchmark these energy businesses. The EUAA also urged the AER to consider price impacts in the context of the national electricity objective and expressed concern that price impacts have not been given sufficient weight in recent AER determinations. The EUAA recommended that price increases should be communicated to users well in advance and welcomed the proactive approach taken by the AER in the Queensland and South Australian determinations in this regard.[4]

The EUCV stated that the proposed price increases are excessive and unjustifiable and will create hardship for Victorian customers already suffering from the global financial crisis. The EUCV also noted that price increases will be disproportionately borne by poorer households.[5]

Mars Petcare noted that it considered the proposal submitted by SP AusNet and did not accept the justification for SP AusNet’s proposed large X factors. Mars Petcare noted that poor performance in SP AusNet's network services had affected its operations. Mars Petcare noted that SP AusNet’s regulatory proposal cited factors affecting the proposed price increases such as customer expectation, climate change and the financial environment and that these issues also affect Mars Petcares’ operations, however Mars Petcare has vigorously adapted its business in response to these factors.[6]

18.5 Issues and AER considerations

This section begins with an analysis of the DNSPs’ proposed X factors according to their contributing factors, as well as a trend analysis of historic and proposed revenue outcomes.

The remainder of the chapter then addresses each of the building blocks proposed by each DNSP and a summary of the AER decision on each. Further details on the AER’s consideration of the DNSPs’ proposed opex, depreciation and corporate income tax are contained in chapters 7, 10 and 12 of this decision. The return on capital using the weighted average cost of capital (WACC) determined in chapter 11 is outlined here. The AER's decision on the DNSPs' capex allowances is discussed in chapter 8 and indirectly affects the building blocks discussed below.

18.5.1 Contribution to proposed X factors

Table 18.11 decomposes the DNSPs proposed X factors into various building block and other elements. For the purposes of comparison across the DNSPs, the data in this table has been calculated by assuming that X factors for years two to five of the forthcoming regulatory control period are equal to zero, hence all required price changes are applied in year one, or as the 'P 0'.

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4 EUAA, *AER Review of Victorian electricity distribution prices and distributors’ proposals for the period 2011–2015, 10 February 2010,* p. 6.

5 EUCV *Victorian Electricity Distribution Revenue Reset Applications from CitiPower, Jemena, Powercor, SP AusNet and United Energy,* February 2010 p. 3

6 Mars Petcare, *Response to proposed pricing structure of SPI Electricity,* 11 February 2010, p. 2.

Table 18.11 Victorian DNSP proposed per cent contribution to 'P 0'

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
P0	–10.13	–22.30	–39.64	–46.25	–16.81
X for years 2 to 5	–8.00	–5.00	–3.00	–5.50	–4.00
P0 (assume X2–5 = 0)	**–27.43**	**–34.00**	**–47.42**	**–61.28**	**–25.61**
Realignment of tariff revenue to costs in 2010	3.63	–1.63	3.11	–8.94	6.80
Energy / demand forecasts	–2.32	–2.28	–14.56	–23.49	–4.10
WACC (incl. franking)	–19.01	–15.65	–15.98	–16.22	–12.13
O & M	–1.59	–5.20	–5.50	–12.29	–7.75
Capex/depreciation	–8.74	–9.29	–9.53	–11.59	–4.33
Accelerated depreciation	0.00	0.00	0.00	0.00	–3.80
Efficiency carryover	0.00	–2.77	–6.50	0.58	–0.96
ESC S factor removal	1.49	3.35	5.08	11.22	–1.15
Other	–0.90	–0.53	–3.54	–0.55	1.80
Total increase from 2010	**–27.43**	**–34.00**	**–47.42**	**–61.28**	**–25.61**

Note: Negative amounts correspond to price increases in the CPI–X equation.
Source: AER analysis.

'Realignment of tariff revenue to costs in 2010' refers to the level to which current prices need to be adjusted to align costs and revenues at the end of the current regulatory control period (that is, before changes in costs and revenues from 2011 are factored into prices). 'Energy forecasts' are also a driver of price (as opposed to cost) increases as sales quantities affect expected revenues, which are set with respect to the DNSPs' building block costs.

On the cost side, the table shows each building block element described in section 18.2.1, calculated by assuming particular costs reflect 2010 levels.

The key observations from table 18.11 are:

- the X factors proposed by each DNSP are significant, particularly for SP AusNet and, to a lesser extent, Jemena
- the biggest contributor to proposed increase in costs is the proposed nominal vanilla WACC of 10.86 per cent, compared to the 8.53 per cent derived from the Essential Services Commission of Victoria's (ESCV) 2006 determination. The difference of 2.33 per cent arises primarily because of proposed parameters that have been affected by the recent global financial crisis:

    - a proposed market risk premium of 8 per cent, compared to the 6 per cent used by the ESCV
    - an indicative debt risk premium of 4.71 per cent, compared to 1.425 per cent determined by the ESCV.[7]
- opex is a key driver for the increase in costs for both SP AusNet and United Energy
- capex and depreciation are also a significant contributors for cost increases across the DNSPs
- Jemena's proposed cost increase is affected by a higher reward for gains arising under the ESCV's efficiency carryover mechanism
- SP AusNet has proposed significant cost increase despite been offset by a large penalty arising from S factor outcomes from the current regulatory control period.

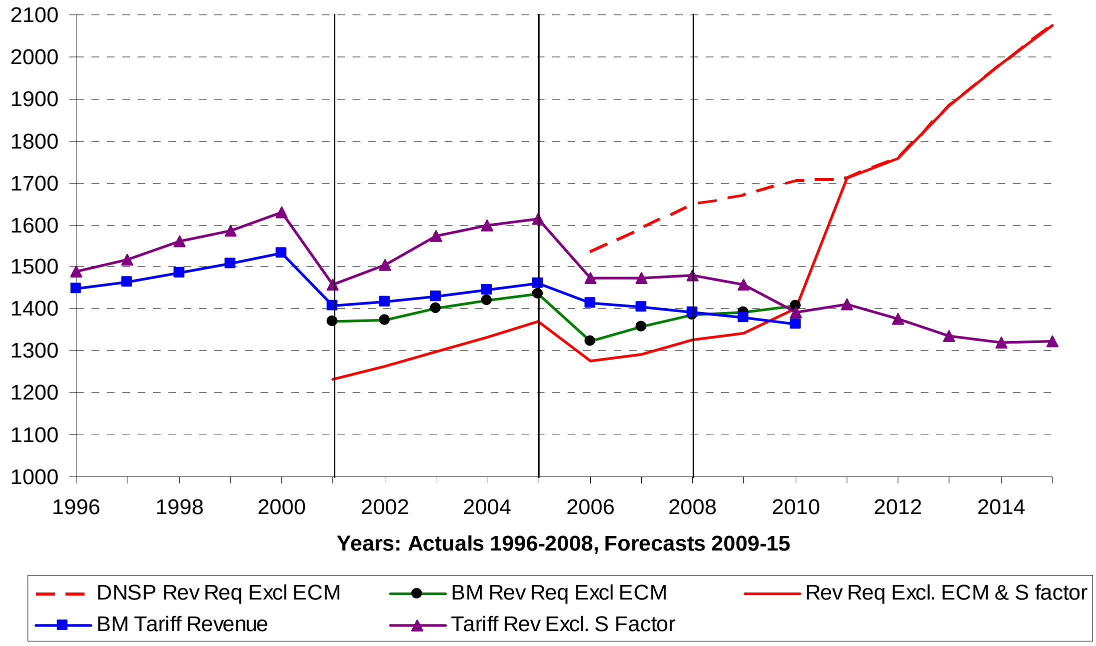
18.5.2 Historical revenue comparisons

This section analyses the Victorian DNSPs' proposed building block revenues in the context of historical outcomes. This analysis reflects similar comparisons outlined previously in this decision for particular building block components and helps to inform the AER of the overall merits of the proposals in the context of the DNSP's behaviour in prior resets.

Figure 18.1 presents combined data for the five DNSPs. It shows the annual revenue requirements set by the ESCV from 1996 to 2010 and proposed requirements for the forthcoming regulatory control period. Also compared are 'actual' building block costs, based on actual reported expenditures and excluding incentive payments (for example S factor and efficiency carryover amounts). Similarly, forecast and actual tariff revenues are plotted. Tariff revenue for 2010 to 2015 presumes that 2010 prices apply for the forthcoming regulatory control period, hence revenues are only affected by changes in sales quantities.

7 *ESCV, Electricity Distribution Price Review 2006–10,* Volume 1, October 2006, p. 332; AER analysis.

Figure 18.1 Building Block cost and revenue profile for Victorian DNSPs ($'m, 2010)



Source: AER analysis

Figure 18.1 illustrates:

- the forecast revenue requirements for the 2011–15 regulatory control period are 42 per cent above the 'actual' building block costs incurred over 2006–10
- the massive increases in expenditures from 2008 (where actual data ceases and forecasts begin) and highlights the need for the AER to critically assess any expenditure claims above historical levels
- the Victorian DNSPs have generally spent much less than the allowances requested but also less than the subsequent allowances set by the ESCV, notwithstanding the reductions imposed by the ESCV
- while forecast revenues rise and fall in line with the real price increases and decreases imposed by the ESCV, actual revenues are consistently higher than those forecast, reflecting the operation of the weighted average price cap approach
- Victorian DNSPs have consistently earned revenues that are above those forecast by the ESCV. On average, the Victorian DNSPs have earned revenues 6.1 per cent above those that were forecast by the ESCV for each year.[8]

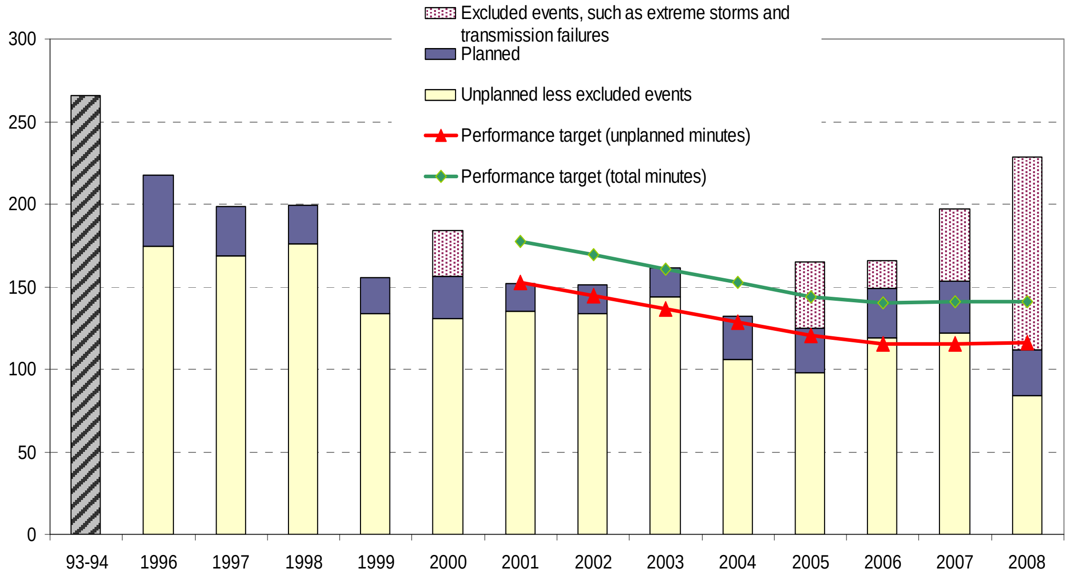
In presenting historic data, however, the reasons for outperformance with respect to allowances should be considered. In addition to inaccurate forecasting, DNSPs may have undertaken efficiency improvements, chosen to efficiently defer expenditure, or

[8] Based on actual revenues earned (less S factor payments) and revenues forecast in determinations by the ESCV / Victorian Office of the Regulator General for years 1996 to 2008.

may have not adequately maintained their networks and taken on higher operational risks.

In exploring the reasons for outperformance, figure 18.2 shows the combined supply reliability of the Victorian DNSPs, including planned and unplanned events, as well as events that were outside the control of the DNSPs (for example extreme storms). The figure also shows the pattern of supply reliability in relation to the ESCV's targets for progressive annual improvements in unplanned and total minutes off supply.

Figure 18.2 Average total minutes off supply per Victorian customer (minutes)



Source: AER, *Victorian electricity distribution businesses comparative performance report*, 2009, p. 5.

The data demonstrate that the Victorian DNSPs have generally improved performance since 1996, with performance stabilising by around 2005, generally in line with the targets set by the ESCV. This supports the conclusion that, for the average network user, the Victorian DNSPs' underspending of the ESCV's expenditure allowances has not come at a cost of network reliability.[9]

Obtaining better information on network performance is a key driver in the AER's intention to establish a monitoring regime for outputs (see chapter 21) which will inform this type of analysis in future review processes. Such analysis would also appropriately address concerns from stakeholders such as Mars Petcare and the EUCV about large price increases without any apparent improvements in service quality.

9 However, as stated in section 15.7.3 of this decision, the AER notes that SP AusNet's historical level of supply reliability has been lower than other DNSPs, in particular Powercor whose network has a similar mix of urban and rural components as SP AusNet. The AER proposes to assign a higher incentive/penalty rate in terms of revenue adjustment under the STPIS to incentivise SP AusNet to improve supply reliability.

18.5.3 General price impacts

In the context of the concerns expressed by several stakeholders, table 18.12 lists the real percentage increases in a typical residential customer's annual bill as a result of the Victorian DNSPs' proposed X factors, in the first year of the forthcoming regulatory control period and the average change for each of the subsequent four years.

Table 18.12 Victorian DNSP proposed cost increases for annual electricity bill ($, 2010)

	2011	2012 to 2015
CitiPower	48.5	38.4
Powercor	107.0	24
Jemena	190.1	14.4
United Energy	80.6	19.2
SP AusNet	222.2	26.4

Note: Assumed end use bill of $1200 per year, of which 40 per cent is attributed to distribution costs.

In presenting this information the AER emphasises that the Victorian DNSPs have forecast an overall reduction in consumption and shifts in consumption from peak to off peak periods, in response to energy efficiency policies and time of use tariffs. Hence when overall price changes are viewed in the absence of consumption changes (as done for table 18.12) this may overstate the expected impact on customer bills.

The AER's draft decisions on the Victorian DNSPs' X factors are listed in section 18.7 below. The corresponding impact of the AER's decision on end use customer bills is presented in table 18.13.

Table 18.13 AER decision on real cost increases on annual electricity bill ($, 2010)

	2011	2012 to 2015
CitiPower	–34.9	4.8
Powercor	–39.1	0.0
Jemena	–7.0	–10.8
United Energy	–94.0	12.0
SP AusNet	–21.4	0.0

Note: Assumed end use bill of $1200 per year, of which 40 per cent is attributed to distribution costs.

In some instances, namely for United Energy and CitiPower, the AER's X factors result in price increases in the latter years of the forthcoming regulatory control period. Conversely, the X factors determined for Jemena result in a small initial price decline in 2011, with further declines in the latter years of the forthcoming regulatory control period. Clause 6.5.9(b) of the NER requires the AER's X factors to be such that the NPVs of the expected revenue and building block total revenue requirement for the forthcoming regulatory control period are equal, and that the difference between expected revenues and building block costs in 2015 are minimised. Within these requirements the AER is afforded some discretion in determining X factors which may vary across particular years of the forthcoming regulatory control period.

Under section 16 of the NEL, the AER must exercise its economic functions in a manner that will, or is likely to, contribute to the achievement of the national electricity objective. Under section 16(2) of the NEL, the AER must have regard to the revenue and pricing principles when exercising its discretion in making those parts of a distribution determination relating to direct control network services. When determining X factors within the scope of clauses 6.5.9(b)(1) and (2), the AER has considered the need to provide DNSPs with a reasonable opportunity to recover at least efficient costs (including in particular regulatory years) and other relevant revenue and pricing principles, as well as the long term interests of consumers. In this context the AER notes the concerns expressed by stakeholders about the large price increases implied from the Victorian DNSPs' proposals that contrasts with the AER's draft decision providing for real reductions in average network prices. Specific considerations on the X factors determined for each DNSP are outlined in section 18.7 below.

Issues regarding the communication of tariffs and tariff design will be addressed by the AER under Part I of Chapter 6 of the NER in relation to the Victorian DNSPs' pricing proposals which follow the AER's final determination in October 2010. The AER is aware of the significantly compressed timeframes provided under the NER and expects to engage with the Victorian DNSPs and stakeholders regarding tariff issues prior to commencement of the consultation process prescribed in the NER.

For comparison with table 18.11 above, the AER has decomposed the determinants of its draft decision X factors with respect to 2010 prices in table 18.14. As per table 18.11, the data in this table has been calculated by presuming that X factors for years two to five of the forthcoming regulatory control period are equal to zero, hence all required price changes are applied as a comparative once off price adjustment in 2011 (that is, the 'P 0').

Table 18.14 AER draft decision—per cent contribution to 'P 0'

	CitiPower	Powercor	Jemena	SP AusNet	United Energy
P0 (assume X2–5 = 0)	**6.25**	**8.14**	**3.62**	**4.46**	**16.97**
Realignment of tariff revenue to costs in 2010	7.01	7.24	8.21	–5.15	9.65
Energy / demand forecasts	4.39	7.22	3.64	8.02	6.00
WACC (incl. franking)	–5.35	–4.76	–4.02	–5.63	–4.10
O & M	0.30	0.23	–0.06	–1.58	1.63
Capex/depreciation	–2.77	–4.35	–0.38	–3.75	–1.49
Accelerated depreciation	0.00	0.00	0.00	0.00	0.00
Efficiency carryover	0.95	–0.51	–6.96	1.83	0.00
ESC S factor removal	1.55	2.90	3.03	10.53	5.15
Other	0.16	0.18	0.15	0.21	0.13
Total Increase from 2010	**6.25**	**8.14**	**3.62**	**4.46**	**16.97**

Note: Positive amounts correspond to price decreases in the CPI–X equation

The data in table 18.14 indicate that the overall price decreases resulting from the AER's draft decision, with respect to 2010 prices, are mainly the result of:

- the continued increase in energy sales, as determined by the AER
- the need to realign (reduce) revenues towards underlying costs at the commencement of the regulatory control period (this is a significant contributor to United Energy's large P0)
- removal of amounts arising from application of the ESCV's S factor mechanism.

Offsetting these impacts is the AER's WACC of 9.68 per cent, which is above the equivalent 8.53 per cent nominal vanilla WACC determined by the ESCV for the current regulatory control period. This mainly reflects an increase in the debt risk premium to 3.25 per cent (from 1.425 per cent set by the ESCV).

Jemena's prices are affected by a significant reward under the ESCV's opex efficiency carryover mechanism. Conversely, United Energy's and SP AusNet's prices reflect significant penalties arising under the ESCV's S factor mechanism.

The AER's decision to maintain capex and opex at close to historic levels has resulted in small price impacts across the Victorian DNSPs.

18.5.4 Other factors affecting price calculations

In examining the PTRMs submitted by the Victorian DNSPs with their regulatory proposals, the AER identified that price inputs for 2010 did not align with approved tariff schedules for that year as required by the PTRM. Minor differences arose for all of the DNSPs where certain tariffs were expected to be introduced during the regulatory control period, and adjustments were also made to reflect the recovery of S factor amounts as a price adjustment, rather than a revenue adjustment. These changes were corrected by the DNSPs, noting that S factor amounts would therefore need to be included as a building block component (see section 15.7.12 for discussion).

In converting the Victorian DNSPs' approved forecast capex allowances into the asset categories in the PTRM (including for tax purposes) the AER has applied the same percentage allocations used by the DNSPs in their regulatory proposals.

The AER notes that the price changes calculated in the Victorian DNSPs' proposals (that is, in the form of X factors) reflected the impact of increases in building block revenue requirements but also presumed tariff changes for particular customers (where tariff reassignments affect the expected revenue of the DNSP). The AER requested the Victorian DNSPs remove the impact of assumed tariff reassignments, in particular in relation to the rollout of AMI and the expected introduction of time of use tariffs. The proper functioning of the PTRM requires the assumption that customers face the same tariff structures as per the particular base year (in this case, 2010) such that the approved X factors are assumed to be appropriately passed onto all customers. While it may be the case that tariff reassignments occur and will affect the expected revenues of the DNSP, the AER considers it inappropriate to pre-empt such outcomes and any such revenue impacts are appropriately considered by the DNSP at the time of preparing pricing proposals. That is, the setting of X factors in the AER's PTRM should be revenue neutral to such anticipated changes. This also avoids complex arguments about likely tariff structures which are unnecessary during the building block determination process. Such arguments would take place in the context of the incentive for the Victorian DNSPs to predict customer reassignments to tariffs which can result in revenue shortfalls, only to then have the Victorian DNSPs adjust their prices and tariff structures such that their actual revenue position is improved. The AER's requirements in relation to tariff reassignments are outlined in appendix H of this decision and will be applied during the separate pricing approval process following the AER's final decision in October 2010.

18.6 Summary of decision on building block components

This section provides a summary of the AER's decision for each DNSP with respect to the building block components listed in clause 6.4.3(a).

18.6.1 CitiPower

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of CitiPower's RAB to be $1286.5 million as at 1 January 2011. Based on this opening value, the

AER has modelled CitiPower's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.15.

Table 18.15 AER forecast roll forward of CitiPower's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	1286.5	1378.7	1465.5	1560.9	1628.0
Net capital expenditure[a]	127.3	125.3	137.2	112.8	122.2
Indexation of opening RAB	33.1	35.5	37.7	40.2	41.9
Straight-line depreciation	68.3	73.9	79.6	85.8	91.7
Closing RAB	1378.7	1465.5	1560.9	1628.0	1700.6

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that CitiPower's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to CitiPower's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.25.

The nominal vanilla WACC of 9.68 per cent is based on a post-tax nominal return on debt of 8.90 per cent and a pre-tax nominal return on equity of 10.85 per cent. These figures are calculated using observed market data as at 19 March 2010, and will be updated closer to when the AER make the final decision and the distribution determination.

Depreciation

As discussed in chapter 10, the AER has not approved CitiPower's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance. Table 18.15 above shows the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled CitiPower's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than CitiPower's actual gearing, and a statutory company income tax rate of 30 per cent for 2011 and 2012, reducing to 28 per cent by 2015. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.65 has been applied when calculating the net tax allowance.

Table 18.16 shows the AER's estimate of CitiPower's tax payments.

Table 18.16 AER modelling of CitiPower's net tax allowance ($'m, nominal)

	2011	2012	2013	2014	2015
Tax payable	17.3	18.0	18.8	19.0	19.4
Value of imputation credits	–11.2	–11.7	–12.2	–12.3	–12.6
Net tax allowance	6.0	6.3	6.6	6.6	6.8

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for CitiPower of $199.3 million (nominal) during the forthcoming regulatory control period, which is $51.5 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts arising from the ESCV's S factor and carryover mechanisms is a total of –$26.2 million (nominal), compared to the nil amounts proposed by CitiPower.

18.6.2 Powercor

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of Powercor's RAB to be $2204.9 million as at 1 January 2011. Based on this opening value, the AER has modelled Powercor's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.17.

Table 18.17 AER forecast roll-forward of Powercor's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	2204.9	2347.8	2494.1	2644.5	2800.4
Net capital expenditure[a]	204.8	214.4	225.0	237.4	248.6
Indexation of opening RAB	56.8	60.5	64.2	68.1	72.1
Straight-line depreciation	118.7	128.5	138.8	149.6	161.0
Closing RAB	2347.8	2494.1	2644.5	2800.4	2960.1

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that Powercor's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to Powercor's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.26.

The nominal vanilla WACC of 9.68 per cent is based on a post-tax nominal return on debt of 8.90 per cent and a pre-tax nominal return on equity of 10.85 per cent. These figures are calculated using observed market data as at 19 March 2010, and will be updated closer to when the AER makes the final decision and the distribution determination.

Depreciation

As discussed in chapter 10, the AER has not approved Powercor's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance. Table 18.17 shows the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled Powercor's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Powercor's actual gearing, and a statutory company income tax rate of 30 per cent for 2011 and 2012, reducing to 28 per cent by 2015. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.65 has been applied when calculating the net tax allowance.

Table 18.18 shows the AER's estimate of Powercor's tax payments.

Table 18.18 AER modelling of Powercor's net tax allowance ($'m, nominal)

	2011	2012	2013	2014	2015
Tax payable	22.1	24.5	26.4	28.0	30.3
Value of imputation credits	–14.3	–15.9	–17.1	–18.2	–19.7
Net tax allowance	7.7	8.6	9.2	9.8	10.6

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for Powercor of $672.7 million (nominal) during the forthcoming regulatory control period, which is $276.4 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by Powercor under the ESCV's S factor and carryover mechanisms have been reduced to –$18.0 million (nominal) from the $54.4 million proposed.

18.6.3 Jemena

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of Jemena's RAB to be $742.2 million as at 1 January 2011. Based on this opening value, the AER has modelled Jemena's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.19.

Table 18.19 AER forecast roll-forward of Jemena's regulated asset base ($m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	742.2	775.1	810.5	846.2	881.2
Net capital expenditure[a]	59.8	66.1	70.4	73.9	79.0
Indexation of opening RAB	19.1	20.0	20.9	21.8	22.7
Straight-line depreciation	46.0	50.6	55.5	60.8	55.0
Closing RAB	775.1	810.5	846.2	881.2	927.9

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that Jemena's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to Jemena's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.27.

The nominal vanilla WACC of 9.68 per cent is based on a post-tax nominal return on debt of 8.90 per cent and a pre-tax nominal return on equity of 10.85 per cent. These figures are calculated using observed market data as at 19 March 2010, and will be updated closer to when the AER makes the final decision and the distribution determination.

Depreciation

As discussed in chapter 10, the AER has not approved Jemena's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance. Table 18.19 shows the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled Jemena's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Jemena's actual gearing, and a statutory company income tax rate of 30 per cent for 2011 and 2012, reducing to 28 per cent by 2015. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.65 has been applied when calculating the net tax allowance.

Table 18.20 shows the AER's estimate of Jemena's tax payments.

Table 18.20 AER modelling of Jemena's net tax allowance ($'m, nominal)

	2011	2012	2013	2014	2015
Tax payable	6.6	7.9	9.4	10.6	8.6
Value of imputation credits	–4.3	–5.1	–6.1	–6.9	–5.6
Net tax allowance	2.3	2.8	3.3	3.7	3.0

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for Jemena of $266.5 million (nominal) during the forthcoming regulatory control period, which is $68.8 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by Jemena under the ESCV's S factor and carryover mechanisms have been increased to $57.8 million (nominal) from the $54.1 million proposed.

18.6.4 SP AusNet

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of SP AusNet's RAB to be $2094.2 million as at 1 January 2011. Based on this opening value, the AER has modelled SP AusNet's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.21.

Table 18.21 AER forecast roll-forward of SP AusNet's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	2094.2	2194.0	2344.9	2500.8	2672.8
Net capital expenditure[a]	190.6	198.2	209.7	221.3	239.9
Indexation of opening RAB	53.9	56.5	60.4	64.4	68.8
Straight-line depreciation	144.8	103.8	114.2	113.7	108.9
Closing RAB	2194.0	2344.9	2500.8	2672.8	2872.6

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that SP AusNet's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to SP AusNet's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.28.

The nominal vanilla WACC of 9.68 per cent is based on a post-tax nominal return on debt of 8.90 per cent and a pre-tax nominal return on equity of 10.85 per cent. These figures are calculated using observed market data as at 19 March 2010, and will be updated closer to when the AER makes the final decision and the distribution determination.

Depreciation

As discussed in chapter 10, the AER has not approved SP AusNet's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance. Table 18.21 shows the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled SP AusNet's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than SP AusNet's actual gearing, and a statutory company income tax rate of 30 per cent for 2011 and 2012, reducing to 28 per cent by 2015. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.65 has been applied when calculating the net tax allowance.

Table 18.22 shows the AER's estimate of SP AusNet's tax payments.

Table 18.22 AER modelling of net tax allowance ($'m, nominal)

	2011	2012	2013	2014	2015
Tax payable	23.3	9.9	12.5	12.3	11.0
Value of imputation credits	–15.2	–6.5	–8.1	–8.0	–7.1
Net tax allowance	8.2	3.5	4.4	4.3	3.8

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for SP AusNet of $726.1 million (nominal) during the forthcoming regulatory control period, which is $223.0 million less than proposed.

Revenue decrements arising from previous periods' control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by SP AusNet under the ESCV's S factor and carryover mechanisms have been reduced to –$69.4 million (nominal) from the $0.7 million proposed.

18.6.5 United Energy

Asset base roll forward and indexation

As discussed in chapter 9, the AER has determined the opening value of United Energy's RAB to be $1387.7 million as at 1 January 2011. Based on this opening value, the AER has modelled United Energy's RAB over the forthcoming regulatory control period using the PTRM and as shown in table 18.23.

Table 18.23 AER forecast roll-forward of United Energy's regulated asset base ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	1387.7	1469.6	1543.6	1607.9	1671.5
Net capital expenditure[a]	117.9	116.7	114.5	121.5	126.4
Indexation of opening RAB	35.7	37.8	39.7	41.4	43.0
Straight-line depreciation	71.8	80.5	89.9	99.3	109.2
Closing RAB	1469.6	1543.6	1607.9	1671.5	1731.8

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

Return on capital

The AER considers that United Energy's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding the aforementioned building block components.

The AER has determined the annual return on capital allowance by applying the WACC to United Energy's opening RAB for each year of the forthcoming regulatory control period. This amount is outlined in table 18.29.

The nominal vanilla WACC of 9.68 per cent is based on a post-tax nominal return on debt of 8.90 per cent and a pre-tax nominal return on equity of 10.85 per cent. These figures are calculated using observed market data as at 19 March 2010, and will be updated closer to when the AER makes the final decision and the distribution determination.

Depreciation

As discussed in chapter 10, the AER has not approved United Energy's proposed depreciation schedules.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the forthcoming regulatory control period and to determine the depreciation allowance. Table 18.23 shows the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled United Energy's benchmark income tax liability during the forthcoming regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than

United Energy’s actual gearing, and a statutory company income tax rate of 30 per cent for 2011 and 2012, reducing to 28 per cent by 2015. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.65 has been applied when calculating the net tax allowance.

Table 18.24 shows the AER’s estimate of United Energy’s tax payments.

Table 18.24 AER modelling of United Energy's net tax allowance ($’m, nominal)

	2011	2012	2013	2014	2015
Tax payable	13.6	16.0	19.1	20.7	22.4
Value of imputation credits	–8.8	–10.4	–12.4	–13.4	–14.6
Net tax allowance	4.8	5.6	6.7	7.2	7.8

Source: AER analysis.

Operating and maintenance expenditure

As discussed in chapter 7, the AER has determined a forecast opex allowance for United Energy of $503.0 million (nominal) during the forthcoming regulatory control period, which is $144.1 million less than proposed.

Revenue decrements arising from previous periods’ control mechanisms

As outlined in chapters 13 and 15, the AER has determined that amounts claimed by United Energy under the ESCV’s S factor and carryover mechanisms have been reduced to –$111.8 million (nominal) from the $12.5 million proposed.

18.7 AER conclusion

In accordance with clause 6.12.1 (2) of the NER, the AER's decision on the annual revenue requirement for each Victorian DNSP is set out below. The AER’s decision on the annual revenue requirement for each Victorian DNSP is also set out in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

The AER has calculated each DNSP’s revenue requirements and X factors based on its decisions regarding the aforementioned building block components. These calculations are summarised in the following sections.

CitiPower

The AER’s draft decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $1127.5 million, compared to $1424.8 million proposed by CitiPower. The main reasons for this difference reflect:

- a reduction of $201.1 million from the return on capital, reflecting a lower WACC and capex
- the removal of $51.5 million from the proposed opex allowance.

Table 18.25 AER conclusion on CitiPower’s revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		124.5	133.8	142.6	152.0	158.6
Regulatory depreciation		35.2	38.4	41.9	45.6	49.6
Operating expenditure		36.7	37.7	39.5	42.0	43.4
Efficiency carryover amounts		5.6	–7.2	–4.9	–5.2	0.0
S factor amounts		0.2	–3.0	–3.6	–0.2	–7.8
Tax allowance		6.0	6.3	6.6	6.6	6.8
Annual revenue requirements		208.2	206.0	222.0	240.8	250.6
Expected revenues	211.8	205.0	215.1	223.2	234.7	248.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		7.27	0.00	0.00	–2.00	–2.00

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

CitiPower's building block revenue requirements increase over the forthcoming regulatory control period, in spite of penalties in the form of carryover amounts. The AER has considered the increase in underlying revenue requirements when setting X factors, and has determined that price increases spread over 2014 and 2015 are necessary to minimise the variance between the expected and required revenues in 2015. When taking into account the fact that revenue requirements in 2015 reflect –7.8 million (nominal) million of amounts relating to S factor penalties, this difference is –3.90 per cent.

Powercor

The AER’s draft decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $2284.6 million, compared to $2977.3 million proposed by Powercor. The main reasons for this difference reflect:

- a reduction of $283.2 million to the return on capital, reflecting a lower WACC and capex
- the removal of $276.4 million from the proposed opex allowance
- –$18.0 million in carryover amounts, compared to the $54.4 million proposed

Table 18.26 AER conclusion on Powercor's revenue requirements and X factors ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		213.4	227.2	241.4	255.9	271.0
Regulatory depreciation		62.0	68.1	74.6	81.5	88.9
Operating expenditure		123.0	127.5	133.1	141.9	147.2
Efficiency carryover amounts		0.0	16.4	0.3	–6.8	0.0
S factor amounts		16.7	–8.0	–4.8	0.9	–32.6
Tax allowance		7.7	8.6	9.2	9.8	10.6
Annual revenue requirements		422.7	439.8	453.8	483.3	485.0
Expected revenues	426.7	413.1	434.8	458.3	481.3	502.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		8.14	0.00	0.00	0.00	0.00

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

The AER considers these X factors minimise the variance between the expected and required revenues in the final year to 3.48 per cent. In the absence of –$32 million of carryover amounts in 2015, this difference would still only be –2.94 per cent.

Jemena

The AER's draft decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $895.3 million, compared to $1142.0 million proposed by Jemena. The main reasons for this difference reflect:

- a reduction of $129.0 million to the return on capital, reflecting a lower WACC and capex
- the removal of $68.8 million from the proposed opex allowance
- the removal of $34.7 million from the tax allowance, reflecting a gamma of 0.65 compared to the 0.2 proposed.

Table 18.27 AER conclusion on Jemena’s revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		71.8	75.0	78.4	81.9	85.3
Regulatory depreciation		26.9	30.7	34.7	39.0	32.3
Operating expenditure		48.9	50.4	52.2	57.0	57.9
Efficiency carryover amounts		21.0	15.3	18.7	2.8	0.0
S factor amounts		–2.2	0.3	0.8	0.8	0.4
Tax allowance		2.3	2.8	3.3	3.7	3.0
Annual revenue requirements		168.7	174.4	188.1	185.2	178.9
Expected revenues	166.0	165.9	174.7	184.2	187.7	184.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		1.46	0.00	0.00	3.00	6.00

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

The AER notes that Jemena's building block requirements decline from 2013, hence in order to minimise the variance with expected revenues in 2015 requires average prices to also decline. Rather than applying a single large price reduction in 2015, the AER has attempted to smooth the required changes over 2014 and 2015. The AER considers these X factors minimise the variance between the expected and required revenues in the final year to 3.03 per cent.

SP AusNet

The AER’s draft decision results in a total nominal revenue requirement over the forthcoming regulatory control period of $2104.8 million, compared to $2750.1 million proposed by SP AusNet. The main reasons for this difference reflect:

- a reduction of $244.5 million to the return on capital, reflecting a lower WACC and capex
- the removal of $223.0 million from the proposed opex allowance
- carryover amounts of –$69.4 million, compared to the $0.7 million proposed, reflecting ECM and also S factor penalties.

Table 18.28 AER conclusion on SP AusNet’s revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Regulatory depreciation		202.7	212.3	226.9	242.0	258.6
Return on capital		90.9	47.3	53.8	49.3	40.1
Operating expenditure		133.7	138.5	144.6	151.6	157.7
Efficiency carryover amounts		–3.7	–24.6	–9.9	3.6	0.0
S factor amounts		20.5	2.5	–5.5	0.9	–53.1
Tax allowance		8.2	3.5	4.4	4.3	3.8
Annual revenue requirements		452.2	379.4	414.2	451.7	407.1
Expected revenues	379.5	382.2	400.1	422.1	448.7	475.1
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		4.46	0.00	0.00	0.00	0.00

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

SP AusNet's building block requirements are affected by significant S factor penalties, reaching a maximum of –$53.1 million (nominal) in 2015. The AER considers that it would not be appropriate to align expected revenues taking these amounts into account, as doing so is likely to create an unnecessary price shock in 2016 when the underlying building blocks are reassessed. In the absence of the S factor penalty, the difference between expected revenues and building block revenue requirements in 2015 is minimised at 3.23 per cent, compared to the 16.71 per cent if the penalty is regarded.

United Energy

The AER’s draft decision results in a total revenue requirement over the forthcoming regulatory control period of $1419.4 million, compared to $1926.1 million proposed by United Energy. The main reasons for this difference reflect:

- a reduction of $160.3 million to the return on capital, reflecting a lower WACC and capex
- the removal of $124.3 million from the proposed opex allowance
- carryover amounts of –$111.8 million, compared to the $12.5 million proposed, reflecting S factor penalties.

Table 18.29 AER conclusion on United Energy’s revenue requirements and X factors ($’m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		134.3	142.2	149.4	155.6	161.8
Regulatory depreciation		36.0	42.7	50.2	57.9	66.2
Operating expenditure		92.9	95.8	99.7	105.6	108.9
Efficiency carryover amounts		0.0	0.0	0.0	0.0	0.0
S factor amounts		–5.1	–19.8	–19.2	–20.1	–47.6
Tax allowance		4.8	5.6	6.7	7.2	7.8
Annual revenue requirements		262.9	266.6	286.8	306.2	297.0
Expected revenues	296.2	249.5	262.1	281.0	303.5	332.2
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		19.57	0.00	–2.00	–3.00	–5.00

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

United Energy's building block requirements are affected by significant S factor penalties, reaching a maximum of –$47.6 million (nominal) in 2015. As noted above for SP AusNet, the AER considers that it would not be appropriate to align expected revenues taking these amounts into account.

In the absence of these penalties, United Energy's building block requirements steadily increase over the forthcoming regulatory control period. Hence after an initial price reduction in 2011, the AER considers that setting X factors that produce gradual price increases towards the end of the period appropriately minimise the variance between the expected and required revenues in 2015. In the absence of the S factor penalty, this difference is 3.63 per cent, compared to the 11.83 per cent if the penalty is regarded.

In accordance with clause 6.3.2(a) of the NER the AER has decided that the annual revenue requirements for each year of the regulatory control period for each Victorian DNSP are as follows:

Table 18.30 AER conclusion on the annual revenue requirements ($'m, nominal)

	2011	2012	2013	2014	2015
CitiPower	208.2	206.0	222.0	240.8	250.6
Powercor	422.7	439.8	453.8	483.3	485.0
Jemena	168.7	174.4	188.1	185.2	178.9
SP AusNet	452.2	379.4	414.2	451.7	407.1
United Energy	262.9	266.6	286.8	306.2	297.0

In accordance with clause 6.5.9 of the NER the AER has decided that the X factors for each year of the regulatory control period for each Victorian DNSP as follows:

Table 18.31 AER conclusion on X factors (per cent)

	2011	2012	2013	2014	2015
CitiPower	7.27	0.00	0.00	–2.00	–2.00
Powercor	8.14	0.00	0.00	0.00	0.00
Jemena	1.46	0.00	0.00	3.00	6.00
SP AusNet	4.46	0.00	0.00	0.00	0.00
United Energy	19.57	0.00	–2.00	–3.00	–5.00

19 Public lighting

19.1 Introduction and background

This chapter sets out the AER's considerations of the Victorian distribution network service providers' (DNSPs') control mechanism for public lighting services and how compliance with that mechanism is to be demonstrated by the Victorian DNSPs in the forthcoming regulatory control period.

Classification of the Victorian DNSPs' public lighting services is set out in chapter 2 of this draft decision.

In August 2004, the Essential Services Commission of Victoria (ESCV) published a Review of Public Lighting Excluded Service Charges—Final Decision, which determined public lighting charges to apply from October 2004 ('2004 decision') and the basis for adjusting these charges annually for a return on and return of capital.

Further to this, the AER published a final decision on Energy Efficient Public Lighting Charges in February 2009 ('2009 final decision'). The 2009 final decision related to the operation, maintenance and repair (OMR) charges for T5 (energy efficient) public lighting. It also included Mercury Vapour 80 (MV80) luminaires' written down value and avoided costs payable by municipal councils to DNSPs for the period to 31 December 2010, where those MV80 assets are removed from service and replaced with T5 energy efficient lighting.[1]

The costs associated with public lighting services are ultimately passed onto ratepayers through annual municipal council rates.

19.2 Regulatory requirements

Clause 6.2.2(a) of the National Electricity Rules (NER) separates direct control services into standard control services and alternative control services.

Clause 6.2.5(d) of the NER outlines the factors the AER must have regard to in deciding on the control mechanism to apply to alternative control services. One option the AER may apply is a cap on the prices of individual services under clause 6.2.5(d)(2) of the NER.

Clause 6.8.1 of the NER requires the AER to publish a framework and approach paper prior to every distribution determination, which includes the control mechanisms to be applied to alternative control services.

Clauses 6.12.1(12) and 6.12.1(13) of the NER require the AER's distribution determination to provide a decision on the control mechanism for alternative control services and how compliance with that control mechanism is to be demonstrated.

Clause 6.12.3(c) of the NER provides that the control mechanism to be applied in a distribution determination must be as set out in the AER's Framework and approach paper.

[1] AER, *Energy Efficient Public Lighting Charges—Victoria (Final)*, February 2009.

19.3 AER Framework and approach

In its Framework and approach paper for the 2011–15 Victorian electricity distribution determination, published in May 2009,[2] the AER determined that a price cap control mechanism would apply to the Victorian DNSPs' public lighting services. The Framework and approach also stated that:

- Services regarding the operation, repair, replacement and maintenance of DNSP public lighting assets would be classified as alternative control services
- The AER would apply a price cap to public lighting OMR services through the application of a limited building block approach
- A CPI-X approach would be used to establish a price path for these services.

The AER notes that its assessment of Victorian DNSPs' proposals for alternative control services, which includes public lighting charges, is based on its Framework and approach paper.[3] It is also noted that ESCV's Electricity Industry Guideline No.14[4] (Guideline 14) was used previously by the ESCV and the AER in assessments of public lighting charges for the current regulatory control period. Charges for public lighting services in the forthcoming regulatory control period, 2011–15, are assessed and regulated by the AER under the NER.

In August 2009, the AER determined that the approach to regulating public lighting in Victoria for 2011–15 would involve charges based on forecast capital expenditure (capex) rather than on actual capex.[5] This was a departure from the ESCV's approach to public lighting reviews since 2004, as well as the AER's previous approach in its 2009 final decision.[6]

Consistent with its Framework and approach paper, the AER implemented a limited building block approach for public lighting charges for the forthcoming regulatory control period.

Victorian DNSPs provided their forecast cost inputs consistent with this approach. These were multiplied by the forecast number of public lights to obtain the forecast operating and capital expenditure requirements for the forthcoming regulatory control period.

The AER also notes that due to the transition from an actual capex to a forecast capex model, there are two years (2009 and 2010) worth of regulated return on investment, and depreciation that the DNSPs will be entitled to recover in the forthcoming regulatory control period.

2 AER, *Framework and approach paper for Victorian electricity distribution regulatory, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1January 2011*, May 2009, p. 79
3 ibid., pp. 44–50.
4 ESCV, *Electricity Industry Guideline No.14—Provision of services by electricity distributors: Issue 1*, April 2004.
5 AER, *Framework and approach paper*, May 2009, p. 3.
6 Public lighting charges for 2010 were approved by the AER in December 2009, based on the existing methodology of actual capex rolled into the DNSPs' respective public lighting regulatory asset bases. The AER adopted a forecast capex approach to public lighting for the 2011-15 regulatory control period to be consistent with the approach adopted for standard control services.

A mechanism in the 2011–15 model permits this recovery in a manner that enables the Victorian DNSPs to smooth the resultant price adjustment over the forthcoming regulatory control period. This acts in the same manner as the X-factor that applies to the building block determination for standard control services.

The AER provided DNSPs with the updated public lighting model in November 2009 following consultation with them in September 2009. The Victorian DNSPs' 2011–15 regulatory proposals have adopted the AER's updated model.

The authority of the AER, and previously the ESCV, to decide whether a term or condition for public lighting services is fair and reasonable, is provided under a DNSP's distribution licence, which also stipulates that the terms and conditions for providing public lighting services must be consistent with the *Public Lighting Code 2005 (Victoria)* (the Code). Importantly, the Code only extends to the provision by DNSPs of the ongoing operation, maintenance and replacement of public lighting assets that they own (clause 1.3).

The explanatory note in clause 3 of the Code states that the DNSP and the public lighting customer may agree that after the construction and commissioning of the assets, ownership of the assets will transfer to the DNSP. Where such an agreement is made, the assets become subject to the applicable provisions of the Code. If no agreement is reached, asset ownership remains with the public lighting customer and are not subject to regulation under the Code.

19.4 Summary of Victorian DNSP regulatory proposals

The following sections outline the Victorian DNSPs' proposed public lighting charges for the main light types, including MV80, Sodium-High Pressure (SHP) 150, SHP 250, and T5 luminaires, together with forecast total capex and opex for the forthcoming regulatory period. Graphs showing the proposed annual price increases for the main light types are also provided.

19.4.1 CitiPower

Current and proposed public lighting charges

In its regulatory proposal, CitiPower noted that its current public lighting OMR charges were previously determined in the ESCV's 2004 decision and updated by the AER's 2009 final decision for energy efficient public lighting charges.

CitiPower's current and proposed charges are shown in table 19.1.

Table 19.1 CitiPower, current and proposed public lighting charges, main light types ($, nominal)

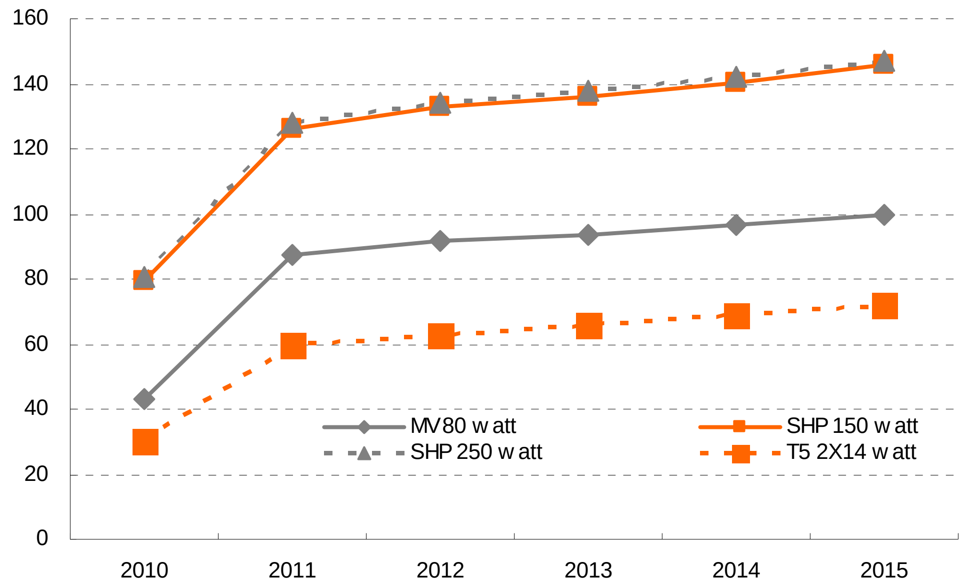
	Current	Proposed				
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	43.33	87.48	91.76	93.55	96.34	99.52
Sodium high pressure 150 watt	79.64	126.44	132.64	135.99	140.56	145.61
Sodium high pressure 250 watt	80.85	128.13	134.41	137.71	142.28	147.35
T5 2x14 watt	30.35	59.48	62.48	65.59	68.85	72.19

Note: CitiPower's prices for all public light types are provided in table O.1 of appendix O.

Source: CitiPower, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Figure 19.1 shows the profile of CitiPower's proposed charges for the major light types for the forthcoming regulatory control period.

Figure 19.1 CitiPower, current and proposed charges, main light types ($, nominal)



Source: CitiPower, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

CitiPower proposed to continue its practice of differentiating charges to customers for public lighting services based on:

- the type of public lighting—different charges apply to fluorescent, mercury vapour, sodium low/high pressure, incandescent and metal halide lights
- the wattage of the lighting—more than one wattage level applies to each of the five lighting types.

CitiPower noted that these charges reflect the different costs of providing different public lighting types and wattages.[7]

Current and forecast capital expenditure

CitiPower's public lighting model provided actual capex for the current regulatory control period and forecast capex for the forthcoming regulatory control period (tables 19.2 and 19.3).

Table 19.2 CitiPower, capex, current regulatory control period ($, 2010)

Capex (net of customer contributions)	Actual				Forecast
	2006	**2007**	**2008**	**2009**	**2010**
Poles and brackets	344 628	233 246	245 778	538 172	310 100
Existing lights (luminaires)	1 378 513	932 985	983 110	2 152 688	1 240 399
Energy efficient lights (luminaires and ballasts)	–	–	–	–	–
Total net capex	**1 723 142**	**1 166 231**	**1 228 888**	**2 690 859**	**1 550 499**

Source: CitiPower, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Table 19.3 CitiPower, forecast capex, forthcoming regulatory control period ($, 2010)

Capex (net of customer contributions)	Forecast				
	2011	**2012**	**2013**	**2014**	**2015**
Poles and brackets	188 489	193 084	196 754	200 108	203 534
Existing lights (luminaires)	–832 670	–742 980	–80 324	18 738	19 099
Energy efficient lights (luminaires and ballasts)	–	–	–	–	–
Total net capex	**–644 181**	**–549 896**	**116 429**	**218 846**	**222 634**

Note: Negative capex figures are due to customer contributions for replacing existing lights (MV80) with energy efficient lights (T5), being greater than the capex for existing lights.
Source: CitiPower, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

CitiPower's model indicated that energy efficient T5 lights would be installed from 2010. The forecast negative capex from 2011 to 2013 accounts for customer (council) contributions paid to CitiPower for the written down value of MV80 luminaires

7 CitiPower, *Regulatory Proposal 2011 to 2015*, 30 November 2009, p. 367.

removed from service and which are replaced with T5 luminaires. Note however that the initial capital installation costs of the T5s will also be funded by customer (council) contributions, not by CitiPower.

During 2011–15, costs associated with the installation of poles and brackets and replacement of T5 lights (due to damage or defects) are included in CitiPower's forecast capex requirements. This capex is recovered through OMR charges.

Current and proposed operating and maintenance expenditure

CitiPower's public lighting model provided actual and forecast opex for the current and forthcoming regulatory control periods, respectively (tables 19.4 and 19.5).

Table 19.4 CitiPower, opex, current regulatory control period ($, 2010)

	Actual				Forecast
	2006	**2007**	**2008**	**2009**	**2010**
Total opex	4 934 422	4 774 630	5 423 529	4 927 903	5 038 813

Source: CitiPower, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Table 19.5 CitiPower, forecast opex, forthcoming regulatory control period ($, 2010)

	Forecast				
	2011	**2012**	**2013**	**2014**	**2015**
Total opex	3 266 090	3 386 943	3 482 976	3 574 638	3 666 380

Source: CitiPower, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Limited building block approach

CitiPower stated that its methodology for developing proposed public lighting charges involves applying a limited building block approach, as reflected in the AER's public lighting model.

In applying this approach, CitiPower made various adjustments to several cost inputs. This included changes to the standard working hours per day, the proportion of T5 failures between bulk changes, the unit costs of T5 luminaires, dedicated street lighting poles and patrol and traffic control costs.

CitiPower also noted that its proposed labour and materials costs and associated escalation rates are consistent with those proposed for standard control services. An adjustment for CPI was also applied.[8]

[8] CitiPower, *Regulatory Proposal 2011–15*, November 2009, pp. 364–365.

19.4.2 Powercor

Current and proposed public lighting charges

Powercor's proposal noted that its current public lighting OMR charges were determined in the ESCV's 2004 decision and updated by the AER's 2009 final decision for energy efficient public lighting charges.

Powercor's current and proposed charges are shown in table 19.6.

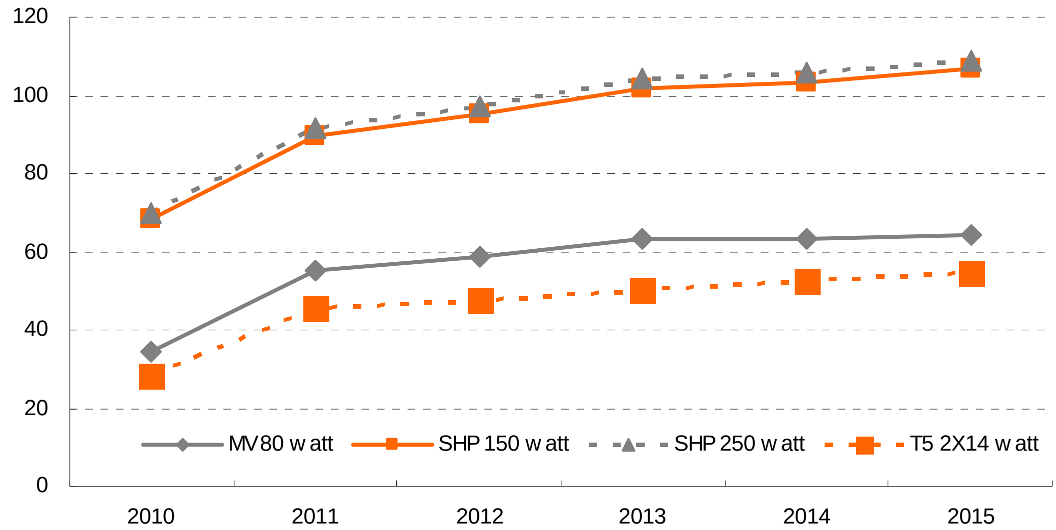
Table 19.6 Powercor, current and proposed public lighting charges, main light types ($, nominal)

	Current		Proposed			
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	34.56	55.07	58.75	63.38	63.23	64.44
Sodium high pressure 150 watt	68.31	89.85	95.29	101.78	103.49	106.62
Sodium high pressure 250 watt	69.67	91.83	97.45	104.21	105.75	108.83
T5 2x14 watt	28.52	45.49	47.80	50.16	52.46	54.80

Note: Powercor's prices of all light types are provided in table O.2 of appendix O.
Source: Powercor, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Figure 19.2 shows the profile of Powercor's proposed charges for the major light types for the forthcoming regulatory control period.

Figure 19.2 Powercor, current and proposed charges, main light types ($, nominal)



Source: Powercor, *Regulatory Proposal 2011–15*—public lighting model, November 2009 (updated in March 2010).

Powercor proposed to continue its practice of differentiating charges to customers for public lighting services based on:

- the type of public lighting—different charges apply to fluorescent, mercury vapour, sodium low/high pressure, incandescent and metal halide lights
- the wattage of the lighting—more than one wattage level applies to each of the five lighting types.

Powercor noted that these charges reflect the different costs of providing each of these public lighting types and wattages.[9]

Current and forecast capital expenditure

Powercor's public lighting model provided actual capex for the current regulatory control period and forecast capex for the forthcoming regulatory control period (tables 19.7 and 19.8).

Powercor's model indicated that energy efficient T5 lights would be installed from 2010. The forecast negative capex from 2011 to 2013 accounts for customer (council) contributions paid to Powercor for the written down value of MV80 luminaires removed from service and which are replaced with T5 luminaires. Note however that the initial capital installation costs of the T5s will also be funded by customer (council) contributions, not by Powercor.

Table 19.7 Powercor, capex, current regulatory control period ($, 2010)

Capex (net of customer contributions)	Actual				Forecast
	2006	2007	2008	2009	2010
Poles and brackets	193 136	75 800	193 901	219 204	238 095
Existing lights (luminaries)	772 544	303 198	775 603	876 817	952 378
Energy efficient lights (luminaires and ballasts)	–	–	–	–	–
Total net capex	**965 680**	**378 998**	**969 503**	**1 096 021**	**1 190 473**

Source: Powercor, *Regulatory Proposal 2011–15*—public lighting model, November 2009 (updated in March 2010).

9 Powercor, *Regulatory Proposal 2011–15*, 30 November 2009, p. 375.

Table 19.8 Powercor, forecast capex, forthcoming regulatory control period ($, 2010)

Capex (net of customer contributions)	Forecast				
	2011	2012	2013	2014	2015
Poles and brackets	500 501	494 172	503 579	512 183	520 968
Existing lights (luminaries)[a]	–1 610 933	–1 273 022	–732 357	52 681	53 711
Energy efficient lights (luminaires and ballasts)	–	–	–	–	–
Total net capex	**–1 110 431**	**–778 850**	**–228 778**	**564 864**	**574 680**

Note: Negative capex figures are due to customer contributions for replacing existing lights (MV80) with energy efficient lights (T5), being greater than the capex for existing lights.
Source: Powercor, *Regulatory Proposal 2011–15*—public lighting model, November 2009 (updated in March 2010).

During the forthcoming regulatory control period, costs associated with the installation of poles, brackets and replacement of T5 lights form part of Powercor's forecast capex requirements. This capex will be recovered through OMR charges.

Current and proposed operating and maintenance expenditure

Powercor's public lighting model provided actual and forecast opex for the current and forthcoming regulatory control periods, respectively (tables 19.9 and 19.10).[10]

Table 19.9 Powercor, opex, current regulatory control period ($, 2010)

	Actual				Forecast
	2006	2007	2008	2009	2010
Total opex	6 034 406	7 026 812	8 567 391	8 406 060	9 603 641

Source: Powercor, *Regulatory Proposal 2011–15—public lighting model*, November 2009 (updated in March 2010).

Table 19.10 Powercor, forecast opex, forthcoming regulatory control period ($, 2010)

	Forecast				
	2011	2012	2013	2014	2015
Total opex	6 484 218	6 971 821	7 457 866	7 943 482	8 457 290

Source: Powercor, *Regulatory Proposal 2011–15—public lighting model*, November 2009 (updated in March 2010).

[10] Powercor, *Regulatory Proposal 2011–15—public lighting model*, November 2009

Limited building block approach

Powercor stated that its methodology for developing proposed public lighting charges involves applying a limited building block approach, as reflected in the AER's public lighting model.

In applying this approach, Powercor made various adjustments to several cost inputs. This included changes to the standard working hours per day, the proportion of T5 failures between bulk changes, the unit costs of T5 luminaires, dedicated street lighting poles and patrol and traffic control costs.

Powercor also noted that its proposed labour and materials costs and associated escalation rates are consistent with those used for standard control services. An adjustment for CPI was also applied.[11]

19.4.3 Jemena

Current and proposed public lighting charges

Jemena's initial public lighting proposal was based on an earlier draft of the AER's 2011–15 public lighting model, where Jemena stated that it reserved the right to propose a different model to the AER at a later date.[12] Subsequent to this, and at the AER's request, Jemena resubmitted its proposed public lighting charges on the basis of the AER's November 2009 model consistent with the approach adopted by the other DNSPs.[13]

Jemena's current prices and proposed prices for the forthcoming regulatory control period are provided in table 19.11.

Table 19.11 Jemena, current and proposed public lighting charges, main light types ($, nominal)

	Current	Proposed				
Lighting Service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	32.02	42.50	43.57	46.21	47.43	49.61
Sodium high pressure 150 watt	61.97	79.26	81.69	86.05	88.82	92.72
Sodium high pressure 250 watt	64.17	80.92	83.39	87.88	90.69	94.67
T5 2x14 watt	26.07	28.61	29.57	30.92	32.20	33.66

Note: Jemena's prices for all light types are provided in table O.3 of appendix O. Jemena's submission had 2010 charges including GST but the charges in table 19.11 are excluding GST.

Source: Jemena, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

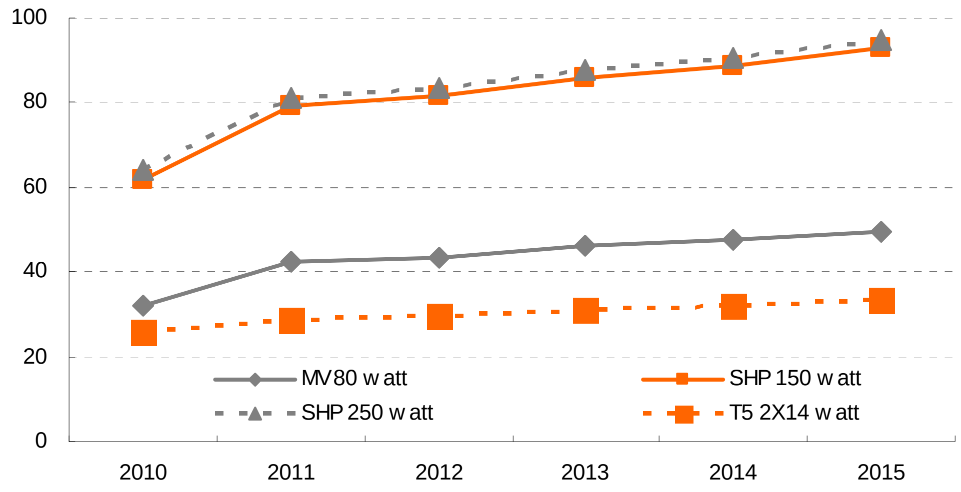
Figure 19.3 shows the profile of Jemena's proposed charges for the main light types for the forthcoming regulatory control period.

11 Powercor, *Regulatory Proposal 2011–15—public lighting model,* November 2009, pp. 364–365.

12 Jemena, *Regulatory Proposal 2011–15,* November 2009, p. 247.

13 Email from Jemena to AER staff on 4 March 2010.

Figure 19.3 Jemena, current and proposed charges, main light types ($, nominal)



Source: Jemena, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Current and forecast capital expenditure

Jemena's public lighting model provided actual capex for the current regulatory control period and forecast capex for the forthcoming regulatory control period (tables 19.12 and 19.13).

Table 19.12 Jemena, capex, current regulatory control period ($, 2010)

Capex (net of customer contributions)	Actual				Forecast
	2006	2007	2008	2009	2010
Poles and brackets	145 891	27 369	30 968	20 115	17 245
Existing lights (luminaries)	463 004	343 481	982 367	650 377	557 593
Energy efficient lights (luminaires and ballasts)	–	–	–	–	–
Total net capex	608 896	370 850	1013 335	670 491	574 838

Source: Jemena, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Table 19.13 Jemena, forecast capex, forthcoming regulatory control period ($, 2010)

Capex (net of customer contributions)	Forecast				
	2011	2012	2013	2014	2015
Poles and brackets	79 483	108 054	140 187	155 808	211 634
Existing lights (luminaries)	937 488	308 485	558 930	272 845	600 370
Energy efficient lights (luminaires and ballasts)	–	4 646	8 888	13 741	18 679
Total net capex	1 016 971	421 185	708 006	442 394	830 683

Source: Jemena, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Jemena's model indicated that energy efficient T5 lights would be installed from 2011, and that these would be the only type of energy efficient lights to be installed during the forthcoming regulatory control period.

The initial capital installation costs of the T5s will be fully funded by customer (council) contributions, rather than by Jemena. During the forthcoming regulatory control period, the costs associated with the installation of poles and brackets and replacement of T5 lights form part of Jemena's forecast capex requirements. This capex will be recovered through OMR charges.

Current and proposed operating and maintenance expenditure

Jemena's public lighting model provided actual and forecast opex for the current and forthcoming regulatory control periods, respectively (tables 19.14 and 19.15).

Table 19.14 Jemena, opex, current regulatory control period ($, 2010)

	Actual				Forecast
	2006	2007	2008	2009	2010
Total opex	2 059 909	1 761 268	1 957 078	1 864 220	1 931 452

Source: Jemena, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Table 19.15 Jemena, forecast opex, forthcoming regulatory control period ($, 2010)

	Forecast				
	2011	2012	2013	2014	2015
Total opex	2 030 491	2 090 563	2 152 888	2 216 105	2 277 286

Source: Jemena, Regulatory Proposal 2011–15—public lighting model, November 2009 (updated in March 2010).

Limited building block approach

As noted previously, Jemena's public lighting model resubmitted to the AER on 24 February 2010 is based on the limited building block approach as set out in the AER's Framework and approach paper.[14] This superseded the model Jemena initially submitted to the AER on 30 November 2009.

19.4.4 SP AusNet

Current and proposed public lighting charges

As part of its regulatory proposal, SP AusNet submitted a public lighting model consistent with the AER model provided in November 2009. SP AusNet's current and proposed charges for the forthcoming regulatory control period, for the central region and north and east regions are provided in tables 19.16 and 19.17 respectively.

Table 19.16 SP AusNet, current and proposed public lighting charges, main light types, central region ($, nominal)

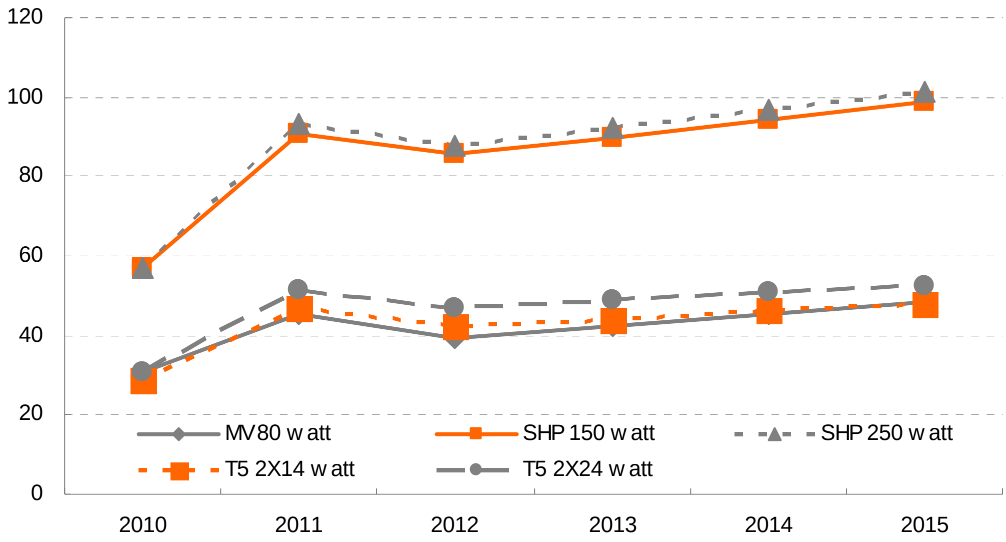
	Current	Proposed				
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	30.78	45.41	39.44	42.52	45.55	48.55
Sodium high pressure 150 watt	57.01	90.83	85.49	89.95	94.29	98.62
Sodium high pressure 250 watt	57.07	93.15	87.80	92.35	96.76	101.17
T5 2X14 watt	28.74	46.91	42.45	44.10	46.43	47.82
T5 2X24 watt	30.90	51.35	46.93	48.67	51.12	52.54

Note: SP AusNet's prices for all public light types are provided in table O.4 and table O.5 of appendix O.
Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

Figure 19.4 shows the profile of SP AusNet's proposed charges for the main light types in the central part of its network.

[14] AER, Framework and approach paper, May 2009, p. 79.

Figure 19.4 SP AusNet, current and proposed charges, main light types, central region



Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

Table 19.17 SP AusNet, current and proposed public lighting charges, main light types, north and east regions ($, nominal)

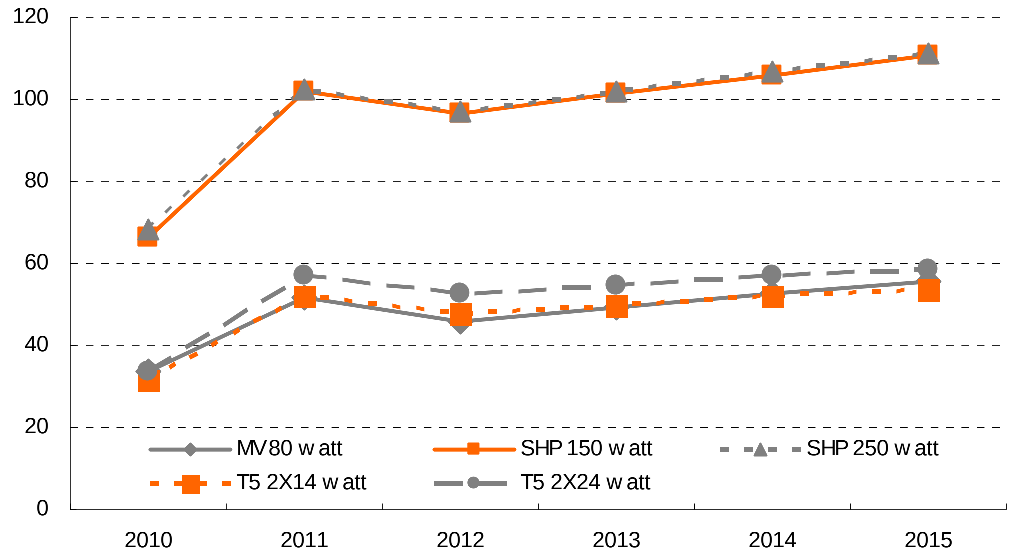
	Current		Proposed			
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	33.53	51.91	45.87	49.24	52.51	55.75
Sodium high pressure 150 watt	66.32	101.82	96.54	101.39	106.07	110.76
Sodium high pressure 250 watt	68.38	102.35	97.05	101.92	106.63	111.33
T5 2X14 watt	31.48	52.34	48.02	49.79	52.25	53.78
T5 2X24 watt	33.69	56.84	52.55	54.42	57.00	58.55

Note: SP AusNet's prices for all public light types are provided in table O.6 of appendix O.

Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

Figure 19.5 shows the profile of SP AusNet's proposed charges for the main light types in the north and east region of its network.

Figure 19.5 SP AusNet, current and proposed charges, main light types, north and east regions, ($, nominal)



Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

Current and forecast capital expenditure

SP AusNet's public lighting model provided the actual capex for the current regulatory control period and forecast capex for the forthcoming regulatory control period (tables 19.18 and 19.19).

Table 19.18 SP AusNet, capex, current regulatory control period ($, 2010)

Capex (net of customer contributions)	Actual				Forecast
	2006	2007	2008	2009	2010
Poles & brackets	764 309	370 827	874 144	563 634	563 627
Existing lights (luminaries)	362 317	175 861	414 553	267 245	267 242
Energy efficient lights (luminaires and ballasts)	–	–	–	–	741 998
Total net capex	1 126 626	546 688	1 288 697	830 879	1 572 867

Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

Table 19.19 SP AusNet, forecast capex, forthcoming regulatory control period ($, 2010)

Capex (net of customer contributions)	Forecast				
	2011	2012	2013	2014	2015
Poles and brackets	1 621 550	1 643 988	1 733 380	1 759 545	1 786 117
Existing lights (luminaries)	763 834	784 686	972 025	978 317	984 708
Energy efficient lights (luminaires and ballasts)	971 407	986 548	588 024	–	–
Total net capex	3 356 791	3 415 223	3 293 429	2 737 862	2 770 825

Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

SP AusNet indicated that some energy efficient T5 lights had already been installed in 2009, with this roll out continuing during the forthcoming regulatory control period.

Current and proposed operating and maintenance expenditure

SP AusNet's public lighting model provided actual and forecast opex for the current and forthcoming regulatory control periods, respectively (tables 19.20 and 19.21).

Table 19.20 SP AusNet, opex, current regulatory control period ($, 2010)

	Actual				Forecast
	2006	2007	2008	2009	2010
Total opex	1 732 327	2 829 397	2 126 267	1 863 625	1 863 602

Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

Table 19.21 SP AusNet, forecast opex, forthcoming regulatory control period ($, 2010)

	Forecast				
	2011	2012	2013	2014	2015
Total opex	4 176 583	4 332 594	4 558 150	4 628 795	4 700 541

Source: SP AusNet, *EDPR 2011–2015—public lighting model*, November 2009 (updated in March 2010).

Limited building block approach

In its proposal, SP AusNet applied a limited building block approach to public lighting charges, consistent with the AER's Framework and approach paper and the AER's November 2009 public lighting model. One significant exception was that SP AusNet proposed to fund a portion of the T5 energy efficient lights to be rolled out over the forthcoming regulatory control period. This funding was included in the model submitted to the AER for approval.

19.4.5 United Energy

Current and proposed public lighting charges

In its regulatory proposal, United Energy's public lighting model was consistent with the AER model provided in November 2009.[15] United Energy's current and proposed charges for the forthcoming regulatory control period are set out in table 19.22.

Table 19.22 United Energy, current and proposed public lighting charges, main light types ($, nominal)

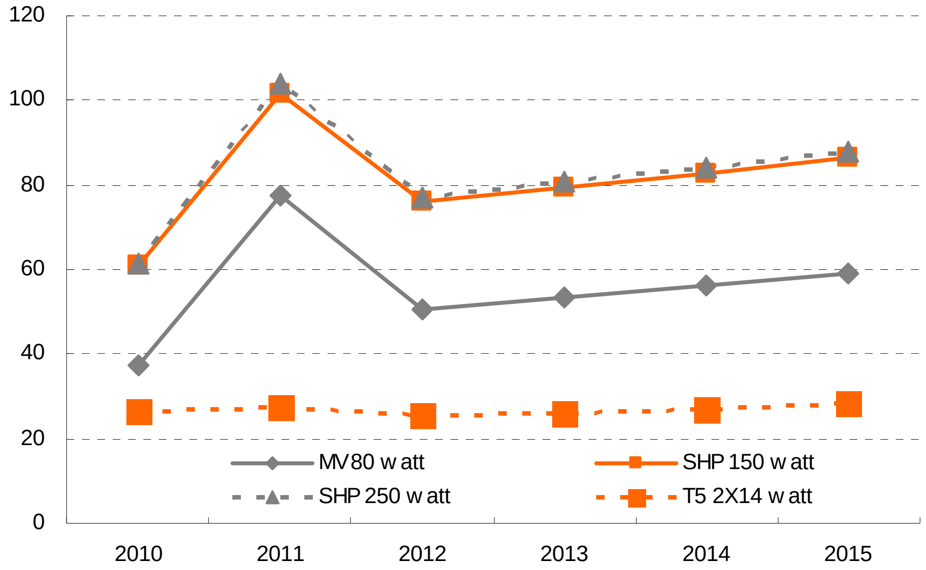
	Current		Proposed			
Lighting service	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Mercury vapour 80 watt	37.47	77.40	50.74	53.59	56.29	59.21
Sodium high pressure 150 watt	60.94	101.65	76.03	79.47	82.78	86.34
Sodium high pressure 250 watt	61.38	104.05	77.22	80.77	84.16	87.80
T5 2x14W watt	26.56	27.60	25.28	25.94	26.84	28.21

Note: United Energy's prices for all public light types are provided in table O.6 of appendix O.

Source: United Energy, Regulatory Proposal 2011–2015—public lighting model, November 2009.

Figure 19.6 shows the profile of United Energy's proposed charges for the major light types for the forthcoming regulatory control period.

Figure 19.6 United Energy, current and proposed charges main light types ($, nominal)



Source: United Energy, Regulatory Proposal 2011–2015—public lighting model, November 2009.

15 United Energy, *Regulatory Proposal 2011–2015*, November 2009, p. 204.

Current and forecast capital expenditure

United Energy's public lighting model provided actual capex for the current regulatory control period and forecast capex for the forthcoming regulatory control period (tables 19.23 and 19.24).

Table 19.23 United Energy, capex, current regulatory control period ($, 2010)

Capex (net of customer contributions)	Actual				Forecast
	2006	**2007**	**2008**	**2009**	**2010**
Poles and brackets	371 144	168 068	121 953	260 003	256 765
Existing lights (luminaries)	1 965 396	2 109 257	2 313 498	1 884 478	1 861 006
Energy efficient lights (luminaires and ballasts)	–	–	–	–	–
Total net capex	2 336 539	2 277 326	2 435 451	2 144 481	2 117 771

Source: United Energy, Regulatory Proposal 2011–2015—public lighting model, November 2009.

Table 19.24 United Energy, forecast capex, forthcoming regulatory control period ($, 2010)

Capex (net of customer contributions)	Forecast				
	2011	**2012**	**2013**	**2014**	**2015**
Poles and brackets	198 394	118 991	371 321	483 905	1 062 444
Existing lights (luminaries)	1 516 546	1 485 347	1 473 642	914 442	1 117 835
Energy efficient lights (luminaires and ballasts)					
Total net capex	1 714 941	1 604 338	1 844 963	1 398 347	2 180 279

Note: Negative capex figures are due to customer contributions for replacing existing lights (MV80) with energy efficient lights (T5), being greater than the capex for existing lights.

Source: United Energy, Regulatory Proposal 2011–2015—public lighting model, November 2009.

United Energy's model shows a T5 roll out commencing in 2009 and continuing during the forthcoming regulatory control period. United Energy also noted that its forecast replacement of public lighting assets was derived from their internal asset replacement model.

The initial capital installation costs of the T5 lights will be fully funded by customer (council) contributions, not by United Energy. During the forthcoming regulatory control period, the costs associated with the installation of poles and brackets and the replacement of T5 lights are incorporated in United Energy's forecast capex requirements. This capex will be recovered through OMR charges.

Current and proposed operating and maintenance expenditure

United Energy's public lighting model provided actual and forecast opex for the current and forthcoming regulatory control periods, respectively (tables 19.25 and 19.26).

Table 19.25 United Energy, opex, current regulatory control period ($, 2010)

	Actual				Forecast
	2006	**2007**	**2008**	**2009**[a]	**2010**
Total opex	2 725 486	2 330 577	1 314 466	2 094 422	2 068 334

Source: United Energy, Regulatory Proposal 2011–2015—public lighting model, November 2009.

(a) Figure provided is an estimate as the regulatory accounts have not been finalised (United Energy, Regulatory Proposal 2011–2015—public lighting model, November 2009).

Table 19.26 United Energy, forecast opex, forthcoming regulatory control period ($, 2010)

	Forecast				
	2011	**2012**	**2013**	**2014**	**2015**
Total opex	3 374 730	3 367 508	3 360 286	3 353 064	3 345 843

Source: United Energy, Regulatory Proposal 2011–2015—public lighting model, November 2009.

Limited building block approach

United Energy applied a limited building block approach to public lighting assets it owns, consistent with the AER's Framework and approach paper and the AER's November 2009 public lighting model.[16]

19.5 Summary of submissions

The AER received submissions on the Victorian DNSPs' public lighting pricing proposals from the following parties:

- Darebin City Council (Darebin)
- Municipal Association of Victoria (MAV)
- Streetlight Group of Councils (SGC).

Darebin expressed concerns regarding the magnitude of the Victorian DNSPs' proposed increases in public lighting operations and maintenance charges including the price differences between small-scale and bulk roll-out of T5 lights. Darebin also

16 United Energy, *Regulatory Proposal 2011–2015*, November 2009, p. 203.

noted a lack of clarity regarding the contestability status of various public lighting services.[17]

The MAV, representing the interests of municipal councils in Victoria, requested that the AER also review Compact Fluorescent Lighting (CFL) charges as part of the review of public lighting charges for the forthcoming regulatory control period.

The MAV requested that the AER assess CFL charges under the ‘fair and reasonable’ provision of ESCV Guideline 14.[18] MAV also expressed concerns about the proposed increases in tariffs, the variations in costs and prices between the DNSPs’ networks, and also CitiPower’s and Powercor’s proposed failure rates for T5 lights.[19]

The SGC submitted concerns regarding the Victorian DNSPs’ treatment of the capital cost of replacing public lights as being funded by the Victorian DNSPs rather than through customer (council) contributions.[20]

The SGC held concerns that the labour rates and input costs proposed by Victorian DNSPs were inconsistent with available market prices. They also had concerns with the magnitude of Victorian DNSPs’ proposed Geographical Information System (GIS) charges, surcharges, overhead costs and the operation, maintenance and replacement costs for T5 lights.[21]

SGC submitted that the AER should reclassify public lighting services as 'Negotiated Distribution Services'. SGC also suggested that there are a number of framework issues in public lighting regulation that require resolution prior to the AER establishing public lighting charges which are compliant with the NER.[22]

Citelum, an international public lighting services provider, sought clarification from the AER regarding operation of the public lighting regulatory framework in Victoria. In particular, Citelum sought to understand if councils could contract with a separate entity, such as Citelum, to install new public lights on a DNSP’s existing distribution power poles.[23]

19.6 Consultant review of labour rates

The AER engaged Impaq Consulting (Impaq) to review the labour costs for all alternative control services, including public lighting. Specifically, Impaq was asked to report on the reasonableness of the Victorian DNSPs proposed hourly labour rates for public lighting services.[24]

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[17] Darebin city council, *Submission to the AER—Victorian Electricity Distribution Network Service Providers' Regulatory Proposals*, February 2010, pp. 1-2.

[18] ESCV, *Electricity Industry Guideline No.14—Provision of services by electricity distributors Issue 1*, April 2004.

[19] MAV, *Submission to the AER—Victorian Electricity Distribution Network Service Providers' Regulatory Proposals*, February 2010, pp. 1-2.

[20] Streetlight Group of councils, *Submission to the AER - Victorian Electricity Distribution Network Service Providers' Regulatory Proposals, February 2010,* p. 6.

[21] ibid., pp. 2-3.

[22] ibid., pp. 16-17.

[23] Citelum, *letter to the AER*, 23 March 2010.

[24] Public versions of the DNSPs’ public lighting models are available on the AER’s website at: http://www.aer.gov.au/content/index.phtml/itemId/732540.

The AER has published a public version of Impaq's report—removing confidential data—with this draft decision.

In its review of labour rates, Impaq referenced the AER's 2009 final decision which established the following labour rates for public lighting services:

- labour rate (normal hours) of $71.41 per hour; and
- labour rate (night patrols) of $82.12 per hour.[25]

Impaq also observed that public lighting activities consisted of:

- repair, replacement and maintenance of public lighting performed during normal business hours
- routine patrol of public lighting on major roads performed after hours.

Impaq noted that the competencies required for the first activity are that of a distribution line worker, and for the purposes of its report assumed that line workers would undertake both activities.[26] Impaq considered that the appropriate comparative charge out labour rates for public lighting services should be assessed based on the following:

- build up of a charge out rate based on wage rates for distribution line workers plus on-costs, overheads and a profit margin
- comparative rates from other jurisdictions
- comparative benchmarked rates.

To allow for variations in charge out rates between the Victorian DNSPs, Impaq calculated a low case and high case labour rate. Impaq's assessment of reasonable charge out rates incorporated wage rates, on-costs, overheads and profit margins in both its low and high case scenarios.

Impaq referred to the AER's most recent draft decision on Energy Australia's 2009–10 to 2014–15 revenue determination for alternative control (public lighting services). This decision followed a direction from the Australian Competition Tribunal for the AER to review its earlier decision.[27] In its draft decision the AER recommended labour rates of $57.00 per hour and $79.00 per hour for normal hours and after-hours (night patrols) respectively.[28]

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25 AER, *Energy Efficient Public Lighting Charges—Victoria - Final Decision*, February 2009, p. 40 (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 8).

26 Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 5.

27 Australian Competition Tribunal decision, *Application by EnergyAustralia and Others* (No 2) [2009] ACompT 9, 25 November 2009.

28 AER, *EnergyAustralia draft distribution determination 2009-10 to 2014-15—Alternative control (public lighting services)*, February 2010 (in Impaq Consulting, *Reasonableness if electricity industry labour rates for public lighting services*, March 2010, p. 30).

Impaq also referred to the annual charge out survey conducted by the National Electrical Contractors Association (NECA) for 2009. Impaq noted that the NECA survey indicated that the average hourly charge out rate was $74.00 although there were wide variations above and below this figure.[29]

In its recommendations, Impaq also provided the hourly charge out rates for public lighting services, built up from wage rates for line workers. These recommendations included charge out rates of:

- between $50.00 and $74.00 per hour for normal hours
- between $55.00 and $82.00 per hour for after hours.[30]

Impaq advised the AER that from Impaq's analysis, it would appear that the competencies required for the repair and maintenance of public lighting are somewhat less than that of other line works. Furthermore, the reference rates found for public lighting are in the lower comparative ranges. On this basis, Impaq recommended that the hourly charge out rate for public lighting should be limited to the range of $57.00 to $74.00 per hour.[31]

19.7 Issues and AER considerations—operating expenditure

In its 2004 public lighting decision, the ESCV allowed a 10 per cent increase over and above the charges proposed by Victorian DNSPs. This buffer was in recognition that the ESCV's 2004 public lighting model was based on benchmark assumptions and that the generic input costs in the model did not accurately reflect the actual operations of each Victorian DNSP.[32]

The AER removed this 10 per cent buffer in its 2011–15 model, on the basis that the Victorian DNSPs were now required to provide their individual input costs and forecast opex and capex for 2011–15.[33] For this reason, input costs proposed by the Victorian DNSPs may differ in their respective models, in recognition that individual DNSPs have different cost drivers. The AER has considered this when assessing the input costs proposed by the Victorian DNSPs for 2010 which differ to those currently used by the DNSPs for that year and approved by the AER in December 2009.

19.7.1 Labour rates and escalation

The AER published a set of labour rates in its 2009 final decision which it considered to be fair and reasonable at the time. These were $71.41 for normal hours and $82.12 for night patrols and were applied to all luminaire types in the AER's assessment of the Victorian DNSPs' OMR charges for 2010, approved in December 2009.[34]

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29 Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 30.
30 ibid., p. 32.
31 ibid., p. 36.
32 ESCV, *Review of public lighting excluded service charges, final decision*, August 2004, pp. 33-34.
33 AER, 2011–15 *Victorian electricity distribution determination—revised public lighting model*, November 2009.
34 AER, *Energy Efficient Public Lighting Charges—Victoria*, February 2009, p. 40.

The AER's 2011–15 public lighting model permits the Victorian DNSPs to propose annual input cost escalation. The AER has therefore assessed the real labour cost escalators above CPI for the forthcoming regulatory control period.

Victorian DNSP regulatory proposals

The Victorian DNSPs' proposed labour rates for normal hours and after hours (night patrols) are provided in tables 19.27 and 19.28 respectively. Each Victorian DNSPs' proposed annual escalation rates (where applicable) are shown in table 19.29.

Table 19.27 Victorian DNSP proposed labour rates (normal hours), per hour ($, 2010)

	2010	2011	2012	2013	2014	2015
CitiPower	78.12	80.07	82.07	84.23	86.46	88.61
Powercor	78.12	80.07	82.07	84.23	86.46	88.61
Jemena	71.41	73.14	75.06	77.11	79.13	81.05
SP AusNet	75.38	75.38	75.38	75.38	75.38	75.38
United Energy	71.41	68.42	70.20	72.02	73.90	75.82

Source: Victorian DNSPs' regulatory proposals.

Table 19.28 Victorian DNSP proposed labour rates for night patrols (after hours), per hour ($, 2010)

	2010	2011	2012	2013	2014	2015
CitiPower	89.84	92.08	94.38	96.87	99.43	101.91
Powercor	89.84	92.08	94.38	96.87	99.43	101.91
Jemena	82.12	84.11	86.32	88.67	91.00	93.21
SP AusNet	86.69	86.69	86.69	86.69	86.69	86.69
United Energy	82.12	78.68	80.73	82.83	84.98	87.19

Source: Victorian DNSPs' regulatory proposals.

Table 19.29 Victorian DNSP proposed real escalation rates for labour (per cent)

	2011	2012	2013	2014	2015
CitiPower	2.49	2.49	2.64	2.64	2.49
Powercor	2.49	2.49	2.64	2.64	2.49
Jemena	2.43	2.63	2.73	2.63	2.43
SP AusNet	–	–	–	–	–
United Energy	–4.18	2.60	2.60	2.60	2.60

Source: Victorian DNSPs' regulatory proposals.

In their regulatory proposals, CitiPower and Powercor both stated that their proposed labour rate (normal hours) of $78.12 for 2010 was derived from taking the AER's approved labour rate of $71.41 (2008) and applying the wage rate escalators of 4.55 per cent and 4.64 per cent in 2009 and 2010 respectively. Both DNSPs noted that these wage rate increases are based on the weighted average of the approved growth rates for the Electrical Trades Union and the Association of Professional Engineers, Scientists and Managers Australia.[35]

In terms of labour rates for night patrols (after hours), both CitiPower and Powercor maintained a 15 per cent loading on the labour rate for normal hours. Labour rates for 2011–15 are adjusted by CitiPower's and Powercor's proposed real labour escalation rates provided in table 19.29.

United Energy proposed 2010 labour rates of $71.41 for normal hours and $82.12 for after hours are consistent with the rates established by the AER in its 2009 final decision. United Energy also proposed a 2011 labour rate (normal hours) of $68.42, while labour rates from 2012 are escalated by 2.6 per cent per annum. United Energy has also proposed a 15 per cent surcharge on the labour rates for after hours work.[36]

Jemena's proposed labour rate of $71.41 for 2010 is also consistent with the rate established by the AER in its 2009 final decision. Table 19.29 shows the escalation Jemena applied to its labour rates over 2011–15.

SP AusNet proposed a contractors labour rate (normal hours) of $75.38 for 2010, which is described by SP AusNet as the .SP AusNet also proposed an after hours labour rate of $86.69 for 2010. While these rates are higher than the labour rates established by the AER in its 2009 final decision, SP AusNet does not propose to escalate labour rates during 2011–15.[37]

Submissions on DNSP regulatory proposals

The SGC stated that it disagrees with the Victorian DNSPs' proposed labour rates, particularly those of CitiPower and Powercor where a separate overhead allocation is provided in the public lighting charges. It also submitted that the Victorian DNSPs' proposed labour rates were higher than those charged by electrical contractors running their own businesses.[38]

The SGC noted that its view is supported by the National Electrical and Communications Association which conducted a survey of charge-out and pay rates of Australia's electrical contractors in September and October 2008. The survey noted the average hourly rate for an electrical tradesperson in Australia was $66.00, although there were wide variations to this figure.[39]

35 CitiPower, *Regulatory Proposal2011–15— public lighting model* (updated March 2010); Powercor, *Regulatory Proposal 2011–15—public lighting model*, (updated March 2010).
36 United Energy, *Regulatory proposal 2011–2015—public lighting model*, November 2009.
37 SP AusNet, *Regulatory proposal 2011–15—public lighting model*, November 2009.
38 SGC, *Submission to the AER*, February 2010, p. 13.
39 NECA, *Electrical contractor charge-out survey*, February 2009 (available at http://www.electricalsolutions.net.au/articles/29709-Electrical-contractor-charge-out-survey); SGC, *Submission to the AER*, February 2010, p. 13.

Consultant review

In its report to the AER, Impaq provided an assessment of reasonable charge out rates for providing public lighting services during normal and after hours. As discussed previously, Impaq's assessment was based on the following variables:

- wage rates
- available hours—determination of the available working hours per year
- on-costs—those costs of employment in addition to wages
- overheads—an allocation of overhead costs (for example, supervision, premises costs, administration, human resources, information technology, communications etc)
- profit margin.

Impaq's assessment of each of these variables is provided below.

Wage rates

Impaq identified hourly pay rates of between $33.00 and $41.00 for distribution line workers in Australia. It noted that applicable superannuation rates varied between 9 per cent and 14 per cent.[40] Impaq also observed the Hays salary survey for 2009, which published annual pay rates for electricians of $60 000 to $70 000.[41]

Available hours

Impaq's calculation of available hours per annum is shown in table 19.30. To determine the number of available working hours per year, Impaq used a base of 365 days per year and deducted the items listed in the table to determine a total of 1642.5 available work hours per annum.

40 Based on a number of advertised positions across Seek, Mycareer, Jobseeker, Careerone, Indeed, Ergon energy, Energex, Integral Energy, Country Energy and Energy Australia (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 24).

41 http://www.careerone.com.au/news-advice/salary-centre/salary-surveys-20080506/?247SEO=N&CMP=KNC-SEM&referrer=geditorial&type=P&WT.srch=1 (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 24).

Table 19.30 Impaq calculation of annual available working hours

Item	Value	Comment
Public holidays	10 days	Victorian Government Gazette
Personal/carer's leave	12 days	Electrical Power Industry Award 2010
Annual leave	20 days	Fair Work—National Employment Standards
Working days per annum	219 days	
Hours per day	7.5 hours	Some DNSPs have 9 day fortnights with 8.33 hours per day, which gives the same net result
Available hours per annum	1642.5 hours	

Source: Impaq Consulting, Reasonableness of electricity industry labour rates for public lighting services, March 2010, p. 25.

On costs

Table 19.31 shows Impaq's assessment of labour on-costs, including both low case and high case scenarios. These reflect the costs, over and above wages, of employing personnel.

Table 19.31 Impaq review findings regarding employment on costs (per cent)

Item	Low Case	High Case	Comment
Superannuation	9	14	The low case is just the Superannuation guarantee value of 9 per cent. The high case at 14 per cent makes allowance for the higher superannuation contributions associated with some parts of the Power industry
Long service leave	1.5	2.3	The low case is based on Long service leave of 12 weeks after 15 years service. The high case is based on 12 weeks Long service leave after 10 years of service (which has been characteristic of the public sector rather than the private sector)
Workcover (estimate)	1	3.0	The low case and high case represent the range of values that are common. The low case is drawn from one DB submission.
Payroll tax	4.95	4.95	Victorian Payroll Tax Rate
Annual leave loading (17.5 per cent)	1.3	1.3	Based on 17.5 per cent loading on 4 weeks annual leave
Total on costs	17.75	25.55	The low case is just the Superannuation guarantee value of 9 per cent. The high case at 14 per cent makes allowance for the higher superannuation contributions associated with some parts of the Power industry

Note: Totals rounded to the nearest dollar.
Source: Impaq Consulting, Reasonableness of electricity industry labour rates for public lighting services, March 2010, p. 26.

Overheads

Impaq stated that overhead rates varied considerably across businesses, depending on the nature of the industry, the scale of the business, the level of outsourcing, and whether costs are included in overheads or on-cost categories.[42] These overheads include costs of supervision, building tenancy, administration, human resources, IT and communications.[43]

Impaq also stated that because out of hours activities have been a standard business requirement for the DNSPs, it assumed that overheads have been allocated across both normal hours and out of hours operations. Accordingly, it would be expected that overhead rates would vary from about 10 per cent to 25 per cent based on similar businesses. Impaq also noted that the AER accepted an overhead rate of 25 per cent for New South Wales DNSPs in relation to public lighting services.[44]

Profit margin

Impaq considered that because alternative control services are not capital intensive, applying a building block methodology return of capital and return on capital (for standard control services) does not yield meaningful profit margins applicable to alternative control services.[45] Impaq also considered that profit margins of between 3 to 8 per cent are common for companies delivering services comparable to those provided by the DNSPs in relation to alternative control services.[46]

Impaq also contended that due to the low risk nature of the revenue earned by DNSPs for alternative control services, it is arguable that margins should be at the lower end of the 3 per cent to 8 per cent range.[47]

Based on these assumptions, Impaq provided an assessment of an appropriate range of total margins above direct wages cost, which is summarised in table 19.32.

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42 Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, pp. 26-27.

43 ibid., p. 24.

44 AER, *Energy Australia draft distribution determination 2009-10 to 2014-15 Alternative Control (public lighting) services—draft decision*, February 2010, p. 22 (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 27).

45 The AER notes that its public lighting building block model applies a return of capital and a return on capital to the capital expenditure associated with providing public lighting services.

46 Australian Financial Review, Profits 2010, 10 March 2010, p.12. Major service companies Earnings Before Interest and Tax (EBIT) margins of between 3 per cent and 8 per cent. Some instances are: United Group Limited (UGL), which provides services across several industries including electricity, have historically achieved net profit margins of about 5 per cent. Norfolk (which includes O’Donnel Griffin electrical contracting) has an EBIT margin of 3 per cent in recent years. Downer EDI 5 per cent, Leighton Holdings 7.5 per cent, in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 27).

47 Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 27.

Table 19.32 Impaq assessment findings, total margin above direct cost (per cent)

Item	Low case	High case
On costs	18	26
Overheads	7	25
Profit margin	3	8
Total	28	59

Source: Impaq Consulting, Reasonableness of electricity industry labour rates for public lighting services, March 2010, p. 27.

Charge out rate assessment

Table 19.33 shows the resulting charge out rate for normal hours based on Impaq's calculations. Impaq stated that the charge out rates for after hours are determined by adding a 16 per cent penalty rate for afternoon shift as required in relevant award wage requirements.[48]

Table 19.33 Impaq, charge out rate assessment (dollars per hour)

Labour category	Charge out rate—normal time		Charge out rate—after hours	
	Low case	High case	Low case	High case
Lineworker	42.82	71.19	49.67	82.58

Source: Impaq Consulting, Reasonableness of electricity industry labour rates for public lighting services, March 2010, p. 28.

Comparison rates from other states

Impaq noted that the AER's draft decision for EnergyAustralia's 2009–10 to 2014–15 distribution determination recommended that labour unit rates should be $57.00 per hour for standard hours and $79.00 per hour for out of hours activities (including night patrols).[49]

Impaq also noted that submissions to the AER for its 2010–11 to 2014–15 Queensland draft decision, in relation to public lighting services, included proposed charge out rates of $57.37 for normal time and $80.21 for overtime.[50]

Comparative benchmark rates

Impaq noted that NECA's 2009 charge out survey published an average hourly charge out rate of $74.00 for an electrical tradesperson in Australia.[51] Impaq noted while

48 Electrical Power Industry Award—2010, page 24 (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 28).

49 AER, *EnergyAustralia draft distribution determination 2009–10 to 2014–15—Alternative control (public lighting services)*, February 2010 (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 30).

50 Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 30.

51 http://www.neca.asn.au/ (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 30).

there were wide variations above and below this figure, it observed that the most common rate (used by 31.6 per cent of respondents) is between $60.00 and $70.00, but nearly as many (30.3 per cent) charge between $70.00 and $80.00.[52]

Impaq summary and recommendations

Table 19.34 provides Impaq's summary of the comparative charge out rates for distribution lineworkers.

Table 19.34 Impaq, summary of comparative Victorian DNSP lineworker charge out rates (dollars per hour)

Distribution lineworkers	Charge out rate —normal time		Charge out rate —after hours	
	Low case	High case	Low case	High case
Rates build up from wage rates	50	74	55	82
AER draft determination for Energy Australia	57	57	79	79
Third party submissions to previous jurisdictions' regulatory determinations	57	57	80	80
ETSA	84	84	105	105
Country Energy	80	80	140	140
Energy Australia	88	88	154	154
NECA benchmark (less $10/hr vehicle cost)	50	80	–	–
CitiPower	132	132	145	145
Jemena	83	92	275	275
Powercor	124	124	136	136

Source: Impaq Consulting, Reasonableness of electricity industry labour rates for public lighting services, March 2010, pp. 32–33.

Impaq also noted that based on the information in table 19.34:

> It would appear from our analysis that the competencies required for the repair and maintenance of public lighting is somewhat less than that of other line work (eg: glove and barrier). Furthermore the reference rates found for public lighting are in the lower comparative ranges.[53]

Accordingly, Impaq recommended to the AER that hourly rates should be in the range of $57.00 to $74.00 per hour, and that the AER should not increase the charge out

52 Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services*, March 2010, p. 30.

53 ibid, p. 36.

rates for public lighting services in 2010 from the rates published in the AER's 2009 final decision for public lighting charges in Victoria.[54]

AER considerations

The AER published a set of labour rates in its 2009 final decision which it considers were fair and reasonable. These labour rates are $71.41 per hour for normal hours and $82.12 per hour for after hours work.[55]

In establishing these rates, the AER considered the ESCV's 2008 draft decision to retain the 2004 labour rates, and the submissions from the Streetlight Group of Councils, CitiPower and Powercor. The AER also reviewed wage cost data from the Australian Bureau of Statistics in order to assess the magnitude of wage cost pressure since the ESCV's August 2004 final decision on public lighting labour rates. The AER noted that the 19.01 per cent increase in the wage cost index between June 2004 and June 2008 was more indicative of actual cost pressures, rather than the forecast cost increases submitted by CitiPower and Powercor.[56]

The AER stated in its 2009 final decision that these labour rates would be applied when assessing DNSPs' revised OMR charges for all luminaires that will commence from 1 January 2010.[57] This assessment was subsequently carried out by the AER in December 2009, with all public lighting OMR charges updated from 1 January 2010.

The AER considered Jemena's and United Energy's 2011–15 regulatory proposals which adopted these updated labour rates for 2010, escalated in 2011–15 by labour cost growth. The AER also considered SP AusNet's proposal for a 2010 labour rate of $75.38 with no labour escalation for 2011–15, and the proposals of CitiPower and Powercor for rates of $78.12 in 2010, followed by annual escalation for 2011–15.

The AER has also had regard to the recommendations of Impaq's report, particularly the wage rates build up with a low case of $43.00 per hour to a high case of $71.00 per hour. These rates include on-costs from employing individuals or contractors across the electricity industry.

On balance, the AER is persuaded by Impaq's recommendations, particularly given the breadth of data in its report. The AER has also attached weight to the rates established in the 2009 final decision. Accordingly, the labour rates that the AER accepts for 2010 will be:

- $71.41 per hour for normal hours
- $82.12 per hour for after hours (night patrols).

Further to this, the AER also proposes to adopt the platform vehicle rates of $10.00 per hour, as established in the 2009 final decision.[58]

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54 AER, *Energy Efficient Public Lighting Charges—Victoria (Final)*, February 2009 (in Impaq Consulting, *Reasonableness of electricity industry labour rates for public lighting services,* March 2010, p. 36).

55 AER, *Energy Efficient Public Lighting Charges—Victoria (Final)*, February 2009, p. 40

56 ibid., pp. 38–39.

57 ibid., p. 40.

58 ibid., p. 40.

Labour escalation

The AER's assessment and draft decision on labour escalators for standard control services is set out in appendix K. The AER has applied these labour cost escalators for outsourced labour to the 2010 labour rates in its draft decision on public lighting OMR charges for each year of the forthcoming regulatory control period. The percentage increases in labour rates for each DNSP for the forthcoming regulatory control period are set out in table 19.35.

Table 19.35 Draft decision, real escalation for outsourced labour (per cent, per annum)

	2011	2012	2013	2014	2015
CitiPower	0.87	1.48	1.89	1.87	0.69
Powercor	0.87	1.48	1.89	1.87	0.69
Jemena	0.87	1.48	1.89	1.87	0.69
SP AusNet	0.87	1.48	1.89	1.87	0.69
United Energy	0.87	1.48	1.89	1.87	0.69

Source: AER analysis.

19.7.2 Materials costs escalation

The Victorian DNSPs' proposed public lighting material cost escalation are presented in table 19.36.

Table 19.36 Victorian DNSP proposed material cost escalators (per cent, per annum)

	2011	2012	2013	2014	2015
CitiPower	3.65	2.43	1.80	1.58	1.60
Powercor	3.65	2.43	1.80	1.58	1.60
Jemena	2.88	2.09	1.62	1.64	1.67
SP AusNet	–	–	–	–	–
United Energy	1.60	1.60	1.60	1.60	1.60

Source: Victorian DNSPs' regulatory proposals.

The AER has set out in appendix K its assessment of material cost escalation for this draft decision. The AER notes that steel, rather than wood or concrete, is the predominant form of material used for public lighting poles. Appendix K deals with cost escalation for steel but not for the other materials used for public lighting such as for the various components within the luminaire (eg ballast, photo-electric cells and lamps).

The ESCV's 2004 public lighting model did not include escalation for materials (or labour). In this draft decision, the AER has applied materials costs escalation to standard control services and, where appropriate, alternative control services. As noted above, steel is the predominant material used for public lighting poles. This is the only materials escalator that has been applied by the AER to public lighting services. Other materials—like lamps and PE cells—have no comparable material escalator that the AER considers appropriate to apply.

Accordingly, the steel cost escalators set out in appendix K have been applied to the 2010 unit cost of poles and brackets on non-dedicated poles[59] to derive unit costs for each year of the forthcoming regulatory control period.

Table 19.37 shows the AER's draft decision on public lighting cost escalation for poles and brackets, where the AER weighted the Victorian DNSPs' proposed materials escalators by 45 per cent, to reflect only the purchase price for steel.

Table 19.37 Draft decision, real escalation for public lighting poles and brackets (per cent, per annum)

	2011	2012	2013	2014	2015
CitiPower	3.02	0.83	-0.43	-1.14	-1.39
Powercor	3.02	0.83	-0.43	-1.14	-1.39
Jemena	3.02	0.83	-0.43	-1.14	-1.39
SP AusNet	3.02	0.83	-0.43	-1.14	-1.39
United Energy	3.02	0.83	-0.43	-1.14	-1.39

Source: AER analysis.

The AER notes that the Victorian DNSPs' public lighting charges are also indexed by CPI, which in the long run reflects the general movement in prices and input costs throughout the economy. This ensures that the Victorian DNSPs receive compensation in charges for this effect.

19.7.3 Traffic management costs

Victorian DNSP regulatory proposals

The ESCV's public lighting model did not assume any costs in relation to traffic management. However, in submissions to the AER, the Victorian DNSPs noted that traffic management costs have become more prevalent since the ESCV's 2004 decision due to regulatory changes.

The Victorian DNSPs regulatory proposals included a wide disparity in traffic management costs for public lighting services for the forthcoming regulatory control period.

Table 19.38 sets out the traffic management costs for each year of the forthcoming regulatory control period, as proposed in the Victorian DNSPs' respective public lighting models.

[59] The 2010 unit costs are $500.00 for poles and brackets and $40.00 for brackets on non-dedicated poles.

Table 19.38 Victorian DNSPs' total traffic management costs, 2011–15, all light types ($, 2010)

	MV80	SHP 150	SHP 250	T5 (2x14W)
CitiPower	572 077	1 114 669	441 824	1 501 271
Powercor	974 320	1 643 994	702 722	4 877 408
Jemena	16 512	323 614	103 886	5 988
SP AusNet	58 970	25 000	25 000	184 883[a]
United Energy	18 296	245 579	102 048	–

Note: SP AusNet figures updated in a resubmitted model, 17 March 2010.
(a) Figure for T5 (2x14W) also includes proposed traffic management costs for T5 (2x24W) lights.
Source: Victorian DNSPs' regulatory proposals.

Submissions on DNSP regulatory proposals

Only one submission was received on this issue, from SGC, who noted that traffic management costs were not an input in the 2004 public lighting model.[60]

AER considerations

In their regulatory proposals the Victorian DNSPs advised that their traffic management costs were a consequence of complying with the Road Management Act 2004 (Vic) (RMA).

It is noted that prior to their 2011–15 regulatory proposals, the Victorian DNSPs had not proposed costs associated with traffic management, despite being obliged to conform to the RMA since 2004. Therefore, the Victorian DNSPs have either been funding this cost outside of their public lighting revenue, not incurring the costs or not complying with the RMA. During development of the public lighting model, the Victorian DNSPs explained to AER staff that traffic management had become a more significant cost since 2004.[61]

The AER considers that the Victorian DNSPs' forecast costs for traffic management have not been adequately explained. It is unclear whether the forecasts reflect reasonable assumptions and forecasting methodologies.

The AER is of the view that the Victorian DNSPs will incur expenditure associated with complying with the RMA. However, given the wide disparity in proposed costs, shown in table 19.38, the observed differences in proposed traffic management costs among the Victorian DNSPs suggests these forecasts may not be reflective of the efficient costs for providing public lighting services.

The AER has evaluated the Victorian DNSPs' forecast expenditure by comparing the relative size of each DNSP to provide benchmarks for assessment of the expenditure. As Powercor and SP AusNet are both predominantly rural DNSPs, the AER has taken

60 SGC, *Submission to the AER*, February 2010, p. 13.
61 SP AusNet, *Draft model for regulation of public lighting services in Victoria*, 16 October 2009, p. 2.

SP AusNet's forecast traffic management costs for each major light type (MV80, S-HP150, S-HP250 and T5) and applied these costs to Powercor, adjusted by a factor of 2.26 to reflect the larger forecast number of lights in the latter's area.

Based on the more stringent requirements for traffic management likely to apply in the CBD due to population and urban density, CitiPower's forecast costs were estimated by the AER to be approximately four times larger than those of Jemena's (the next closest comparable urban DNSP). Accordingly, using Jemena's forecast annual traffic management costs of$90 000, the AER has derived a figure of $360 000 in annual traffic management costs for CitiPower. Furthermore, the AER has also apportioned forecast traffic management costs by the major light types as well as the location of these lights (95 per cent on major roads and 5 per cent on minor roads). These calculations were done based on the methodology used by Jemena for apportioning its traffic management costs.[62]

SP AusNet's, Jemena's and United Energy's traffic management costs were not amended from that which they proposed.

The AER's draft decision on traffic management costs is set out in table 19.39.

Table 19.39 Draft decision, total traffic management costs, 2011–15 ($, 2010)

	MV80	SHP 150	SHP 250	T5 (2x14W)
CitiPower	25 100	308 184	122 032	64 835
Powercor	133 273	56 500	56 500	106 814
Jemena	16 512	323 614	103 886	5 988
SP AusNet	58 970	25 000	25 000	184 883[a]
United Energy	18 296	245 579	102 048	–

(a) Figure for T5 (2x14W) also includes proposed traffic management costs for T5 (2x24W) lights.
Source: AER analysis.

19.7.4 Other costs

Victorian DNSP regulatory proposals

As part of their respective public lighting models, the Victorian DNSPs proposed $100 000 in annual Geographical Information System (GIS) costs for the forthcoming regulatory control period.

In response to AER enquiries, United Energy stated that the annual $100 000 is a notional operating cost for the ongoing management, operation and maintenance of all public lighting systems which work together with the GIS.[63] United Energy advised that systems are required which feed into GIS for the sole purpose of public lighting, including billing and enabling councils to access web based information on public

[62] Jemena, *Regulatory Proposal 2011–15—public lighting model*, November 2009 (updated in March 2010).
[63] Email from United Energy to AER staff on 5 March 2010.

lighting service provision. United Energy also explained that GIS requires ongoing operational and management costs, which are mainly updates on a daily basis to the public lighting component of the GIS system.

SP AusNet stated that the GIS was fundamental to the management of its public lighting system.[64] It explained that its GIS serves as the primary record of lights connected to the SP AusNet network. It noted that in addition to recording the spatial location of each light, the GIS records the light type, the network connection details and customer details, among others. The GIS then feeds into the SP AusNet billing system and web based customer access information.

SP AusNet also noted that the $100 000 represents the annual cost to SP AusNet in managing and operating these systems, as well as some portion of its capital components. SP AusNet proposed that it would be appropriate that this expenditure be retained because the management and operation of the GIS would be ongoing.

SP AusNet also proposed additional costs specific to the north and east regions for MV80 and T5 luminaires.

Jemena noted that clause 5.1.1 of the Public Lighting Code requires it to provide public lighting data to a public lighting customer via its website.[65] Clause 5.1.2 of the Code specifies the public lighting data that must be provided. Jemena advised that the GIS expenditure represents the notional ongoing operating cost of the GIS for the maintenance of public lighting data including Jemena's reporting obligation under clause 5.2.1of the Code.

Jemena also noted that the $100 000 per annum is not a one off cost to establish the spatial location of the assets over the 2006–10 regulatory control period.

Submissions on DNSP regulatory proposals

SGC understood the $100 000 per annum cost for GIS services was originally included to enable the Victorian DNSPs establish their spatial location of assets. SGC argued that as DNSPs had now established these locations, on-going funding was unnecessary.

SGC also submitted that this cost must be removed and that a GIS component should fairly be included when public lighting assets are changed or new assets installed and the spatial location needs to be changed.[66]

AER considerations

The AER has considered the information provided by the Victorian DNSPs and the submission made by SGC. The AER has accepted the information provided by all Victorian DNSPs on GIS costs and notes that they have relevant obligations under the Code. The AER considers that GIS costs in the current model remain appropriate. The Victorian DNSPs did not amend these costs from those in 2004. Therefore the $100 000 per annum proposed will continue to apply in the 2011–15 regulatory control period.

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64 Email from SP AusNet to AER staff on 5 March 2010.
65 Email from Jemena to AER staff on 5 March 2010.
66 SGC, *Submission to the AER*, February 2010, p. 12.

In relation to SP AusNet's other costs for the north and east regions, the AER notes SP AusNet did not explain in detail what these additional costs related to that. Noting that SP AusNet already receives a 5 per cent premium in costs for rural areas, the AER has rejected these additional costs.

19.8 Issues and AER considerations—capital expenditure

This section outlines the Victorian DNSPs' proposals in relation to public lighting capital expenditure forecasts and the AER's assessment of those forecasts.

19.8.1 Transitional adjustments—recovery of capex spent in 2009–10

Departing from the ESCV's approach and moving to the AER's public lighting methodology involves DNSPs needing to recover actual capex for 2009 and 2010 that would have been recovered under the previous model. Accordingly, as a result of the transition from the 2–year lagged actual capex model to the forecast capex model DNSPs are now required to provide forecast capex costs. As discussed below, the AER has considered the transitional adjustment price smoothing factors proposed by the Victorian DNSPs with regard to recovery of actual capex for 2009 and 2010.

Victorian DNSP regulatory proposals

For the purposes of recovering the depreciation and the return on capital for actual capex undertaken in 2009 and 2010 but not yet recovered in existing OMR charges, both CitiPower and Powercor proposed adopting a transitional adjustment price smoothing factor of 20 per cent for each year from 2011 to 2015.[67]

Jemena has proposed a transitional adjustment price smoothing factor of 45 per cent in 2011, 25 per cent in 2012, 20 per cent in 2013, 10 per cent in 2014 and 5 per cent in 2015.[68]

United Energy has proposed a transitional adjustment price smoothing factor of 100 per cent in 2011, which is effectively recovering all depreciation and return on capital for 2009 and 2010 in the first year of the forthcoming regulatory control period.[69]

SP AusNet proposed a transitional adjustment price smoothing factor of 100 per cent for the first year of the forthcoming regulatory control period. Similar to United Energy, SP AusNet proposed that it would recover all 2009 and 2010 return on capital and depreciation in 2011.

Submissions on DNSP regulatory proposals

The AER notes that there were no submissions on this issue.

67 CitiPower, *Regulatory Proposal 2011–15—public lighting model*, November 2009 (updated March 2010)*;* Powercor, *Regulatory Proposal 2011–15—public lighting model*, November 2009 (updated March 2010).
68 Jemena, *Regulatory Proposal—public lighting model*, November 2009.
69 United Energy, *Regulatory Proposal - public lighting model*, November 2009.

AER considerations

The AER considers that the transitional adjustment methodology to be adopted should provide for a smoothing of public lighting charges from the current to the forthcoming regulatory control period.

The AER notes that SP AusNet and United Energy seek full compensation for 2009 and 2010 unrecovered expenditure in 2011. The AER considers that adopting this approach would lead to unnecessary price shocks for customers in 2011 (increased charges) and again in 2012 (reduced charges). Consequently, the AER proposes to adopt a transitional adjustment price smoothing factor of 20 per cent in each year of the forthcoming regulatory control period.

The AER considers that this will smooth price variations for customers over the forthcoming regulatory control period, while permitting the Victorian DNSPs to recover the full depreciation and return on capital associated with unrecovered expenditure undertaken in 2009 and 2010.

19.8.2 Failure rates of T5 lights between bulk changes

The AER's 2009 final decision acknowledged that the Victorian DNSPs face a trade-off between price and quality when purchasing luminaires.[70] This section responds to the Victorian DNSPs' proposals with respect to these matters.

Victorian DNSP regulatory proposals

Table 19.40 shows the Victorian DNSPs' proposed failure rates in relation to the percentage of T5 energy efficient lights forecast to fail between bulk changes in the forthcoming regulatory control period.

Table 19.40 Victorian DNSP proposed percentage of lights that fail between bulk changes—2011 to 2015 (per cent)

	MV80	T5 (2x14W)
CitiPower	15.0	19.5
Powercor	15.0	18.5
Jemena	19.6	21.7
SP AusNet	15.0	11.2[a]
United Energy	37.7	11.2

(a) Figure for T5 (2x14W) is the same as the proposed failure rate for T5 (2x24W).
Source: Victorian DNSPs' regulatory proposals.

Each Victorian DNSP, except for United Energy, proposed annual failure rates for MV80s which are unchanged from the proposed failure rates for 2010. In contrast, United Energy's proposed failure rate for MV80 luminaires of 37.7 per cent over 2011–15 is a marked increase from the 15.0 per cent applied in 2010. United Energy

[70] AER, *Energy Efficient Public Lighting Charges—Victoria (Final)*, February 2009, p. 14.

has noted that this figure is consistent with its average GSL broken streetlights for 2005 to 2008.[71]

Jemena noted that its failure rate of 19.6 per cent for MV80 luminaires is based on the data submitted to the ESCV and the published data in the ESCV's annual Comparative Performance Report. Jemena also noted that its failure rate of 21.7 per cent for T5 energy efficient lights is based on:

> - T5 Lamp—8.6 per cent (as per the VSPLAG report)[72]
> - PE Cell—13.12 per cent (based on actual JEN data for MV80 lights from SAP system. The PE Cell used in the T5 lights are the same product used in the MV 80 lights)
>
> Total = 21.72 per cent over 4 years.

Further, in relation to the proportion of lamps that fail between bulk changes, Jemena also noted that:

> …the description should be corrected from 'lamps' to 'lights'. Street light failures are caused by the failure of lamp, PE cell, luminaire, and wiring. This error was pointed out to the ESC in the section 5.1 of JEN submission on the Draft decision energy efficient public lighting charges, dated 31 Dec 2008. That is why the AER's proposed 15.0% failure rate over four years does not corroborate with the ESC's published annual Comparative Performance Report. JEN has submitted failure rate based on actual reported in the report.[73]

Submissions on DNSP regulatory proposals

The AER notes that there were no submissions on this issue.

AER considerations

The AER has assessed the failure rates adopted in its 2009 final decision. It has also reviewed the failure rates from the 2004 ESCV public lighting decision.

The AER notes that United Energy is effectively estimating that almost 40 per cent of its MV80 lamps (that is the globes) will fail before a bulk changeover every 4 years. This estimate appears to be at the very high end relative to the failure rates estimated by the other Victorian DNSPs.

The AER considers that there is insufficient information before it to determine that a 37.7 per cent failure rate for MV80s is representative of United Energy's public lighting network. Consequently, the AER has amended United Energy’s MV80 lamp failure rates to 19.6 per cent, which is in line with that of Jemena, but above United Energy’s 2010 rate of 15 per cent.

Further, the AER considers that the information provided to it by the Victorian DNSPs was insufficient for it to determine that failure rates for T5 lights should be higher than the rate of 11.2 per cent, as established in the AER’s 2009 final decision.

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71 United Energy, *Regulatory Proposal 2011–2015— public lighting model*, November 2009.
72 Victorian Sustainable Public Lighting Action Group, *Evaluation of low energy lights for minor road lighting (final)*, April 2009.
73 Jemena, *Regulatory Proposal 2011–2015—public lighting model*, February 2010.

It is recognised that further information on the performance and failure rates of energy efficient luminaires and components may come to hand over time. However, in the absence of sufficient information, the AER will continue to adopt 11.2 per cent as the proportion of T5 lights that fail between bulk changes. The AER's draft decision on the proportion of MV80 and T5 lights that fail between bulk changes for each of the Victorian DNSPs is provided in table 19.41.

Table 19.41 Draft decision, percentage failure rates of lights between bulk changes, 2011–15 (per cent)

	MV80	T5 (2x14W)
CitiPower	15.0	11.2
Powercor	15.0	11.2
Jemena	19.6	11.2
SP AusNet	15.0	11.2
United Energy	19.6	11.2

Source: AER analysis.

19.8.3 Capex forecasts for 2011–15 regulatory control period

The Victorian DNSPs' proposed capex for the forthcoming regulatory control period are set out in tables 19.3, 19.8, 19.13, 19.19 and 19.24.

As previously discussed, under the AER's approach to public lighting the Victorian DNSPs are now required to provide forecast capex for the forthcoming regulatory control period, with cost inputs based on actual costs. As discussed previously, there is two years (2009 and 2010) worth of unrecovered return on capital and depreciation that the Victorian DNSPs will be entitled to recover in the forthcoming regulatory control period.

Inputs for the cost-build up for capex cover:

- a material premium for rural areas
- labour rates (provided in section 19.7.1)
- elevated platform vehicle rates - urban and rural
- unit costs of luminaires and miscellaneous materials
- number of workers in a crew
- number of luminaires replaced per day and on a per year basis
- costs of poles and brackets
- number of poles and brackets replaced per day and on a per year basis.

The AER notes that the costs for these inputs were established in its 2009 final decision on T5 energy efficient lights.[74]

Victorian DNSP regulatory proposals

Capex forecasts for energy efficient luminaires

The AER has assessed the capex forecasts and sought from the Victorian DNSPs explanations for their capex forecasts and inputs. SP AusNet, responding to AER questions on why its forecast T5 capex was higher than that of other DNSPs, advised that it was funding $94.55 of the cost of T5 luminaires when they replaced MV80s.

As a consequence, SP AusNet's forecast T5 capex for 2011–15 was considerably higher than other DNSPs, resulting in higher OMR charges by SP AusNet.

All other Victorian DNSPs had either zero costs for T5 capex, or in Jemena's case a marginal figure. These forecasts did not significantly impact on their OMR charges.

Capex forecasts for poles and brackets and other lighting types

Section 19.4 sets out the forecast capex for each Victorian DNSP, including the Victorian DNSPs' forecast capex over 2011–15 for existing luminaries and poles and brackets.

Until 2010, Victorian DNSPs' actual capital expenditure on public lighting was recorded in regulatory accounts and used by the ESCV and AER to adjust OMR charges each year. This will no longer be the approach for the 2011–15 regulatory control period where capex is forecast, with accepted forecasts being an input into OMR charges for this period.[75] These charges will be fixed for the forthcoming regulatory control period (except for annual CPI adjustment), providing certainty to municipal councils on the level of charges over the period.

The AER has observed large increases in proposed capex from 2010 and the forthcoming regulatory control period compared to the actual capex over 2005–09. The AER sought the Victorian DNSPs' explanation for this divergence. Their responses are outlined below.

CitiPower and Powercor stated that their respective increases in capex from 2010 to 2011 were due to a 'step change' to account for the change in methodology between those years. Further, they observed that up until 2010 the cost inputs came from their accounting systems whereas the methodology from 2011 and beyond was based on estimated inputs. Both DNSPs also noted that the calculation of capex for poles and brackets and luminaires is highly volatile in practice, when compared to a relatively smooth benchmark calculation. Furthermore, CitiPower and Powercor stated:

> With values of half a million being experienced in 2005 it is plausible that the higher values calculated in the benchmark years are plausible.[76]

United Energy noted that the increase capex for poles and brackets from $448 905 in 2014 to $1 062 444 in 2015 is driven by an increase in the volume of poles and brackets to be replaced. United Energy also stated that forecast public lighting pole

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74 AER, *Energy Efficient Public Lighting Charges—Victoria (Final)*, February 2009.

75 This ensures consistency between the treatment and assessment of forecast capex for standard control services and alternative control services by the AER.

76 Email from CitiPower and Powercor to AER staff on 5 March 2010.

replacements are derived from the outputs of its Asset Replacement Model. This model forecasts on the basis of inputs including the age profile of public lighting poles, assumed asset life and a condition assessment which results in a spread or smoothing of the (pole and bracket) replacements.[77]

Jemena noted that the increase in capex for poles and brackets from $17 245 in 2010 to $79 483 in 2011 was due to plans for 86 pole replacements in 2010. Further, Jemena noted that forecast 2010 capex represents a simple split (3 per cent allocated to ‘poles and brackets’ and 97 per cent allocated to ‘luminaires’) of the total forecast replacement capex for 2010.[78]

SP AusNet calculated its capex for poles and brackets as a function of the need to replace poles at the end of their physical life. SP AusNet advised that these assets have a 30 year life and a large portion of SP AusNet's poles and brackets are approaching that age. SP AusNet estimates that approximately 3 per cent will require replacement each year.[79]

SP AusNet also stated that councils will not be funding 100 per cent of T5 luminaires’ installation up-front. For each T5 light that replaces an MV80 luminaire in SP AusNet's network, SP AusNet will be contributing $94.55 of the total cost.[80]

Submissions on DNSP regulatory proposals

The AER notes that there were no submissions on this issue.

AER considerations

The AER has assessed the expenditure profiles for each of the Victorian DNSPs including conducting an assessment of the reasonableness of the cost inputs for capex. The AER rejects the forecasts for capex requirements on the basis that various cost inputs used to derive overall capex requirements do not represent efficient cost inputs of providing public lighting services. Furthermore, as discussed in more detail in the following sections, the AER considers that several of the Victorian DNSPs’ total capex forecasts do not reflect the efficient costs of providing public lighting services over the forthcoming regulatory control period, when compared to historical actual capex requirements.

Labour and elevated platform vehicle rates

The AER considers that the 2010 base labour rate used by CitiPower, Powercor and SP AusNet does not represent fair and reasonable labour costs, and should be amended to the labour rates in section 19.7.1 of this chapter. The AER has escalated these by the labour escalation rates provided in appendix K of this draft decision and section 19.7.1 of this chapter.

Further, the AER rejects SP AusNet’s proposed elevated platform vehicle costs of $40.00 and $72.28 for urban and rural areas, respectively. The AER considers that SP AusNet did not provide the AER with sufficient grounds for it to accept their proposal, particularly regarding why there is a significant forecast increase in costs relative to those established in the AER’s 2009 final decision. Accordingly the AER

77 Email from United Energy to AER staff on 5 March 2010.
78 Email from Jemena to AER staff on 5 March 2010.
79 Email from SP AusNet to AER staff on 5 March 2010.
80 Email from SP AusNet to AER staff on 5 March 2010.

proposes to replace SP AusNet's elevated platform vehicle cost inputs with the rates provided in the AER's 2009 final decision and which has also been adopted by the other Victorian DNSPs. These rates are:

- $35.00—cost of elevated platform vehicle (per hour) for urban MV80 and T5 lights
- $45.00—cost of elevated platform vehicle (per hour) for rural MV80, T5, and S-HP lights.[81]

Forecast volumes for replacement of luminaires, poles and brackets

The AER also notes significant increases in public lighting capex forecast by SP AusNet and United Energy, in relation to the number of poles and brackets and luminaires to be replaced over 2011–15.

In particular, the AER notes that SP AusNet's total capex requirement has tripled from $5.1 million in the current regulatory control period to $15.6 million for the forthcoming regulatory control period. The AER notes that this is driven by the following proposed capex requirements for the forthcoming regulatory control period:

- total capex for existing luminaires of $4.5 million (an increase of 201 per cent from the current regulatory control period)
- total capex for poles and brackets of $8.5 million (an increase of 172 per cent from the current regulatory control period).[82]

The AER observes that SP AusNet's proposed capex increases are largely driven by the forecast number of luminaires, poles and brackets to be replaced during the forthcoming regulatory control period. SP AusNet has stated that a large portion of these assets are approaching the end of their life, and that the capex was calculated as a function of the need to replace these assets. Despite this, the AER considers that SP AusNet has not provided sufficient evidence or justification for the proposed increase in capex on luminaires, poles and brackets for 2011–15, particularly given the magnitude of the capex requirements proposed.

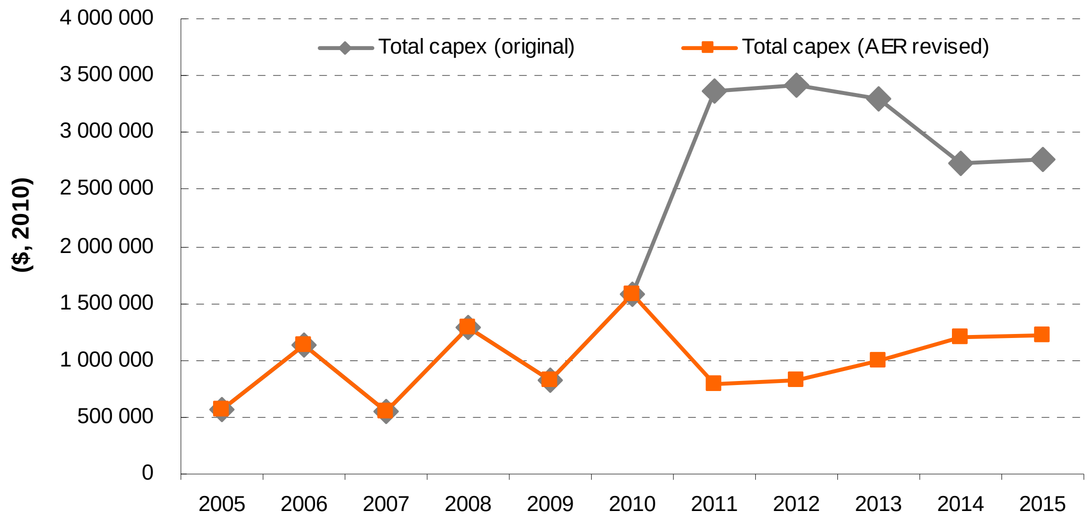
Accordingly, the AER has no grounds to accept SP AusNet's proposed volumes of luminaires, poles and brackets to be replaced over 2011–15, and therefore rejects SP AusNet's proposed capex requirements for the forthcoming regulatory control period. In line with this, the AER has reduced SP AusNet's proposed volumes of poles and brackets and luminaires to be replaced over the forthcoming regulatory period by 50 per cent. In doing this, the AER notes that SP AusNet's capex requirements for the 2011–15 are revised to:

- $1.3 million in capex for replacement of existing luminaries
- $4.1 million in capex for replacement poles and brackets.

81 AER, *Energy Efficient Public Lighting Charges—Victoria (Final)*, February 2009, p. 40.
82 SP AusNet, *EDPR 2011–15—public lighting model*, November 2009 (updated in March 2010).

As shown by figure 19.7, the AER notes that combined with other adjustments to SP AusNet's public lighting model, these revised figures provide capex forecasts that are more in line with historic actual capex.

Figure 19.7 SP AusNet's total capex, proposed versus draft decision ($, 2010)



Source: AER analysis.

The AER also observes that United Energy's proposed $1.1 million in capex on poles and brackets for 2015 represents a substantial increase when compared with the proposed capex for 2011 to 2014 ($0.29 million on average) and the historical annual capex from 2005 to 2009 ($0.26 million on average). The AER notes that this increase in capex is largely driven by the proposed volume of poles and brackets to be replaced in 2015, notably:

- 1007 poles and brackets in urban areas (compared to the annual average of 284 from 2011 to 2014)
- 192 poles and brackets in rural areas (compared to the annual average of 54 from 2011 to 2014).[83]

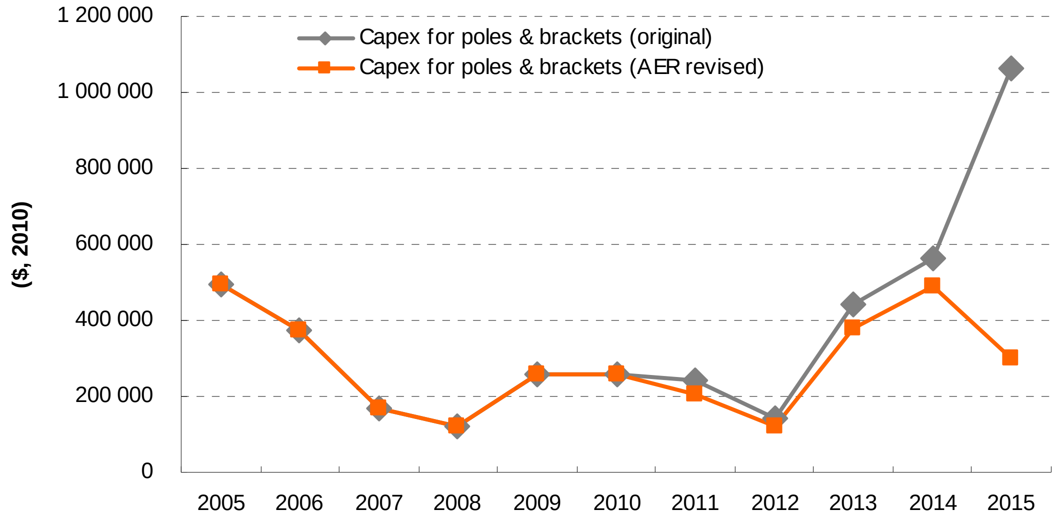
The AER notes that United Energy explained this proposed increase by stating that pole replacements are derived from the outputs of its Asset Replacement Model, which forecasts on the basis of inputs including the age profile of poles, assumed asset life and a condition assessment which results in a spread or smoothing of the (pole and bracket) replacements. However, the AER considers that United Energy has not provided sufficient evidence or justification to support this substantial increase in the volume of replacements in the final year of the forthcoming regulatory control period.

Accordingly, the AER rejects United Energy's proposed volumes of poles and brackets to be replaced over 2015. The AER has reduced United Energy's proposed volumes of poles and brackets to be replaced in 2015 to an amount equivalent to the average volume of forecast replacements over 2011 to 2014. In doing this, the AER notes that combined with other adjustments to United Energy's public light model, capex for poles and brackets in 2015 is revised from $1 062 444 to $298 402.

83 United Energy, *Regulatory Proposal 2011–2015—public lighting model*, November 2009.

As shown in figure 19.8, this revised capex figure for poles and brackets in 2015 is more in line with historic capex and the AER's revised capex for 2011 to 2014.

Figure 19.8 United Energy's capex for poles and brackets, proposed versus draft decision



Source: AER analysis.

After consideration of the forecast replacement volumes of luminaires, poles and brackets for the CitiPower, Powercor and Jemena, the AER considers the quantities of replacements proposed did not appear to be substantially different to the historic actual capex requirements. Accordingly, the AER did not revise these quantity forecasts.

Capex for energy efficient lights

In relation to SP AusNet's assertion that it funds $94.55 of the cost of T5 luminaires which replace MV80s, the AER understands that, in Victoria, where a council requests retrofitting a new type of public lighting asset, a DNSP is not required under its distribution licence or the Public Lighting Code to fund the capital cost for the new asset up front.

Any joint funding arrangements between DNSPs and councils for retrofitting T5 luminaires (or other new luminaire types) in place of existing luminaires, is a commercial decision for these parties. The funding costs do not form part of the public lighting model and regulated charges for public lighting alternative control services. Such arrangements would however be subject to the framework in place for negotiated services, discussed in section 19.9 of this chapter.

Therefore, the AER rejects SP AusNet's proposed capex for energy efficient lights and has removed its $94.55 funding from its capex proposal. This amendment has reduced SP AusNet's 2011–15 forecast net capex by $2.5 million. As a result of this, SP AusNet's T5 OMR charges have been reduced by $9.00 and $9.98 per annum for T5 (2x14 watt) and T5 (2x24 watt) energy efficient lights, respectively.

Proposed costs of poles and brackets

The AER also notes that CitiPower and Powercor each proposed pole and bracket costs of $3125 which is substantially above their existing cost of $500 taken from the ESCV's 2004 decision and the AER's 2009 decision, adopted by the other DNSPs.

As CitiPower and Powercor have not provided substantive evidence to justify this large cost variance, the AER rejects the proposed cost of $3125 for poles and brackets in 2010. Accordingly, the AER proposes to adopt a cost of $500 in line with the ESCV's 2004 decision and AER's 2009 decision and adopted by the other DNSPs.

19.8.4 Weighted average cost of capital

Victorian DNSP regulatory proposals

The Victorian DNSPs proposed weighted average cost of capital (WACC) for the forthcoming regulatory control period, is set out in table 19.42, which also includes the current regulatory control period WACC for comparison purposes.

Table 19.42 Victorian DNSP real pre-tax WACC, 2006–10 and proposed 2011–15 regulatory control periods (per cent)

	2006–10	Proposed 2011–15
CitiPower	6.40	8.21
Powercor	6.30	8.21
Jemena	6.40	9.55
SP AusNet	6.40	8.65
United Energy	6.30	8.22

Source: Victorian DNSP regulatory proposals.

Submissions on DNSP regulatory proposals

Submissions on the cost of capital are set out in chapter 11 of this draft decision.

AER considerations

The AER has adopted the real pre-tax WACC for each DNSP as determined in the post-tax revenue model. Table 19.43 shows the real pre-tax WACC for each Victorian DNSP, to be applied to their respective public lighting RABs in the forthcoming regulatory control period.

Table 19.43 Draft decision, real pre-tax WACC (per cent)

	2011–15
CitiPower	7.46
Powercor	7.38
Jemena	7.44
SP AusNet	7.30
United Energy	7.46

Source: AER analysis.

19.9 Issues and AER considerations—other matters

19.9.1 Introduction of new lighting types during 2011–15 regulatory control period

Victorian DNSP regulatory proposals

At the time the Victorian DNSPs' regulatory proposals were lodged on 30 November 2009, only SP AusNet proposed a compact fluorescent light (CFL) charge. A CFL is an alternative to a T5 energy efficient luminaire. CFLs were considered as a replacement light for MV80s in the evaluation of low energy lights for minor road lighting, produced by the Victorian Sustainable Public Lighting Action Group (VSPLAG).[84].

Following the MAV's submission (see section 19.5), the AER asked the other Victorian DNSPs if they intended to propose a CFL charge. United Energy, CitiPower and Powercor considered provision of CFLs to be a negotiated service and advised that they would not propose a regulated charge under the public lighting model. Jemena responded with a proposed CFL charge and an additional T5 (2x24W) charge.

Submissions on DNSP regulatory proposals

The MAV requested that the AER advise of its ability to approve OMR charges for new public lighting technology, such CFLs, proposed after the commencement of the regulatory control period on 1 January 2011. This is discussed below.

AER considerations

The AER notes that, in September 2009, a Memorandum of Understanding (MOU) has been entered into between:

- Victorian DNSPs
- VicRoads
- Victorian Local Government Association
- Municipal Association of Victoria

[84] VSPLAG, *Evaluation of low energy lights for minor road lighting (Final)*, April 2009.

- Victorian Department of Sustainability and Environment.

This MOU relates to public lighting, and specifically sets out procedures for introducing new lighting technologies at any time in Victoria to meet environmental (and other) objectives.

The AER notes that its Framework and approach paper classified the alteration and relocation of existing DNSP public lighting assets, and the provision of new public lighting assets, as negotiated services—noting the regulatory arrangements under the ESCV's Public Lighting Code and Guideline 14, and that under these arrangements public lighting services can be provided by parties other than the DNSP, such as VicRoads and local councils, or other third parties.

The AER notes that 'new public lighting assets' in the context of the framework and approach, applied to assets constructed in new residential and commercial subdivisions by parties other than the DNSP. Under Victorian arrangements, these assets are (usually) vested to the Victorian DNSPs upon connection to the relevant electricity distribution network. The DNSP is then responsible for the associated operation, maintenance, repair and replacement of these assets under the Code. If the asset is not vested to the DNSP, then the relevant third party provider is responsible for the associated operation, maintenance, repair and replacement of these assets.

New technology public lighting assets that are constructed from the commencement of the regulatory control period on 1 January 2011 and not regulated as public lighting alternative control services under the AER’s distribution determination are considered by the AER to be 'new assets' and therefore subject to the AER's negotiating criteria and the relevant DNSP’s negotiating framework. Accordingly, councils and Victorian DNSPs can negotiate a charge for a new lighting technology that did not exist at the time of the relevant DNSP’s regulatory proposal or the AER's final distribution determination.

The AER notes that it is not empowered under the NER to consider or request ad-hoc proposals for public lighting charges where a distribution determination is already in force. The introduction of any new lighting technology during 2011–15 will therefore be on a negotiated basis. Chapter 3 sets out the approach to negotiated distribution services.

Accordingly, CFL charges have not been assessed by the AER as part of this draft decision.

19.9.2 Ownership of public lighting assets

In their public lighting models, the Victorian DNSPs have accounted for assets installed at 2001 in their RABs and public lighting assets added since then. Any assets that are vested or gifted to the Victorian DNSPs are owned and maintained by the Victorian DNSPs and rolled into their RABs at zero cost.

Submissions on DNSP regulatory proposals

In meetings with AER staff, and in their submission, SGC claimed that public lighting assets installed since 2001 are owned by municipal councils and therefore the OMR charge for 2011–15 should be reduced to reflect this.[85]

The basis for this claim is a 1993 letter from the former State Electricity Commission Victoria (SECV) which states:

> At present the public lighting tariff includes a component to recover the capital cost of public lighting assets, which are primarily financed by the SECV. As from the (sic) 1 May all new works associated with the provision of public lighting capital works will be 100% customer financed…[86]

SGC claimed that the 1993 letter dispels the notion that the Victorian DNSPs have ownership of public lighting assets in Victoria and that customers should not therefore be forced to fund the replacement costs for luminaires or poles and brackets which are periodically replaced by the Victorian DNSPs.

AER considerations

The AER's 2009 decision[87] and the ESCV's 2004 decision[88] rejected the claim by SGC that public lighting assets are owned by municipal councils. The ESCV's investigation determined that the financing of new public lighting installations by the customer, referred to in the 1993 SECV letter, did not recover any costs associated with the replacement of the public lighting assets in later years. Asset ownership was vested by the Victorian government to the DNSPs during electricity industry privatisation in the mid 1990s (that is, after the SECV's 1993 letter).

In any case, the AER has no role in determining the ownership of the assets vested at the time of privatisation. If municipal councils dispute asset ownership it would be appropriate for the councils to raise this with the Victorian government.

19.9.3 Contestability of public lighting

Submissions on DNSP regulatory proposals

As noted in section 19.5, Citelum queried whether the market in respect of public lighting (under the Victorian and NER framework) is contestable.

In its letter to the AER, Citelum has noted a number of matters including that the AER's Framework and approach paper for Victorian electricity distribution regulation stated:

> The AER considers that, having regard to the factors in section 2F of the National Electricity Law, there are no specific regulatory barriers to any party other than the Victorian DNSPs providing new public lighting assets and that

[85] Meeting between AER staff and SGC representatives, 2 March 2010; also stated in the submission by Streetlight Group of Councils, February 2010, pp. 1–3, pp. 6–9 and p. 24.
[86] Letter provided by SGC separately to AER, and excerpts as part of SGC submission.
[87] AER, *Energy Efficient Public Lighting charges—Victoria (Final)*, February 2009, p. 17
[88] ESCV, *Review of Public Lighting Excluded Service Charges, Final Decision*, August 2004, pp. 96–98

> customers seeking this service are likely to have some countervailing market power.[89]

The AER's Framework and approach paper for Victorian electricity distribution regulation also stated that:

> The AER's role in service classification only determines the manner in which a DNSP recovers the costs associated with the distribution services it provides — it does not determine the contestability of these services. For example, the AER's classification of a distribution service as a direct control service does not make any of the Victorian DNSPs the exclusive monopoly providers of the service. Likewise, the AER's classification of a distribution service as a negotiated distribution service does not, of itself, make the service contestable and open to supply by providers other than the Victorian DNSPs. Contestability is determined by legislation, the NER, or other regulatory instruments, and is beyond the control of the AER.[90]

Citelum also paraphrased clause 7.8.5.1 of the DNSPs' Service and Installation Rules (SIRs) as stating that:

> Public lighting is deemed an allowable piece of equipment to be mounted and connected to the distributor's assets.[91]

Citelum has asked the AER whether this clause is to the effect that a party other than a DNSP, such as Citelum, can provide public lighting services to municipal councils using existing distribution network assets such as wooden distribution poles.

AER considerations

The AER notes that the SIRs are an industry wide formal standard (but not a regulatory standard) that assists the Victorian DNSPs and other service provides to comply with regulatory and electricity supply obligations. They form the major part of the Victorian DNSPs' 'reasonable technical requirements' referred to in the Electricity Distribution Code and are set by the Victorian Service Installation Rules Management Committee.[92]

Clause 7.8.5.1 of the SIRs notes that 'agreement' between the Victorian DNSPs and other parties is required before equipment may be installed on a DNSP's pole.

The Public Lighting Code, which must be adhered to by customers and the Victorian DNSPs and observed by the AER, defines 'public lighting assets' as meaning:

> all assets of a distributor which are dedicated to the provision of public lighting, including lamps, luminaires, mounting brackets and poles on which fixtures are mounted, supply cables and control equipment (for example, photoelectric cells and control circuitry) but not including the distributor's protection equipment (for example fuses and circuit breakers).[93]

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89 AER, *Framework and approach paper*, May 2009, p. 49.

90 ibid., p. 16.

91 Citelum, Victorian electricity distributors, Service and Installation Rules 2005, pp. 7–50, http://www.victoriansir.org.au/sirs.html accessed on 5 May 2010.

92 Made up of representatives from each of the Victorian DNSP and at the time the SIR's were written, advisers from the Office of the Chief Electrical Inspector and National Electrical and Communications Association.

93 ESCV, *Public Lighting Code*, April 2005, p. 10.

In determining whether 'new public lighting assets' are contestable, clause 1.3 of the Code makes it clear that the Code only applies to public lighting assets owned by the Victorian DNSPs.

It would appear, therefore, that the installation of new assets is contestable under the Code. However, the AER notes that there are certain processes in place if alterations are to be made to existing assets. These are set out in clause 4.4 of the Code. For example, a customer must, among other matters, obtain the DNSP's approval of the person who undertakes this work.

Relevantly, clause 4.4 of the Code and the SIRs both require the agreement between the DNSP and the respective parties to replace one asset with another—in this case, an existing DNSP owned public light on a DNSP owned pole, with a 'new' energy efficient light, constructed and installed by a third party provider other than the DNSP.

Therefore, the AER understands that the replacement, relocation and alteration of existing assets and the installation of new public lighting assets are contestable under clause 4.4 of the Code. As discussed previously, such services are classified as negotiated services in this draft decision and would be subject to the AER's negotiating criteria and the relevant DNSP's negotiating framework.

19.9.4 Compliance with price control mechanism

Clause 6.12.1(13) of the NER requires that the AER's distribution determination include a decision on how compliance with the control mechanism for street lighting services is to be demonstrated.

Under the price cap control mechanism the OMR charge for public lighting services contained in this decision are the maximum prices the Victorian DNSPs can charge for that service in a regulatory year. Compliance with the control mechanism is to be demonstrated by the Victorian DNSPs through the annual pricing approval process and be consistent with this decision for the relevant regulatory year. The AER also notes that the OMR charges approved by the AER will be subjected to CPI adjustment for each year of the forthcoming regulatory control period. .

19.9.5 Information requirements

In anticipation of assessing the 2016–20 OMR charges and consistent with the AER's 2009 final decision, the Victorian DNSPs will be required to report actual capex expenditure between energy efficient luminaires and existing luminaires.

The AER raises this matter for DNSPs' information, noting it is not part of the constituent decisions under clauses 6.12.1(12) and (13). The information is provided to assist in the process for the 2016–20 regulatory control period.

These actions will ensure that only those councils choosing to install energy efficient public lighting in their municipalities will pay for that service.

This will enable the AER to assess the Victorian DNSPs' forecast of energy efficient luminaires capex for 2016–20 from the capex for other lighting types. Cross-subsidisation of OMR charges will be minimised through these requirements.

The AER anticipates specifying formal reporting requirements in a Regulatory Information Notice (RIN).

19.10 AER conclusion

The AER has assessed the public lighting expenditure forecasts and associated charges proposed by each of the Victorian DNSPs. The AER has assessed the forecast expenditure including conducting an assessment of the reasonableness of each of the labour and other cost inputs for opex and capex. The AER rejects the Victorian DNSPs' proposed public lighting OMR charges on the basis that the opex and capex inputs do not reflect the efficient costs of providing public lighting services over the forthcoming regulatory control period.

As set out in this chapter, the AER considers the labour cost inputs used in the proposed capex and opex forecasts do not represent efficient labour costs. The AER also rejects the proposed opex requirements for traffic management costs on the basis that these costs do not represent efficient costs. Further, the AER considers that the Victorian DNSPs have not provided sufficient evidence to support their proposed increases in capex from 2011 to 2015, noting that the forecast replacement volumes of poles and brackets and luminaires for existing public lighting assets for the forthcoming regulatory control period is materially inconsistent with historical actual replacement expenditure. The AER is of the view that the proposed capex increases do not represent an efficient capex requirement for the forthcoming regulatory control period. These forecasts are therefore rejected.

The Victorian DNSPs should provide further documentary evidence in their revised regulatory proposals to support expenditure forecasts, particularly in relation to capex for replacement of poles and brackets and luminaires. Further, the AER considers that the Victorian DNSPs should adopt the labour rates and other cost inputs for public lighting that the AER has endorsed in this draft decision.

In accordance with clause 6.12.1(12) of the NER, the control mechanism that will apply to the Victorian DNSPs' public lighting services is a cap on the charges for each year of the forthcoming regulatory control period. In accordance with clause 6.12.1(13) of the NER, the Victorian DNSPs' compliance with the control mechanisms for public lighting services is to be demonstrated through the annual pricing approval process.

19.10.1 AER conclusion on DNSPs public lighting operational expenditure

Table 19.44 shows the AER's draft decision total opex for each DNSP over the 2011–15 regulatory control period.

Table 19.44 Draft decision, total opex for 2011–15 ($, 2010)

	2011	2012	2013	2014	2015
CitiPower	1 904 494	1 936 187	1 960 233	1 982 792	1 996 090
Powercor	4 163 028	4 397 122	4 652 710	4 891 739	5 115 541
Jemena	1 987 975	2 013 377	2 043 334	2 073 315	2 091 429
SP AusNet	3 734 850	3 901 657	4 144 296	4 250 055	4 331 607
United Energy	3 114 035	3 123 612	3 133 189	3 142 766	3 152 343

Source: AER analysis.

19.10.2 AER conclusion on DNSP's public lighting capital expenditure

Table 19.45 sets out the AER's draft decision total capex for each DNSP over the 2011–15 regulatory control period.

Table 19.45 Draft decision, total capex for 2011–15 ($, 2010)

	2011	2012	2013	2014	2015
CitiPower	–784 373	–693 720	–33 169	65 163	64 942
Powercor	–1 482 887	–1 147 471	–607 093	172 392	171 844
Jemena	815 263	212 042	474 679	207 551	677 372
SP AusNet	796 929	816 139	1 003 397	1 205 125	1 217 639
United Energy	1 795 956	1 640 671	1 847 453	1 435 619	1 383 475

Note: Negative capex figures are due to customer contributions for replacing existing lights (MV80) with energy efficient lights (T5), being greater than the DNSP's capex for existing lights.

Source: AER analysis.

19.10.3 AER conclusion on DNSPs public lighting charges

Set out in tables 19.46 to 19.51 is the AER's draft decision public lighting charges for Victorian DNSPs over the 2011–15 regulatory control period. The AER has also set these charges out in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

Table 19.46 Draft decision public lighting charges, CitiPower, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	61.89	64.09	63.92	64.61	65.51
Sodium high pressure 150 watt	101.63	105.23	106.15	108.11	110.14
Sodium high pressure 250 watt	103.27	106.94	107.82	109.78	111.82
T5 2X14 watt	31.07	31.89	32.77	33.71	34.55
Fluorescent 20 watt	123.17	127.54	127.20	128.57	130.37
Fluorescent 40 watt	123.79	128.18	127.84	129.21	131.02
Mercury vapour 50 watt	87.89	91.01	90.77	91.74	93.02
Mercury vapour 125 watt	97.79	101.26	100.99	102.08	103.51
Mercury vapour 250 watt	86.75	89.83	90.57	92.21	93.93
Mercury vapour 400 watt	87.78	90.90	91.65	93.31	95.05
Mercury vapour 700 watt	129.09	133.68	134.77	137.22	139.77
Sodium high pressure 70 watt	131.21	135.87	135.51	136.97	138.88
Sodium high pressure 100 watt	103.66	107.33	108.27	110.27	112.35
Sodium high pressure 220 watt	103.48	107.16	108.04	110.00	112.04
Sodium high pressure 360 watt	105.34	109.08	109.98	111.97	114.06
Sodium high pressure 400 watt	113.60	117.64	118.60	120.75	123.00
Sodium high pressure 1000 watt	204.48	211.74	213.48	217.36	221.40
Metal halide 70 watt	202.39	209.57	209.02	211.26	214.22
Metal halide 100 watt	159.56	165.20	166.65	169.73	172.92
Metal halide 150 watt	160.57	166.26	167.71	170.81	174.03
Metal halide 250 watt	123.93	128.33	129.38	131.73	134.18
Metal halide 400 watt	123.93	128.33	129.38	131.73	134.18
Metal halide 1000 watt	184.86	191.43	193.00	196.50	200.16

Source: AER analysis.

Table 19.47 Draft decision public lighting charges, Powercor, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	40.26	43.07	51.46	50.13	49.96
Sodium high pressure 150 watt	72.01	75.36	79.83	79.57	80.26
Sodium high pressure 250 watt	74.59	78.11	82.85	82.41	83.05
T5 2X14 watt	27.33	28.02	28.79	29.46	30.02
Fluorescent 20 watt	111.91	119.75	143.07	139.35	138.89
Fluorescent 40 watt	111.91	119.75	143.07	139.35	138.89
Mercury vapour 50 watt	55.96	59.87	71.54	69.68	69.44
Mercury vapour 125 watt	54.35	58.15	69.48	67.67	67.44
Mercury vapour 250 watt	56.69	59.36	62.96	62.63	63.12
Mercury vapour 400 watt	65.64	68.74	72.91	72.52	73.09
Mercury vapour 700 watt	99.20	103.89	110.19	109.61	110.46
Sodium low pressure 90 watt	97.22	101.74	107.78	107.41	108.35
Sodium low pressure 180 watt	97.22	101.74	107.78	107.41	108.35
Sodium high pressure 400 watt	99.20	103.89	110.19	109.61	110.46
Incandescent 100 watt	111.91	119.75	143.07	139.35	138.89
Incandescent 150 watt	111.91	119.75	143.07	139.35	138.89
Metal halide 250 watt	99.20	103.89	110.19	109.61	110.46
Metal halide 400 watt	99.20	103.89	110.19	109.61	110.46

Source: AER analysis.

Table 19.48 Draft decision public lighting charges, Jemena, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	37.60	39.76	41.85	44.15	46.83
Sodium high pressure 150 watt	73.40	76.93	80.47	84.30	88.38
Sodium high pressure 250 watt	74.77	78.42	82.06	86.00	90.22
T5 2X14 watt	24.37	25.17	26.13	27.16	28.18
Fluorescent 20 watt	47.00	49.70	52.31	55.19	58.54
Fluorescent 40 watt	47.00	49.70	52.31	55.19	58.54
Fluorescent 80 watt	47.00	49.70	52.31	55.19	58.54
Mercury vapour 50 watt	47.00	49.70	52.31	55.19	58.54
Mercury vapour 125 watt	55.27	58.44	61.52	64.91	68.85
Mercury vapour 250 watt	71.78	75.28	78.78	82.56	86.62
Mercury vapour 400 watt	80.75	84.69	88.63	92.88	97.44
Sodium low pressure 90 watt	77.81	81.55	85.30	89.36	93.68
Sodium high pressure 50 watt	91.75	96.16	100.59	105.37	110.47
Sodium high pressure 100 watt	100.56	105.40	110.25	115.49	121.08
Sodium high pressure 400 watt	99.44	104.29	109.14	114.38	120.00
Sodium high pressure 250 watt (24 hours)	116.64	122.33	128.02	134.16	140.75
Metal halide 70 watt	96.63	102.18	107.55	113.48	120.36
Metal halide 100 watt	162.95	170.79	178.65	187.14	196.20
Metal halide 150 watt	162.95	170.79	178.65	187.14	196.20
Metal halide 250 watt	160.75	168.59	176.43	184.90	193.98
Incandescent 50 watt	47.00	49.70	52.31	55.19	58.54
Incandescent 100 watt	58.65	62.02	65.28	68.88	73.06
Incandescent 150 watt	73.32	77.53	81.60	86.10	91.33

Source: AER analysis.

Table 19.49 Draft decision OMR charges, SP AusNet, central region, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	34.88	36.45	37.65	39.04	40.51
Sodium high pressure 150 watt	72.96	75.92	78.63	81.54	84.29
Sodium high pressure 250 watt	73.87	76.87	79.61	82.54	85.32
T5 2X14 watt	30.11	31.30	32.28	33.70	35.00
T5 2X24 watt	34.55	35.86	36.96	38.50	39.92
Mercury vapour 50 watt	53.36	55.77	57.61	59.74	61.98
Mercury vapour 125 watt	51.27	53.58	55.35	57.39	59.55
Mercury vapour 250 watt	77.56	80.71	83.59	86.66	89.58
Mercury vapour 400 watt	80.52	83.78	86.78	89.97	92.99
Sodium high pressure 100 watt	78.06	81.23	84.14	87.24	90.19
Sodium high pressure 400 watt	104.90	109.15	113.05	117.20	121.15

Source: AER analysis.

Table 19.50 Draft decision public lighting charges, SP AusNet, north and east regions, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	38.55	40.26	41.61	43.12	44.71
Sodium high pressure 150 watt	82.18	85.50	88.59	91.86	94.93
Sodium high pressure 250 watt	81.57	84.86	87.91	91.15	94.19
T5 2X14 watt	32.93	34.22	35.30	36.83	38.22
T5 2X24 watt	37.46	38.86	40.06	41.71	43.23
Mercury vapour 50 watt	57.05	59.59	61.58	63.82	66.17
Mercury vapour 125 watt	57.05	59.59	61.58	63.82	66.17
Mercury vapour 250 watt	84.83	88.25	91.43	94.80	97.96
Mercury vapour 400 watt	87.28	90.80	94.07	97.53	100.78
Sodium high pressure 100 watt	87.93	91.48	94.79	98.29	101.58
Sodium high pressure 400 watt	115.83	120.50	124.84	129.43	133.75

Source: AER analysis.

Table 19.51 Draft decision public lighting charges, United Energy, 2011–15 ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	48.88	52.23	55.80	59.34	62.73
Sodium high pressure 150 watt	78.26	82.33	86.63	90.93	95.11
Sodium high pressure 250 watt	79.57	83.78	88.22	92.66	96.96
T5 2X14 watt	25.15	25.78	26.53	27.52	28.48
Fluorescent 2x20 watt	63.06	67.38	71.98	76.55	80.92
Fluorescent 3x20 watt	63.06	67.38	71.98	76.55	80.92
Mercury vapour 50 watt	72.35	77.30	82.58	87.82	92.84
Mercury vapour 125 watt	72.35	77.30	82.58	87.82	92.84
Mercury vapour 250 watt	72.41	76.24	80.28	84.32	88.23
Mercury vapour 400 watt	100.26	105.56	111.16	116.75	122.17
Mercury vapour 700 watt	100.26	105.56	111.16	116.75	122.17
Sodium high pressure 70 watt	107.05	114.38	122.20	129.95	137.38
Sodium high pressure 100 watt	86.09	90.56	95.29	100.03	104.62
Sodium high pressure 400 watt	100.26	105.56	111.16	116.75	122.17
Metal halide 70 watt	105.66	111.14	116.95	122.76	128.40
Metal halide 100 watt	105.66	111.14	116.95	122.76	128.40
Metal halide 150 watt	105.66	111.14	116.95	122.76	128.40
Metal halide 250 watt	107.42	113.10	119.10	125.09	130.89
Metal halide 400 watt	107.42	113.10	119.10	125.09	130.89

Source: AER analysis.

20 Other alternative control services

20.1 Introduction and background

Clause 6.2.2(a) of the National Electricity Rules (NER) divides direct control services into standard control services and alternative control services. On average, alternative control services (including public lighting services) make up 3 per cent of the Victorian DNSPs' revenues.[1]

This chapter sets out the AER's consideration of the Victorian DNSPs' alternative control (fee based and quoted) services pricing and how compliance with the pricing control mechanism is to be demonstrated by the Victorian DNSPs in the forthcoming regulatory control period.[2] The AER's consideration of the Victorian DNSPs' public lighting (alternative control) services pricing control mechanism is set out in chapter 19 of this draft decision.

Classification of the Victorian DNSPs' alternative control services is set out in chapter 2 of this draft decision.

Generally, alternative control services are services that were previously classified as 'excluded services' under the Essential Services Commission of Victoria's (ESCV) 2006 Electricity Distribution Price Review (2006 EDPR) and are provided at the request of a customer.

The Victorian DNSPs will be able to levy charges for alternative control services (fee based and quoted) over the forthcoming regulatory control period on the basis of the AER's final determination on pricing and control mechanisms for these services, which will be published by the end of October 2010. For fee based services the AER will determine a fixed fee, whereas for quoted services the AER will determine the labour rate and basis for materials charges which can then be applied to the particular work which needs to be performed.

The AER notes that this draft decision considers manual services only, and does not set prices for the Victorian DNSPs' remote metering services which are facilitated by the rollout of advanced metering infrastructure (AMI) in Victoria. The regulatory arrangements relating to the AMI rollout, and associated remote metering services charges, are set out in a legislative instrument that is separate to the NER. This is discussed further in section 20.4.1.

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1 This calculation was made using the Victorian DNSPs' 2008 regulatory accounting statements, being revenue from excluded services minus grid fees and unregulated services revenues.

2 Due to their variable nature, quoted services are provided on the basis of a quotation by a DNSP for the materials and labour time required to provide the service. Fee based services are more standardised services with less variation between customers, and are accordingly provided on the basis of a fixed fee.

20.2 Regulatory requirements

Clause 6.8.1 of the NER requires the AER to publish a Framework and approach paper in anticipation of every distribution determination, which amongst other things includes the control mechanisms to apply to direct control services.

Clause 6.2.5(b) lists the control mechanisms that the AER may apply to direct control services. One mechanism the AER may apply is a cap on the prices of individual services, under clause 6.2.5(b)(2) of the NER.

Clause 6.2.5(d) of the NER outlines the factors the AER must have regard to in deciding on the control mechanism to apply to alternative control services, being:

- the potential for development of competition in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.[3]

Under clauses 6.12.1(12) and 6.12.1(13) of the NER, the AER's distribution determination must set out a decision on the control mechanism for alternative control services and how compliance with that control mechanism is to be demonstrated.

Clause 6.12.3(c) of the NER provides that the control mechanisms to be applied in a distribution determination must be as set out in the Framework and approach paper.

20.3 AER Framework and approach paper

The AER's Framework and approach paper was published in May 2009 following consultation with stakeholders. It set out the form of control which would be applied to fee based and quoted alternative control services for the forthcoming regulatory control period:

> The AER will apply price caps in the next regulatory control period to the:
>
> - unit costs for the quoted services grouping of alternative control services, and
> - individual prices for all of the other alternative control services, with a limited building block approach being applied to the operation, repair, replacement and maintenance of public lighting assets.[4]

3 NER, clause 6.2.5(d).

The Framework and approach paper indicated that the AER would be utilising either a bottom up or top down approach in deriving the initial prices (or initial input prices) for each individual service.

A bottom up approach requires a DNSP to submit cost build up information relating to each individual service. A top down approach utilises historical audited regulatory account information to derive an appropriate escalation mechanism which would be applied to existing prices.[5]

The Framework and approach paper stated that after setting the initial price (or input price for quoted services) for 2011, for the remaining years of the forthcoming regulatory control period the AER would establish a price path for the price cap utilising a CPI—X basis of escalation.[6]

The price cap formula for the individual alternative control services set out in the Framework and approach paper is reproduced below:

$p_t \leq p_{t-1} \times (1+CPI_t) \times (1-X)$

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";

p_t is the price cap for each individual alternative control service in regulatory year "t";

CPIt is calculated as follows:

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

X to be determined using the building block approach.[7]

4 AER, *Framework and approach paper for Victorian electricity distribution regulation, CitiPower, Powercor, Jemena, SP AusNet and United Energy, Regulatory control period commencing 1 January 2011*, May 2009, p. 82.
5 AER, *Framework and approach paper*, p. 80.
6 ibid.
7 ibid., p. 141.

20.4 Summary of Victorian DNSP regulatory proposals

20.4.1 Background and service classification issues

The Framework and approach paper allowed the Victorian DNSPs some discretion in utilising bottom up and top down approaches to calculate proposed prices for alternative control services in the 2011–15 regulatory control period:

> The AER recognizes that a bottom up approach to price setting is likely to be more involved, and entail higher administrative costs for DNSPs than a top down approach, although it may result in more cost reflective prices. Accordingly, the AER intends to require DNSPs to prepare initial prices for those services that have the highest number of transactions and levels of revenue on a bottom up basis. Initial prices for other services will be set on a top down basis.[8]

The Victorian DNSPs have taken differing approaches to calculating proposed prices, varying between a bottom up build up of the prices of all alternative control fee based services or calculating prices using a top down approach with current prices as a starting point. The Victorian DNSPs have also used different approaches in building up input costs for services, for example some DNSPs have used actual input costs (labour, materials) and times taken to perform services, while others have made calculations based on external contractor prices where services are performed under contract. Section 20.7 provides an outline of each DNSP's approach to calculating proposed charges.

A number of the Victorian DNSPs have proposed to cease providing certain services which are being superseded by new technology or regulatory changes, and some DNSPs have proposed new alternative control services. For example, United Energy proposed the provision of 'possum guards' as a new fee based service.

Fee based and quoted alternative control services provided by the Victorian DNSPs will be subject to some changes from the beginning of the forthcoming regulatory control period. Some of the changes occurring were proposed by the DNSPs, for example service classification changes, moving services between fee based and quoted classifications, or where a DNSP has identified that a service is no longer required. In other cases, new services which were either previously not provided, or previously unregulated, will become alternative control services in the forthcoming regulatory control period. Classification of the Victorian DNSPs’ alternative control services is set out in chapter 2 of this draft decision. Appendix B of this draft decision lists the services provided by the DNSPs and the AER's classification of these services.

It is noted that a number of former fee based alternative control services have in this draft decision been reclassified by the AER as quoted services, for example temporary cover of low voltage mains services. Consequently the Victorian DNSPs have not provided information to the AER on the labour rates and terms of supply applicable to a number of these services, and in a form that would enable the AER to appropriately assess and compare rates and terms of supply across the range of services and DNSPs. Accordingly, the AER has not approved labour rates and terms of supply for all

8 ibid., p. 81.

quoted services in this draft decision, and the DNSPs will be required to submit labour rates and terms of supply for those quoted services in their revised proposals, for consideration in the AER's final decision. This matter is discussed further in section 20.6.

New connections requiring augmentation works will be classified as standard control services in the forthcoming regulatory control period, with any additional costs being covered by customer contributions, subject to ESCV Guideline 14—Provision of Services by Electricity Distributors (Guideline 14). This is discussed further in chapter 2 of this draft decision which sets out the AER's approach to service classification for new connections requiring augmentation works.[9] Accordingly, the AER has not approved prices for new connections requiring augmentation works in this draft decision. However, prices for standard / routine connection services, which are classified as fee based alternative services, have been approved in this draft decision.

In their regulatory proposals, several of the Victorian DNSPs proposed service classifications contrary to the Framework and approach paper classifications. For example, CitiPower, Powercor and Jemena proposed that routine new connection services be reclassified as standard control services.[10] As discussed in chapter 2, the AER has not accepted this proposal and has classified standard / routine connection services as alternative control services.

A number of changes to alternative control services will occur due to the rollout of AMI across Victoria over the forthcoming regulatory control period. As a result of the AMI rollout, some services will become redundant, others will reduce in price due to the service being provided remotely instead of manually, and some new services related to AMI meters will emerge. The regulatory arrangements relating to the AMI rollout are set out in an August 2007 Order in Council made by the Victorian Governor in Council under sections 15A and 46D of the *Electricity Industry Act 2000*. An amending Order in Council was made on 25 November 2008 (the ‘revised Order’). Clause 3 of the revised Order requires that certain metering services (which the AER considers includes new remote services, such as remote energisation and remote special reads) will continue to be regulated as 'excluded services' during the forthcoming regulatory control period.[11] In the current regulatory control period,

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9 The DNSPs will recover the costs of new connections requiring augmentation works in accordance with the weighted average price cap (WAPC) for standard control services, as well as via customer contributions, as provided for in clause 6.21.2 of the NER. The amount of customer up-front financial contributions for new connections requiring augmentation works will be regulated and calculated in accordance with the relevant provisions of ESCV Guideline 14 (or its successor instrument). See chapter 2, section 2.6.1 for more detail.

10 CitiPower, *Regulatory Proposal 2011 to 2015*, 30 November 2009, pp. 13–16; Powercor, *Regulatory Proposal 2011 to 2015*, 30 November 2009, pp. 14–17; Jemena, *Regulatory Proposal 2011–15*, 30 November 2009, pp. 47–49.

11 This refers to metering services that would otherwise be a regulated service under the revised Order but, as at 31 December 2008, were excluded services under the Victorian Electricity Supply Industry Tariff Order 2005.

excluded services were regulated under the Victorian DNSPs' distribution licences and the ESCV's Guideline 14.[12]

Accordingly, the AER will regulate the new services that are facilitated by AMI (including all remote services) under the Victorian DNSPs' distribution licences and Guideline 14.[13] The AER expects that such prices for remote metering services, which when the AMI rollout is completed will largely replace similar manual services, will be a fraction of the price of equivalent manual services, due to the minimal labour required to perform a remote service through an AMI meter.

For most alternative control services currently provided, the Victorian DNSPs' prices have not been amended or escalated for some time. The ESCV's 2006 EDPR allowed some price increases for new connection services to provide for the costs of installing interval meters as part of the ESCV's interval meter rollout program.[14] Prices for other alternative control services have not been adjusted by the ESCV in previous regulatory determinations except in relation to the introduction of the Commonwealth Goods and Services Tax in 2000. The Victorian DNSPs did not provide any information on the original basis and methodology used to set alternative control services prices when economic regulation of these services by the Office of the Regulator General[15] commenced in the mid 1990s.

20.4.2 Regulatory proposals

The following sections summarise the proposals made by the Victorian DNSPs, and draft decision service classification changes which affect the DNSPs' proposed alternative control services.

CitiPower and Powercor

Service and service classification changes

CitiPower and Powercor both proposed a number of changes to service classification within their regulatory proposals. The AER's consideration of service classifications is provided in chapter 2.

Service classification changes in this draft decision compared to the AER's Framework and approach paper classifications that affect CitiPower's and Powercor's proposed alternative control services include:

- standard connections for new connections to be classified as a fee based alternative control service for customers under 100 amps, and a quoted service for customers over 100 amps

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12 Essential Services Commission of Victoria (ESCV), *Electricity Industry Guideline No. 14—Provision of Services by Electricity Distributors—Issue 1*, April 2004.

13 The AER notes that Jemena proposed charges for certain remote services as part of its regulatory proposal, and indicated to the AER that it would be in a position to provide these remote services to customers with AMI meters in May 2010. The AER will regulate these services via the distribution licences and Guideline 14, and accordingly the remote services have not been considered as part of this draft decision.

14 Essential Services Commission of Victoria (ESCV), *Electricity Distribution Price Review 2006-10 October 2005, Final Decision,* Volume 1, October 2005, p. 589.

15 The Office of the Regulatory General was the predecessor to the ESCV.

- location of underground services (that is, 'dial before you dig') to become a standard control service
- reserve feeder, which involves operating and maintaining a second source of supply to a customer's premises, to be classified as a fee based alternative control service
- photovoltaic (PV) installation inspection, which was not classified in the Framework and approach paper, to become a fee based alternative control service
- damage to overhead service cables caused by high load vehicles to become a quoted alternative control service
- high load escorts, involving lifting of overhead lines, to become a quoted alternative control service.

Other changes to the services provided in 2010 include:

- special meter read after hours—service will not be provided (business hours only)
- time switch adjust—service will no longer be provided due to the very limited number of service requests in recent years, and because the AMI rollout makes this service redundant.[16]

Fee based services

To determine the prices for fee based alternative control services, CitiPower and Powercor both provided a cost build up model for their proposed services. The build up methodology is discussed in section 20.7. Proposed prices are set out in appendix O.

As part of their proposed control mechanism for fee based services, CitiPower and Powercor proposed individual prices for each year of the forthcoming regulatory control period, which varied between each service and year. CitiPower and Powercor did not propose a price path based on a CPI–X form of control as set out in the AER's Framework and approach paper.

Quoted services

CitiPower and Powercor proposed to provide the following quoted services:

- emergency recoverable works—business hours (BH) and after hours (AH)
- damage to overhead service cables caused by high load vehicles—single phase—BH and AH
- damage to overhead service cables caused by high load vehicles—multi phase—BH and AH

[16] As set out below, SP AusNet notes that any registered electrician can provide switching services. SP AusNet, *Electricity Distribution Price Review, Regulatory Proposal*, November 2009, pp. 372–373.

- high load escort—BH and AH.[17]

Unlike charges for fee based services, charges for quoted services are calculated on a case by case basis according to the specific needs of the customer, and the quantities of labour and materials required. CitiPower's and Powercor's proposed hourly rates for quoted services are summarised in appendix O.

CitiPower and Powercor determined costs for each of their quoted services by:

- identifying the tasks involved in performing the services
- estimating the average time required to undertake each service
- identifying the type and number of personnel required to undertake each task, based on the skills required
- calculating a labour rate for each type of personnel required.[18]

CitiPower and Powercor did not propose materials costs for their quoted services.

CitiPower's and Powercor's proposed control mechanism for quoted alternative control services is for price caps on proposed labour and material rates in 2011, and a CPI–X adjustment to the labour and material rates for 2012–15, where X is zero.[19] However, CitiPower and Powercor also proposed that their 2011 labour rate be escalated by labour escalators determined by their consultant BIS Schrapnel.[20]

Jemena Electricity Networks

Service and service classification changes

Draft determination classification changes from the AER's Framework and approach paper classifications that affect Jemena Electricity Networks' (Jemena) proposed alternative control services include:

- covering of low voltage mains to become a quoted alternative control service for the forthcoming regulatory control period
- standard connections for new connections to be classified as a fee based alternative control service for customers under 100 amps, and a quoted service for customers over 100 amps.

Jemena's regulatory proposal identified a number of new services which will become available due to the AMI rollout in Victoria, including:

- remote special meter read
- remote re-energisation

[17] CitiPower, *Regulatory proposal*, p. 386; Powercor, *Regulatory proposal*, p. 392.
[18] CitiPower, *Regulatory proposal*, p. 385; Powercor, *Regulatory proposal*, p. 387.
[19] CitiPower, *Regulatory proposal*, p. 385; Powercor, *Regulatory proposal*, p. 391.
[20] The AER's consideration of BIS Shrapnel's labour escalation rates is provided in appendix K.

- remote de-energisation
- remote meter configuration.[21]

As discussed in section 20.4.1, the revised Order requires that the AER regulate such remote services as 'excluded services,' being under the distribution licences and the ESCV's Guideline 14. As remote services are to be regulated as excluded services, the AER has not classified these remote metering services and has not considered remote meter services as part of this draft decision.

Jemena's regulatory proposal identified a number of services for which it has a separate charge in the current regulatory control period, which it proposed to consolidate into two general alternative control service charges:

- Temporary cover of low voltage mains—to incorporate current services of: cover service cable; second and subsequent month's rental of covers-service wire; cover low voltage mains-2 wire; second and subsequent month's rental of covers-2 wire; cover low voltage mains-all wires; second and subsequent months of rental of covers, all wires.
- Meter test—to incorporate current services of: retest of types 5 and 6 meter installations for first tier customers with annual consumption>160 MWh/annum; single phase meter test-first meter; single phase meter test-second and subsequent meters; multi phase meter test-first meter; multi phase meter test-second and subsequent meters.[22]

In addition to these changes, Jemena separated its existing recoverable works charge into six categories of quoted services. Terms for each quoted service are provided in appendix O.

Jemena identified a new charge for a wasted service vehicle visit, which was previously charged at the same rate as a service vehicle visit. A wasted service vehicle visit fee applies when a customer or contractor requests a service vehicle, but for reasons that are not Jemena's fault, when the vehicle arrives the customer or contractor is not ready for the service vehicle, or it is no longer required.[23] Jemena also identified a new charge for manual energisation of new premises, which was previously charged at the same rate as fuse insertion.

Jemena has also re-named a number of alternative control services for the forthcoming regulatory control period:

- re-energisation after de-energisation for non-payment will be named temporary disconnect/reconnect for non-payment
- fuse removal will be named manual de-energisation—existing premises

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[21] Jemena, *Regulatory proposal*, p. 220.
[22] ibid., p. 220.
[23] ibid., p. 235.

- fuse insertion will be named manual re-energisation—existing premises.

Fee based services

Jemena provided a bottom up cost model which it used to calculate its proposed prices for fee based alternative control services. The model was applied to all Jemena's proposed fee based alternative control services except for metering data provider services for unmetered supplies with type 7 metering installations and supply enhancement at customer request-reserve feeder, for which calculated prices are based on a top down approach.[24] Jemena's proposed prices for its fee based alternative control services are set out in appendix O.

Jemena proposed a price path for its bottom up fee based alternative control services, where each year charges are adjusted by (1+CPI)(1–X), where X reflects the escalation of cost inputs to the service in real terms. In contrast to the CPI–X form of control set out in the AER's Framework and approach paper, Jemena proposed a matrix of X factors for each year of the forthcoming regulatory control period. For its top down services Jemena proposed prices be adjusted each year by (1+CPI)(1–X), where X is equal to zero. Jemena proposed the same form of price control be applied to its reserve feeder service. Jemena's proposed matrix of X factors is reproduced in appendix O.

Quoted services

Jemena proposed the following quoted services for the forthcoming regulatory control period:

- damage to overhead service cables caused by high loads—involving restoration of overhead service cables pulled down by vehicles transporting high loads
- high load escort—lifting of overhead lines
- rearrangement of network assets at customer request (excluding alteration and relocation of existing public lighting services)
- supply enhancement at customer request—elective underground service.

In developing its proposed rates for quoted services, Jemena calculated a number of different labour rates for specific tasks, and proposed all materials be charged at cost.[25]

Jemena proposed a matrix of X factors to apply to its labour rates over the forthcoming regulatory control period, set out in table 20.1. Jemena did not propose any materials costs for its quoted services.

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24 ibid., p. 215. Meter data provider services for unmetered supplies with type 7 metering installations are dealt with under clause 6 of the AMI Order in Council. This draft determination does not approve charges for unmetered supplies, these are approved under the annual tariff approval process. The AER notes that the Framework and approach paper indicated unmetered supplies would be an alternative control service, however this is incorrect.

25 ibid., p. 242.

Table 20.1 Jemena proposal—indicative prices for the forthcoming regulatory control period ($, 2010)

Year	2011	2012	2013	2014	2015
Unit rate per man hr—BH	94.0	96.6	99.2	101.8	104.3
Unit rate per man hr—AH	122.3	125.5	129.0	132.3	135.5
X (per cent)	–2.4	–2.6	–2.7	–2.6	–2.4

Source: Jemena, *Regulatory proposal*, p. 243.

SP AusNet

Service and service classification changes

Draft decision classification changes from the AER's Framework and approach paper classifications that affect SP AusNet's proposed alternative control services include:

- covering of low voltage mains to become a quoted alternative control service
- elective undergrounding to become a quoted alternative control service
- damage to overhead service cables caused by high load vehicles to become a quoted alternative control service.

Other changes to alternative control services proposed by SP AusNet included:

- low voltage meter conversion (type 6 to type 5) will no longer be charged as a separate service, SP AusNet will apply a service truck visit fee to this service
- switching services will no longer be provided, as SP AusNet considers this service can be provided by any registered electrician
- provision of service fuses will no longer be provided, as this service is no longer requested by customers.[26]

Fee based services

SP AusNet used an incremental cost model, based on historical costs, to calculate its proposed prices for field officer visits, new connections and service truck visits. All other proposed fee based service prices are based on a top down adjustment of current (2010) prices. SP AusNet's proposed prices for its fee based alternative control services and terms for quoted services are set out in appendix O.

SP AusNet proposed the following price path for its fee based alternative control services to apply for each year of the forthcoming regulatory control period:

$P_t \leq P_{t-1}(1+CPI)(1-X)$ where $X = 1$ per cent.[27]

[26] SP AusNet, *Regulatory proposal*, pp. 372–373.
[27] ibid, p. 395.

Quoted services

SP AusNet proposed the following quoted services for the forthcoming regulatory control period:

- temporary cover of low voltage mains
- elective underground servicing
- service cable pulled down by high loads.

SP AusNet's regulatory proposal stated a typical price for each of its quoted services, based on the average times and rates applied for each service.[28] Table 20.2 provides a summary of the typical prices, labour and materials required for these quoted services.

Table 20.2 SP AusNet proposal—alternative control quoted services ($, 2010)

Service	Indicative price 2011	Cost items to determine total charge
Temporary cover of LV mains	1 171	Labour, materials and traffic management
Elective underground servicing	3 382	Survey, trenching, boring, conduit, cable, labour, motor vehicle, plant and equipment and minor materials
Service cable pulled down by high loads	1 108	Labour, materials and service trucks

Source: SP AusNet, *Regulatory proposal*, pp. 386–391.

SP AusNet proposed differing labour rates for a number of classifications, including:

- general line workers
- line workers with vehicle and equipment
- cover design services provided by drafting officers
- technical officers
- engineers.

SP AusNet also proposed labour rates for tasks required to perform some unregulated and negotiated services. The AER has not considered these proposed labour rates, as prices for unregulated and negotiated services are not set by the AER through its regulatory determination for distribution services. The regulatory arrangements for negotiated services are discussed in chapter 3 of this draft decision.

SP AusNet proposed that materials charges would be recovered from customers at cost.

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28 ibid., pp. 386–391.

SP AusNet did not propose a price path or control mechanism to apply to its quoted services prices for 2012–15.

United Energy

Service and service classification changes

United Energy proposed the following changes to the supply arrangements for its alternative control services:

- provision of possum guards— United Energy advised that this service is necessary for customers with private electricity assets that require protection from damage caused by possums. United Energy also advised that this service can range from putting sleaves on service lines to stop possums from walking along them to more complex installations for industrial customers where other types of preventative equipment is required. However, United Energy did not propose a service classification for provision of possum guards.

- the charges for winter tariff inspections and reverse cycle air conditioning tariff inspections have been consolidated into the charge for field officer visits.[29]

The AER considers that United Energy's proposed provision of possum guards service is contestable, as it is not necessary that a DNSP provides the service, as the materials are not specialised and the electrical assets involved are private. Accordingly, the AER has not approved a charge for the provision of possum guards as part of its draft decision.

United Energy also proposed charges for security lighting installations and meter provision for first tier customers consuming more than 160 kWh per annum. The AER considers that these services are contestable, and accordingly has not approved a charge for these services as part of this draft decision.

As part of its regulatory proposal, United Energy proposed charges for meter data services for all meters. Cost recovery for meter data services was provided as part of the AER's AMI determination in October 2009.[30] Consequently, the AER has not approved United Energy's proposed charges for meter data services.

Fee based services

United Energy based its proposed prices for fee based alternative control services on its external contractor's prices, plus United Energy's additional shared costs. Further details and analysis of United Energy's contracting arrangements for alternative control services are provided in section 20.7 of this chapter.

United Energy's proposed prices for its fee based alternative control services are set out in appendix O.

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[29] United Energy, *email to AER staff*, 12 February 2010.

[30] AER, *Final determination—Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications*, October 2009.

United Energy proposed a CPI escalation on proposed 2011 prices as its form of control for fee based services.[31] United Energy proposed the escalation be applied annually to ensure that the prices are adjusted in line with its external contractor charges.[32] Accordingly the price path proposed by United Energy is equal to (1+CPI)(1-X), where X is equal to zero.

Quoted services

United Energy's regulatory proposal specified that certain sub-classifications of services were to be recoverable works (quoted services), including:

- elective underground services, varying according to phases, length of line, whether the installation is new or existing, and whether it is provided in business or after hours

- new connection services, varying according to whether United Energy is or is not the responsible person, and whether it is provided in business or after hours.[33]

United Energy did not submit any labour or material rates for its proposed quoted services.

20.5 Summary of submissions

The AER received no submissions dealing specifically with alternative control services, however a submission on another matter received from the Energy Users Coalition of Victoria (EUCV) commented on the issue of wages growth:

> Overall, at most the AER should only allow for wages growth which is [no] higher than the average for sector over the long term. To allow for the wages growth in excess of CPI, is forcing consumers to pay a premium and which does not recognise the benefits of productivity. [34]

20.6 Consultant review

The AER engaged Impaq Consulting (Impaq) to assist its review of the proposed charges for alternative control services, in particular the inputs of hourly labour rates, materials and times taken to perform the services. Impaq has experience and expertise in the benchmarking of industry charge out rates, reviewing excluded service charges for metering, calculating excluded service costs and charges for DNSPs, as well as reviewing cost inputs in previous distribution price reviews. Impaq also reviewed the inputs into public lighting services, which are considered in chapter 19 of this draft decision. A public version of Impaq's report is available on the AER's website, www.aer.gov.au.

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[31] AER, *file note of meeting with United Energy*, 23 February 2010.
[32] United Energy, *email to AER staff*, 16 March 2010.
[33] United Energy, *Regulatory proposal, Appendix C-2*, pp. 30–33.
[34] Energy Users Coalition of Victoria, *Australian Energy Regulator Victorian Electricity Distribution Revenue Reset Applications from CitiPower, Jemena, PowerCor, SP Ausnet and United Energy—A response by Energy Users Coalition of Victoria*, February 2010, p. 32.

20.6.1 Fee based services

As outlined above, due to the different methodologies applied by the Victorian DNSPs in calculating their alternative control service costs and prices, Impaq's recommendations for fee based services were limited to the inputs used by CitiPower, Powercor and Jemena. However, the AER's review of SP AusNet's and United Energy's proposed alternative control services prices was informed by Impaq's findings and recommendations on input costs and times, which provided a benchmark from which to consider SP AusNet's and United Energy's proposed prices.

For fee based services, Impaq focussed its review on seven services that are frequently requested and generate the bulk of alternative control services revenue. The 'top seven' services contribute to over 70 per cent of each DNSP's total revenue earned from alternative control services. The top seven services are:

- routine (or standard) new connections
- field services officer visits
- reconnection/disconnection
- service vehicle visits
- meter equipment tests for various meter types
- temporary cover of low voltage mains[35]
- conversion from coincident to independent disconnection.

While Impaq's report is limited to the top seven services, the AER has used Impaq's advice on electricity industry labour rates and times taken to perform alternative control services to inform its review of all proposed fee based alternative control services prices.

Labour rate inputs

CitiPower's, Powercor's and Jemena's hourly labour rate inputs to fee based services were calculated on different bases, varying depending on the inclusion of on-costs, overheads and margins. In order to compare the inputs among the Victorian DNSPs and those in other jurisdictions, Impaq calculated equivalent charge out rates for each labour input.[36] The equivalent charge out rates were then broken down and each component of the hourly rates was compared among the DNSPs. Impaq also compared CitiPower's, Powercor's and Jemena's proposed labour rates against publicly available information on equivalent approved labour rates from the following sources:

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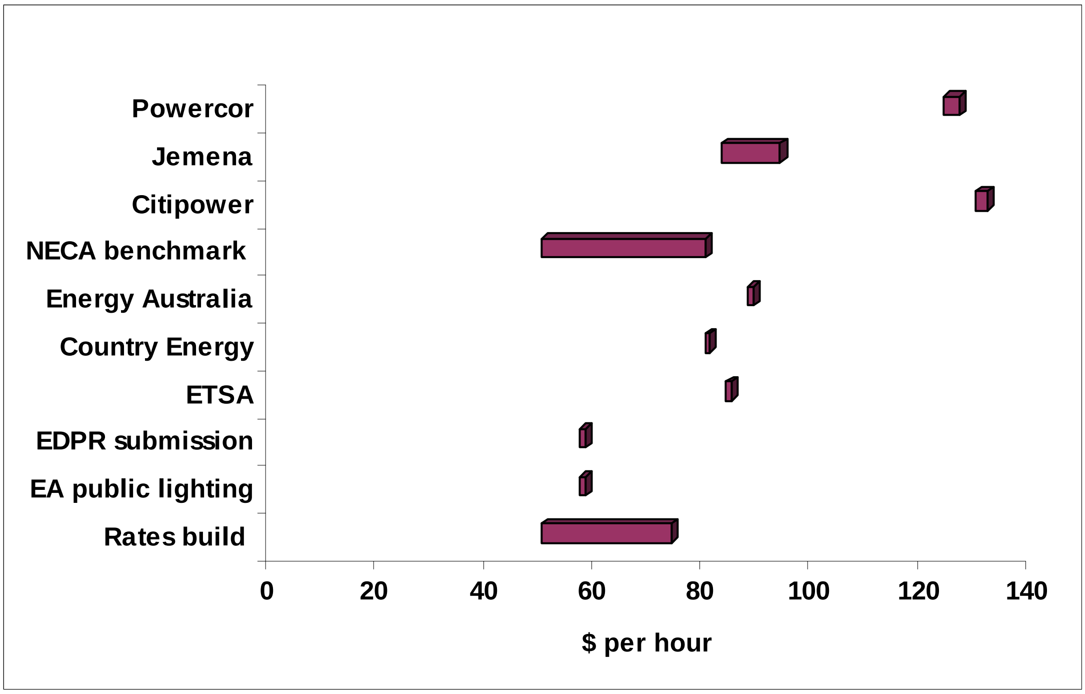
35 The AER notes that its draft decision is for temporary cover of low voltage mains to become a quoted service, however Impaq's review commenced prior to this classification decision. Accordingly, Impaq's consideration of temporary cover of low voltage mains has informed the AER's draft determination on labour rates for quoted services.

36 Impaq Consulting, *Australian Energy Regulator—Victorian Electricity Distribution Determination 2011—Review of Distributors Proposed Rates in ACS charges,* 25 May 2010, pp. 14–16.

- ETSA Utilities—Standard fees publication
- Country Energy—Price schedule for miscellaneous services
- Energy Australia—Price schedule for miscellaneous services
- AER draft decision—Energy Australia draft distribution determination 2009–10 to 2014–15 Alternative Control (public lighting) services, 23 February 2010
- National Electrical and Communications Association (NECA)—2009 annual charge out rate survey.[37]

The following graphs, based on the Victorian DNSPs' equivalent charge out rates, set out Impaq's analysis of CitiPower's, Powercor's and Jemena's equivalent charge out rates compared to other DNSPs and benchmarks.

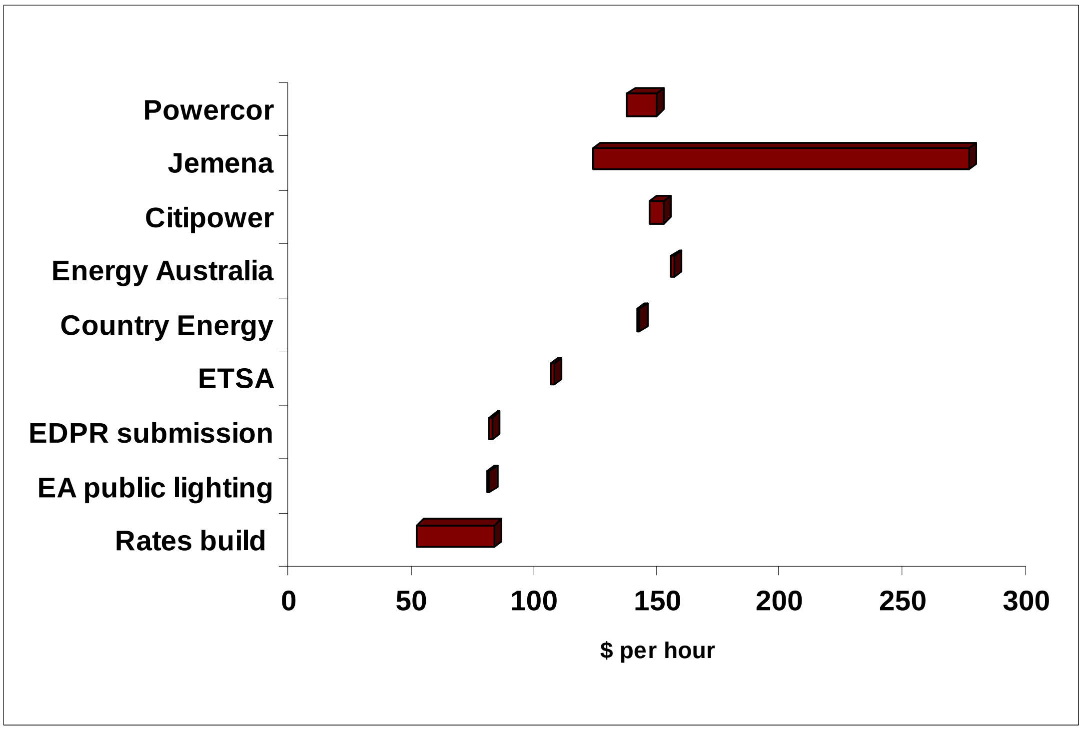
Figure 20.1 Impaq analysis—Business hours line worker charge out rate comparison ($, 2010)



Source: Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, p. 44.
Note: Rates include proposed quoted services hourly rates.

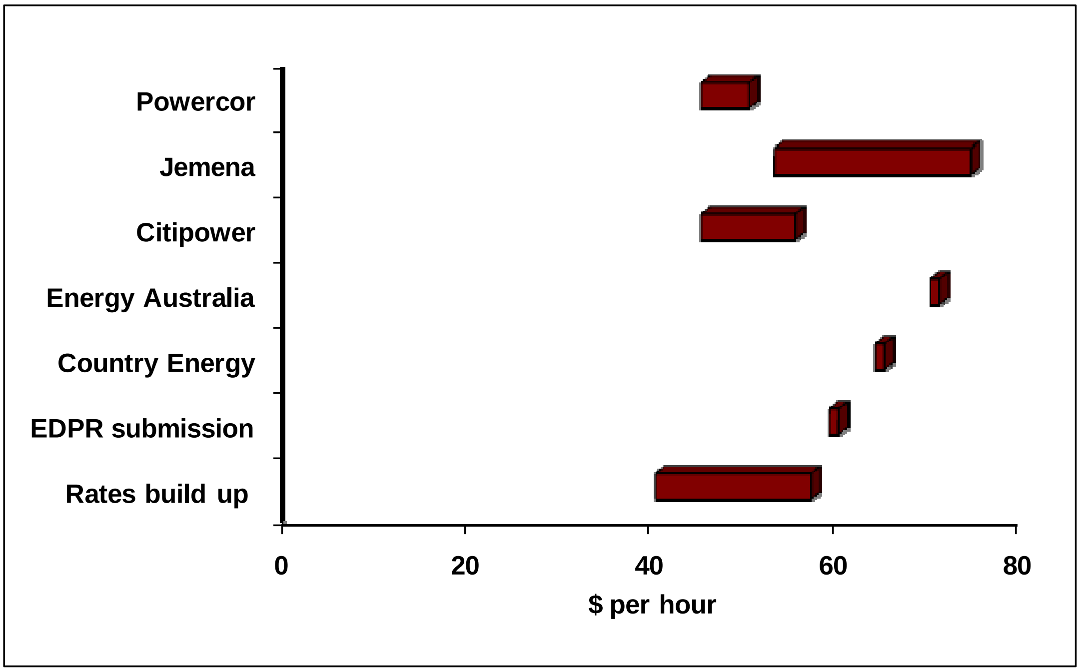
[37] ibid., pp. 31–41.

Figure 20.2 Impaq analysis—After hours line worker charge out rate comparison ($, 2010)



Source: Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, p. 45.
Note: Rates include proposed quoted services hourly rates.

Figure 20.3 Impaq analysis—Back office charge out rates comparison ($, 2010)



Source: Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, p. 46.
Note: Rates include proposed quoted services hourly rates.

The equivalent charge out rates set out in the above graphs incorporate labour on-costs, overheads and a profit margin that Impaq considered to be reasonable.

In comparing costs and prices charged for similar services provided in other jurisdictions, Impaq developed a range of charge out rates for each category of labour which it considered to be reasonable (referred to hereafter as the recommended reasonable range). Table 20.3 summarises Impaq's recommended reasonable range for labour charge out rates for fee based and quoted alternative control services, as well as the equivalent charge out rates proposed by CitiPower, Jemena and Powercor.

Table 20.3 Impaq recommendations on charge out rates and DNSP proposals for fee based services ($, 2010)

Form of labour	Impaq recommended hourly charge out rate range	CitiPower proposed equivalent charge out rate (fee based)	Powercor proposed equivalent charge out rate (fee based)	Jemena proposed equivalent charge out rate (fee based)
Line workers—business hours	74–84	132	124	91
Line workers—after hours	84–105	145	136	272–274
Back office workers	40–60	45–55	45–50	53–74

Note: Charge out rates include all overheads and profit margins.
Source: Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, pp. 14–16, 47–48.

The line worker classification is considered to span both Technical Grades 3 and 4 in the National Electrical Power Industry Award. The back office worker classification (which may be a customer service officer or an administration officer) is considered to span both Administrative Grades 1 and 2 in the National Electrical Power Industry Award.[38]

Time taken to perform services

Impaq considered the time inputs to CitiPower's, Powercor's and Jemena's alternative control services price models for each of the top seven services. Based on Impaq's knowledge of the electricity distribution industry and experience with alternative control services, Impaq considered that in general, the inputs for times taken to perform the alternative control services were significantly overstated by CitiPower, Powercor and Jemena.

Similar to its approach for labour charge out rates, Impaq developed a recommended reasonable range of times for each labour component for each of the top seven services. Impaq recommended that the AER replace many of the time inputs to CitiPower's, Powercor's and Jemena's alternative control service pricing models, to determine an efficient cost for providing the services. Impaq's analysis and

[38] ibid., pp. 31–32.

recommendations of the times taken are provided in its report, and are discussed below.[39]

Materials inputs

Impaq considered the costs of materials inputs to CitiPower's, Powercor's and Jemena's top seven services. Material inputs include:

- temporary cover of low voltage mains—tiger tails, tape and cable ties are used by CitiPower and Powercor to cover their low voltage mains on request. Impaq's investigations revealed the proposed materials costs were reasonable.

- temporary supply—Jemena proposed materials costs in providing temporary supply connections, including service fuses and connectors. Impaq considered that Jemena's proposed materials costs appeared reasonable.

- new connections—CitiPower, Powercor, Jemena and SP AusNet proposed materials costs for new connection services. Impaq considered that the proposed materials costs appeared reasonable, however noted that CitiPower and Powercor may have overlooked some materials in their proposed costs for new connections–current transformer connected—underground supply.[40]

20.6.2 Quoted services

For quoted services, Impaq provided advice on the Victorian DNSPs' proposed hourly labour rates. None of the Victorian DNSPs provided details on materials costs associated with quoted services, however CitiPower, Powercor and Jemena submitted information on the materials costs for temporary cover of low voltage mains, which they proposed as a fee based service. Impaq considered that the Victorian DNSPs' proposed materials costs for temporary cover of low voltage mains are reasonable.[41]

Impaq's analysis of labour rates for quoted services was restricted to the four DNSPs that submitted quoted services prices for labour (CitiPower, Powercor, Jemena and SP AusNet). United Energy did not submit proposed labour rates for quoted services.

CitiPower, Powercor and Jemena each proposed only one appropriate labour classification for quoted services, being a distribution line worker. Impaq's analysis of line worker rates for quoted services is consistent with its analysis for fee based services, set out above. Impaq concluded that the quoted services rates proposed for line workers were at the high end of the comparative range.

SP AusNet also proposed a distribution line worker classification rate, as well as a number of other classification rates for drafting officers, technical officers and engineers. Impaq concluded that SP AusNet's proposed rates for these additional officers were within a comparative range of the rates charged by other DNSPs in the National Electricity Market (NEM), and accordingly were reasonable.[42]

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39 ibid., pp. 49–52.
40 ibid., pp. 53–54.
41 ibid.
42 ibid., pp. 28–30.

20.7 Issues and AER considerations

20.7.1 Fee based services

The following discussion relates to prices for fee based services which will be provided in the 2011–15 regulatory control period, as determined by the service classifications set out in chapter 2 of this draft decision and in table 20.4.

Table 20.4 AER conclusion on service classification of fee based alternative control services for 2011–2015 regulatory control period

Fee based alternative control services
• Supply abolishment • Fault response - not DNSP fault • Energisation of new connections • De-energisation of existing premises • Re-energisation of existing premises • Temporary disconnect / reconnect services • Wasted attendance - not DNSP fault • Service truck visits • Fault level compliance service • Reserve feeder • PV installation • Routine connections, for customers < 100amps • Temporary supply services • Meter investigation • Special meter reading • Re-test types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh

Source: Chapter 2 of this draft decision

In reviewing the proposed prices for fee based alternative control services, the AER considered the following:

- the differing cost build up and top down adjustment methodologies adopted by each Victorian DNSP
- the recommendations made by Impaq on the labour, time and materials inputs into the top seven fee based alternative control services

- profit margins incorporated into alternative control services prices, consistent with the AER's general approach to outsourced transactions outlined in chapter 6 of this draft decision

- labour and materials escalators applied in the Victorian DNSPs' proposed price paths

- the EUCV's submission on the Victorian DNSPs' wages as compared to wages growth in the sector.

The AER also had regard to the factors set out in clause 6.2.5(d) of the NER:

- the potential for development of competition in the relevant market and how the control mechanism might influence that potential—as noted in the Framework and approach paper, the AER considers that there is very little prospect for the development of competition in the provision of the classified fee based and quoted alternative control services. The AER considers that the application of a price cap control mechanism will not have any material impact on competition for the supply of alternative control services or impede the potential to develop competition for the supply of these services.[43]

- the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users—by determining a capped price for 2011 for fee based services, and a capped labour charge out rate for quoted services for 2011, and determining a price path for the remaining years of the regulatory control period, the AER considers it is enabling the lowest possible administrative burden on all parties. The annual price review process will involve the Victorian DNSPs submitting proposed prices for the following regulatory year, which must accord with the form of control set out in the AER's determination in order to be approved. By determining the form of control for the services as part of the determination, customers will be able to calculate the likely prices for the services in years 2012–15, by estimating CPI.

- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination—the AER has had regard to the ESCV's 2006-10 EDPR and Guideline 14 in determining how compliance with the control mechanism is to be monitored and notes that these arrangements provide for a price cap control mechanism for excluded services and for periodic review by the ESCV of the Victorian DNSPs' scheduled prices. The arrangements to be put in place by the AER for monitoring compliance with the control mechanism for alternative control services, which are equivalent to excluded services, are similar to the previous regulatory arrangements.

- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)—in determining prices for fee based services, and hourly labour rates for quoted services, the AER and Impaq have had regard to the prices charged for similar services in other

43 AER, *Framework and approach paper*, p. 77.

jurisdictions. By benchmarking the Victorian DNSPs' prices against a reasonable range of labour charge out rates and times (based on prices around the NEM), the AER has taken the view that the services provided are similar and that prices faced by customers should reflect this. In setting the control mechanisms, the AER has had regard to its approach to determining control mechanisms for quoted and fee based services in other jurisdictions, including Queensland, where a price cap for the first year of the forthcoming regulatory control period and CPI-X control for the subsequent years are applied.

- any other relevant factor—the AER considered the Victorian DNSPs' methodologies for calculating proposed prices, detailed in the following sections. The AER also considered the use of cost escalators, and considers it appropriate that the same escalators which are applied to standard control services within this draft decision should also be applied to alternative control services.

The Victorian DNSPs' current prices for fee based alternative control services are set out in appendix I. The AER notes that all Victorian DNSPs state in their proposals that the prices for their fee based alternative control services have not changed since 1993 (CitiPower and Powercor), 1999 (United Energy and SP AusNet) and the late 1990's (Jemena).[44] As noted previously, the AER understands that prices for most alternative control services have not been adjusted by the ESCV in previous regulatory determinations except in relation to the introduction of the Commonwealth Goods and Services Tax in 2000. It is also noted that the Victorian DNSPs did not provide any information on the original basis and methodology used to set alternative control services prices.

Noting the time that has elapsed since most of the alternative control service prices were last adjusted, and the lack of information on the calculation of the current prices, the AER considers that the current prices are not an appropriate basis for determining the efficient prices for alternative control services for the 2011–15 regulatory control period. This contrasts with the AER's views relating to the costs of providing direct control services (for example, chapters 7 and 8 deal with the DNSP's capex and opex proposals for direct control services). Accordingly, the AER has placed weight on the outcomes of actual cost build ups for each service rather than on the current prices. However, as the Framework and approach paper enabled the Victorian DNSPs discretion to apply a top down adjustment to current prices, the AER has considered current price adjustments where proposed.

Consultant review

As described in section 20.6, Impaq provided advice on a reasonable range of labour charge out rates and times for alternative control services, based on its own industry experience, analysis of services provided by other DNSPs in the NEM, and results of a 2009 survey of charge out rates conducted by NECA. The resulting labour charge out rates are presented in table 20.3, and recommended times are detailed in the following sections for CitiPower, Powercor and Jemena.

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[44] The current control mechanism in Victoria for fee based services, public lighting services, recoverable works and other quoted services is a price cap. Indexation is not automatically applied to capped prices. CitiPower, *Regulatory proposal*, p. 370; Powercor, *Regulatory proposal*, p. 377; United Energy, *Regulatory proposal, Appendix C-2*, p. 34; Jemena, *Regulatory proposal*, p. 216.

In analysing the build up of Impaq's recommended reasonable range of labour charge out rates, which includes direct and indirect overheads and a profit margin, the AER considered the profit margin within Impaq's recommended high case charge out rates, which is 8 per cent. The AER notes Impaq's discussion on profit for alternative control services:

> Alternative Control Services are not capital intensive and hence the application of the standard building blocks of Return of Capital and Return on Capital do not yield meaningful profit margins. However in similar service industries profit margins of from 3% to 8% are common. Given the low risk nature of the revenue earned by the DNSPs for ACS services it is arguable that margins should be at the lower end of the range.[45]

The AER agrees that profit margins for alternative control services should be at the low end of the range recommended by Impaq, being 3 per cent. Acknowledging the discussions below on related party margins and DNSP profits (within the sections discussing each DNSP below), the AER considers that the maximum allowable profit margin which should be applied to alternative control services is 3 per cent.

Accordingly, the AER has amended the Impaq high case labour charge out rates by removing 5 per cent, to account for the AER's view that the maximum allowable profit margin for alternative control services is 3 per cent. Table 20.5 sets out the resulting reasonable range of charge out rates for alternative control services, as applied by the AER in the following sections.

Table 20.5 AER conclusion on Impaq recommended reasonable range and AER adjusted reasonable range, for labour charge out rates ($, 2010)

	Impaq recommended charge out rate range	AER adjusted charge out rate range
Line workers—business hours	74–84	74–79.80
Line workers—after hours	84–105	84–99.75
Back office rates	40–60	40–57

Source: Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, pp. 47–48.

The AER applied the adjusted ranges of labour charge out rates and Impaq's recommended range of time inputs in a cost build up to determine a reasonable range of prices for each service. The AER considers that, with a few exceptions, the highest point in the reasonable range of labour and times reflects the maximum price that DNSPs should recover from the provision of these services (which includes all overheads and a profit margin). While the AER is of the view that it may be appropriate for DNSPs to charge the mid-point or lowest point in the range, it considers that it is conservatively allowing for some potential differences between the services provided by each DNSP, and costs that each DNSP faces, by applying the highest point in the range to proposed service prices that fall above the range (and accepting proposed prices that fall within or below the range).

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45 Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, p. 36.

However, in applying its analysis, the AER has also considered the Victorian DNSPs' overall package of proposed alternative control services prices, and notes that certain DNSPs' prices are significantly lower than others for all or most services. This issue is discussed in more detail in section 20.8.1. The AER has considered each DNSP's proposed price for each service on a case by case basis, placing weight on reasonable ranges of labour and time inputs, the methodologies used to calculate proposed prices, and information submitted by the Victorian DNSPs about the services during the review process.

The following sections outline the AER's considerations of each DNSP's proposed fee based alternative control service prices.

CitiPower and Powercor

In calculating prices for fee based alternative control services, CitiPower and Powercor undertook an identical process to build up the costs of providing each service. CitiPower and Powercor conducted the cost build up to determine prices for services in 2011, and proposed prices for 2012–15 were determined by increasing the 2011 price by labour and materials escalators.[46]

In their regulatory proposals, CitiPower and Powercor provided information on cost build ups for the following selected fee based services: disconnection, reconnection, special reading, various meter testing, meter investigation and PV installation.[47] For the remainder of CitiPower's and Powercor's fee based alternative control services, a top down approach was applied whereby 2010 prices were escalated by CPI and a labour escalator.

On 3 March 2010, CitiPower and Powercor resubmitted proposed prices for all fee based and quoted alternative control services, correcting for errors identified during the AER's and Impaq's review process which were raised with CitiPower and Powercor. In response to the issues raised by the AER and Impaq, CitiPower and Powercor also resubmitted their bottom up cost models, providing cost build ups for all fee based alternative control services.[48] This submission also included a build up of costs for routine new connections, which CitiPower and Powercor had proposed as a standard control service.

CitiPower's and Powercor's resubmitted prices reflected a reduction to the line worker labour rate of 14 per cent and 19 per cent respectively and a reduction to the back office labour rate of 38 per cent and 40 per cent respectively. This change resulted in price reductions to all the services that had been the subject of CitiPower's and Powercor's bottom up cost builds. However, the build up of costs resulted in price increases for those services that were originally calculated on a top down basis by CitiPower and Powercor in their regulatory proposals.

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46 The AER notes that the Victorian DNSPs' proposed labour and materials escalators are identical to those applied in the Victorian DNSPs' opex proposals for standard control services. The AER's consideration of the proposed labour and materials escalators is provided in appendix K. The AER has been consistent between its decision on the escalators applied to opex and for alternative control services.

47 CitiPower, *Regulatory proposal*, p. 376; Powercor, *Regulatory proposal*, p. 383.

48 CitiPower and Powercor, *email to AER staff*, 3 March 2010.

CitiPower's and Powercor's methodology for establishing 2011 prices

CitiPower's and Powercor's build up of costs for alternative control services includes labour and materials costs. The labour costs are determined by the labour rate and the time taken to perform the various tasks associated with performing the service. These tasks include: service initiation (back office bookings, etc); field crew travel; field crew site work; and post service activities (billing and data entry).

The labour rate inputs into CitiPower's and Powercor's service prices were generated using external contractor costs and base labour rates, from service providers CHED Services and Powercor Network Services (PNS). Included within the labour rates are a pro rata of:

- overheads attributable to PNS
- pro rated fleet and property charge
- overheads attributable to CitiPower and Powercor.

CitiPower's and Powercor's cost build up models sum the total internal and external costs of providing each service, before adding a profit margin to derive the final price. CitiPower and Powercor indicated to the AER that the profit margin does not include any overhead costs, rather it is a profit margin reflecting that without a return, the DNSPs would not have an incentive to provide alternative control services.[49]

The AER considers the general methodology adopted by CitiPower and Powercor to build up 2011 alternative control services costs is transparent and reasonable. The following sections assess the reasonableness of inputs applied within this methodology.

Labour, time and materials inputs

Impaq's analysis of labour rate inputs found that, compared to DNSPs in other jurisdictions and the 2009 NECA survey of industry charge out rates, CitiPower's and Powercor's business hours line worker rates were high. Impaq recommended that a reasonable labour charge out rate range for line workers (business hours) was between \$74 and \$84 per hour (\$,2010). CitiPower's proposed equivalent charge out rate is \$132 per hour, while Powercor's proposed equivalent charge out rate is \$124 per hour (\$, 2010).[50]

Impaq considered that the line workers (after hours) rates proposed by CitiPower and Powercor were also overstated, with their equivalent charge out rates being \$145 and \$136 per hour (\$, 2010) respectively. This compares to Impaq's recommendation that a reasonable charge out rate range for line workers (after hours) is between \$84 and \$105 per hour (\$, 2010).[51]

[49] AER, *file note of meeting with CitiPower and Powercor*, 18 February 2010.

[50] The AER notes that the equivalent hourly charge out rates incorporate all on-costs, overheads and margins as proposed by the Victorian DNSPs.

[51] Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, pp. 14–16, 47–48.

Impaq considered that CitiPower's and Powercor's proposed hourly rates for back office workers were reasonable.[52]

The AER considers that CitiPower's and Powercor's proposed hourly labour rates for line workers, in both business and after hours times, are significantly higher than industry standards. In determining the approved fee based alternative control services prices for this draft determination, the AER considered the reasonable range for alternative control services prices, based on the ranges of equivalent charge out rates recommended by Impaq. The AER considers that the highest point of Impaq's reasonable range of labour charge out rates, adjusted to allow a 3 per cent profit margin (as discussed above) within table 20.5 should be applied to CitiPower's and Powercor's hourly rates for business and after hours line workers.

The AER accepts the hourly labour rates for CitiPower's and Powercor's back office staff as reasonable.

Contract rates

CitiPower's and Powercor's reconnection, disconnection and special meter read services include a particular service provider's contract rates in the build up of costs. This service provider is subcontracted by PNS, and is not considered a related party to CitiPower or Powercor. The service provider's rates apply to site work done by their field crew and make up a considerable proportion of the end price. The service provider's rates were not reviewed by Impaq. CitiPower and Powercor have advised the AER that these service provider's rates were provided to the businesses through recent contract negotiations.[53] The AER notes that the service provider's rates increase significantly over the forthcoming regulatory control period such that by 2015 they are double the 2011 rate.

CitiPower and Powercor stated that the forecast increases in the service provider's contract rate inputs over the forthcoming regulatory control period are a result of the AMI rollout. As the AMI rollout will result in fewer *manual* reconnection and disconnection services and special meter reads (due to *remote* services becoming available), certain overhead costs will increase proportional to the direct costs of providing the service.[54] That is, as *remote* reconnection, disconnection and special meter reads become available (and fees for remote services are regulated as 'excluded services', as discussed in section 20.4.1), these *manual* services will cease to be necessary, and requests for the services will decline. However, as the DNSPs will still need to retain staff and vehicles to carry out the few *manual* services requested (until the AMI rollout is complete), declining economies of scale will result in a higher average cost to carry out these *manual* services. The AER notes that it expects DNSP prices for future AMI-related *remote* services will be a fraction of the price of an equivalent *manual* service, due to the minimal labour required to perform a remote service through an AMI meter.

Based on information provided by CitiPower and Powercor, and a comparison of the affected service prices across the Victorian DNSPs, the AER considers the service

[52] ibid.
[53] CitiPower and Powercor, *email to AER staff*, 22 March 2010.
[54] ibid.

provider's rates for 2011 are reasonable. However, the AER considers that despite CitiPower's and Powercor's argument that the AMI rollout will result in increased costs for manual services, the significant escalation of this service provider's rates over 2012–15 has not been sufficiently justified.

Times

Table 20.6 summarises Impaq's analysis of CitiPower's and Powercor's time inputs for the top seven services. It is evident that there is a significant overstating of the times proposed to provide the relevant services.

Table 20.6 Impaq analysis—CitiPower and Powercor's proposed times for alternative control services

Alternative control service	Findings on CitiPower and Powercor's proposed times taken in providing services
Field officer visits—Special reads (accumulation meter)	Back office times overstated by 260%
Re-energisation—Existing premises (manual)	Back office labour times reasonable
De-energisation (manual)	Back office labour times reasonable
Service Vehicle visits	Back office rimes overstated by 60%, field officer times overstated by 30%, Powercor's scheduling team times overstated by 200%
Wasted service vehicle visits	Back office labour times reasonable, field officer times overstated by 100%
Meter equipment test—single phase	Back office times overstated by 60%, field officer times overstated by 80%
Meter equipment test—single phase, each additional meter	Back office times overstated by 460%, field officer times overstated by 400%
Meter equipment test—multi phase	Back office times overstated by 60%, field officer times overstated by 100%
Meter equipment test—multi phase, each additional meter	Back office times overstated by 460%, field officer times overstated by 360%
Meter equipment test—CT multi phase	Back office times overstated by 50%, field officer times overstated by 50%
Temporary cover of mains—service lines and low voltage mains	Back office times overstated by 120%, field officer times overstated by 10%
Temporary supply—coincident abolishment	Times not provided.
New connections—single phase, single element	Back office times overstated by 15%, field officer times reasonable, scheduling team times included in back office times, and vehicle times appear reasonable.
New connections—three phase direct connected	Back office times overstated by 15%, field officer times reasonable, scheduling team times included in back office times, and vehicle times appear reasonable
New connections—three phase current transformer connected	Back office times overstated by 20%, inspection and testing time appears reasonable, field officer times reasonable, scheduling team times included in back office times, and vehicle times appear reasonable

Source: AER analysis of high end of reasonable time range within advice provided in Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, pp. 49–52.

Note: All services are manual, this draft determination does not approve prices for remote services becoming available as a result of the AMI rollout.

Table 20.6 outlines the AER's interpretation of Impaq's findings that, in building up the costs for the top seven services, CitiPower and Powercor have significantly overstated the times needed for many labour components. Impaq provided a reasonable range of times in which the various components of each service could be expected to be performed. The AER considers that where Impaq has found CitiPower's or Powercor's times to be outside a reasonable range, it is appropriate to apply the highest point of Impaq's recommended times for the services. The AER notes that the resulting prices are significantly lower than CitiPower's and Powercor's proposed alternative control services prices.

CitiPower and Powercor proposed some materials costs for temporary cover of low voltage mains and for new connection services. As this draft determination classifies this service as a quoted service, these costs are considered in section 20.7.2.

To derive draft determination prices for services for which Impaq did not provide recommended times, the AER was able to determine times based on the description of the task and the times recommended by Impaq for similar tasks. The AER also applied Impaq's recommended labour rates, adjusted to include a 3 per cent profit margin, as set out in table 20.5 above. The following section details the AER's analysis of CitiPower's and Powercor's proposed profit margins.

Profit margins

Both CitiPower and Powercor outsource the provision of their alternative control services to two related parties, CHED Services and PNS. CitiPower, Powercor, CHED Services and PNS are all 100 per cent owned by CHEDHA Holdings Pty Ltd. CHED Services provides management, corporate overheads and call centre services associated with alternative control services, while PNS provides the field services associated with alternative control services.

The contracts between CitiPower and CHED Services, and Powercor and CHED Services allow CHED Services to recover a profit margin applied to all services. Similarly, the contracts between CitiPower and PNS, and Powercor and PNS allow PNS to recover a profit margin applied to all services. In addition, PNS subcontracts out to a number of alternative control service providers in both CitiPower's and Powercor's network areas.

As noted above, CitiPower and Powercor apply an additional margin to the CHED Services and PNS prices, in order to provide CitiPower and Powercor with profit for the provision of alternative control services. CitiPower and Powercor advised that this margin is in addition to all direct and indirect overheads incurred in the provision of alternative control services.[55]

The AER notes that Impaq's analysis of the hourly labour rates included a limited assessment of profits within the rates, and profit margins are included within Impaq's recommended hourly labour charge out rate range.

Application of approach to outsourced contracts established in chapter 6 of this draft decision

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[55] AER, *File note of meeting with Impaq Consulting, CitiPower and Powercor*, 17 February 2010.

The AER has considered CitiPower's and Powercor's outsourced profit margins included within their proposed prices for alternative control services consistent with the AER's general approach to considering outsourcing arrangements, outlined in chapter 6 of this draft decision.

- Stage 1—presumption threshold
  - The AER's general approach to assessing outsourced transactions involves assessing the contracts under a two stage process. The first stage is a presumption threshold, which considers whether the DNSP had an incentive to enter into a non-arms length contract. Where the contract to provide services is between a DNSP and its related party, as is the case with CitiPower's and Powercor's contracts with CHED Services and PNS, the AER considers the DNSPs do have an incentive to enter into a non-arms length contract.
  - The AER's approach also considers whether there was an open tender process conducted in a competitive market to obtain the contract. In the case of the alternative control services contracts held by CitiPower and Powercor, the AER notes there were no competitive tender processes undertaken prior to the establishment of the contracts.
- Stage 2—assessment where the presumption threshold is not passed
  - Where the margins in consideration do not pass the first stage in the AER's general approach to assessing outsourced contracts (as in this case for CitiPower and Powercor), the next stage of the AER's approach involves consideration of whether the contract reflects the costs that would be incurred by an efficient operator. This involves examining the basis of the related parties' underlying costs, and potentially performing a counterfactual cost build up.
  - For alternative control services, as outlined above, the AER's review has involved industry benchmarking of costs and final alternative control service prices, based on advice provided by Impaq. The cost build up models and information submitted by CitiPower and Powercor have enabled the AER to distinguish the proportions of profit margins and other returns available to CitiPower and Powercor and their outsourced contractors for the provision of alternative control services.
  - Following the approach to assessing outsourced transactions in chapter 6 of this draft decision, the AER's review of the alternative control services contract margins has ultimately focussed on the issue of whether any margin is necessary to compensate the contractors for economies of scale and scope, or know how, which would otherwise be unavailable to the DNSPs should they elect to provide the services in-house or via a different contractor. The AER's approach is also to consider whether a profit margin is necessary to compensate for any return of/on assets or common costs which would otherwise not be provided for.
  - Unlike standard control services, alternative control services consist almost entirely of labour. With the exception of SP AusNet's and Jemena's new

connection services, the Victorian DNSPs do not allocate any capital costs (return on/of) to alternative control services within their cost allocation methodologies. All alternative control services capital costs are considered 'shared costs', and are recovered via standard control service charges. The Victorian DNSPs cost allocation methodologies are discussed further in chapter 6.[56] The materials cost of lines for routine connections is fully funded up front by customers and consequently no return on capital is required for these 'gifted' assets.

  - Accordingly, there are very few capital assets associated with the provision of alternative control services for which DNSPs are entitled to roll into their asset bases and recover a weighted average cost of capital (WACC). Opex assets (labour or human capital, also known as intangible assets) are expensed and do not earn a return under the building block approach. Some DNSPs have expressed a view that without a profit margin or a return on these intangible assets via the WACC, there would be no incentive for their contractors, or indeed the DNSPs themselves, to provide the alternative control services.[57]

  - The AER's approach to related party transactions with regard to returns on intangible assets relies on the ability of the DNSP to retain any efficiencies made in the provision of services (that is, declining opex) for a period of time, via the efficiency benefit sharing scheme (EBSS). The AER's general approach is that returns on intangible assets are available through the ability of the DNSP (and in effect, its related parties) to retain any efficiency gains they make for five years via the EBSS, after which the efficiencies are shared with customers. Alternative control services are not subject to the EBSS, rather the AER has discretion to enforce efficiency gains via a CPI–X control mechanism to be reset at each distribution determination. As such, in the absence of a profit margin, efficiencies (or returns on intangible assets), are, in effect, not able to be retained by the DNSPs for any time beyond the five year regulatory control period. In the case of alternative control services, the AER considers it may be necessary to enable CitiPower and Powercor and their contractors to earn a profit over the forthcoming regulatory control period to enable them to retain efficiencies generated in the current regulatory control period. However, the AER considers that these efficiencies should be passed back to customers in the 2016–20 regulatory control period.

- AER conclusion—outsourced profit margins

  - In conclusion, in applying the AER's general approach to outsourced transactions and profit margins outlined in chapter 6, the AER finds that it may be efficient for alternative control services charges (being provided either in-house or via an outsourced contract) to incorporate profit margins. This is because in the absence of an EBSS for alternative control services, there isn't a mechanism to reward efficiencies generated during the current regulatory control period beyond 2010. The AER considers that in order for the AER to

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[56] Only the direct costs of operating vehicles are included in the alternative control services prices, the capital costs of the vehicles are recovered via standard control charges.

[57] AER, *file note of meeting with CitiPower and Powercor*, 18 February 2010.

allow CitiPower and Powercor to recover a profit margin on alternative control services prices in the 2016–20 regulatory control period, the DNSPs would need to demonstrate incremental efficiencies gained during the forthcoming regulatory control period.

- The AER notes that its draft determination approved prices incorporate a labour charge out rate inclusive of a 3 per cent profit margin that the AER considers is reasonable for the provision of such services.

DNSP profit margins

In addition to CHED Services' and PNS' related party profit margins, both CitiPower and Powercor charge a profit margin, despite not providing any of the services themselves, nor adding any identifiable value to the services provided under the contracts.

The AER has previously considered the application of a profit margin to a service price where the party applying the margin is not actually providing nor adding any value to the service, rather simply passing through the costs plus margins. In the AER's draft decision for Jemena Gas Networks (JGN) for 2010–15, the AER rejected JGN's profit margins to be paid to Jemena Asset Management (JAM), noting that where JAM was outsourcing the services subject to the profit margin, and not adding any value, the cost structure is inefficient.[58]

The AER notes that the profit margins applied by CitiPower and Powercor to final alternative control services prices are in addition to the related party margins paid by the DNSPs to CHED Services and PNS. As stated above, the AER's draft determination approved prices incorporate a labour rate recommended by Impaq, adjusted to include a profit margin that the AER considers reasonable for the provision of such services.[59] The AER considers that it is inefficient for CitiPower and Powercor to earn an additional margin on alternative control services when the DNSPs do not actually provide, nor add any identifiable value to, the services. Accordingly, the AER has not included the DNSPs' profit margins in the build up of prices for CitiPower and Powercor for this draft decision.

AER conclusion— profit margins

For the reasons set out above, the AER's draft decision is to allow a profit margin to be applied to CitiPower's, and Powercor's prices for alternative control services. As outlined above, this margin equates to 3 per cent above direct wages costs.

The AER's draft decision is to remove the additional margin applied by CitiPower and Powercor to their alternative control service charges for 2011.

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[58] AER, *Draft decision—Jemena Gas Networks (NSW)—1 July 2010 – 30 June 2015*, February 2010, p. 186.

[59] As noted above, the AER has applied the high case labour charge out rates recommended by Impaq in approving prices for alternative control services, but has removed 5 per cent from the high case charge out rates to account for its view that a reasonable profit margin for alternative control services is 3 per cent.

Labour and materials escalators

CitiPower's and Powercor's proposed alternative control services prices incorporate general outsourced labour and materials escalators provided by their consultants, respectively BIS Shrapnel and Sinclair Knight Merz (SKM).

The AER's general consideration of labour and materials escalators for the purposes of its assessment of capex and opex for standard control services is outlined in appendix K. The AER considers it is appropriate to employ a consistent approach between assessing the proposed escalators applied to standard control services and escalators applied to alternative control services.

In determining prices for alternative control services as part of this draft decision, the AER has applied the labour and materials escalators it has approved for standard control services, outlined in appendix K. Table 20.7 outlines the labour and materials escalators applied by the AER in calculating CitiPower's and Powercor's alternative control services prices for this draft decision.

Table 20.7 AER conclusion on approved outsourced labour and materials escalators for CitiPower and Powercor (per cent)

	2011	2012	2013	2014	2015
CitiPower—Insourced Labour	0.99	1.00	0.88	1.94	1.46
CitiPower—Outsourced labour	0.87	1.48	1.89	1.87	0.69
CitiPower—Materials	2.76	0.43	–0.81	–1.59	–1.91
Powercor—Insourced Labour	0.96	0.99	0.87	1.93	1.46
Powercor—Outsourced labour	0.87	1.48	1.89	1.87	0.69
Powercor—Materials	2.70	0.45	–0.88	–1.59	–1.87

Source: Appendix K; CitiPower and Powercor, *email to AER staff*, 13 May 2010.

Price path—fee based services

CitiPower and Powercor did not explicitly propose a price path based on a CPI–X control mechanism as set out in the Framework and approach paper. Instead CitiPower and Powercor proposed individual prices for each year of the forthcoming regulatory control period, which varied between each service and year.

The AER found that CitiPower's and Powercor's proposed prices for reconnection and disconnection services and special meter reads increased significantly, by between 77 per cent and 94 per cent, over the forthcoming regulatory control period. As discussed above, CitiPower and Powercor advised the AER that this is the result of a doubling of their service provider's contract rate for field site crew for these services.[60]

[60] CitiPower and Powercor, *email to AER staff*, 22 March 2010.

While the proposed increase in prices can in part be explained by an increase in the incremental cost of providing these services as a result of the AMI roll out (that is, declining economies of scale as fewer manual services are requested, being replaced by remote services), the AER considers that the significant assumed cost increase over the forthcoming regulatory control period has not been adequately justified. The AER requests that CitiPower and Powercor provide a more detailed breakdown of their service provider's contract rates for years 2012–15, including hourly labour rates, and a detailed breakdown of the activities being performed in the provision of each service.

In the absence of information supporting the significant price increases during the forthcoming regulatory control period, the AER has not approved CitiPower's and Powercor's proposed prices for 2012 to 2015 in this draft decision.

The AER also considers CitiPower's and Powercor's proposal for individual prices for each year of the forthcoming regulatory period is inconsistent with a price path based on a CPI–X control mechanism, as required by the Framework and approach paper. CitiPower and Powercor did not propose X factors to be applied to each service within a CPI–X control mechanism.

Accordingly, the AER requires CitiPower and Powercor to submit price paths consistent with the Framework and approach paper for their fee based alternative control services as part of their revised regulatory proposals. The AER considers that CitiPower's and Powercor's price paths should incorporate the labour and materials escalators the AER has approved for standard control services, set out in appendix K.

Conclusion—CitiPower's and Powercor's fee based alternative control services 2011 prices and price paths

In conclusion, the AER rejects CitiPower's and Powercor's proposed fee based alternative control service prices for 2011.

As discussed above, CitiPower and Powercor submitted prices for routine new connections during the AER's review. The AER considered CitiPower's and Powercor's build up of routine new connection services with regard to Impaq's advice on reasonable rates and times. Based on the advice provided by Impaq, the AER rejects CitiPower's and Powercor's proposed prices for routine new connections.

The AER has made the following adjustments to CitiPower's and Powercor's proposed prices for 2011:

- applied the high point of business and after hours line worker hourly charge out rates recommended by Impaq, after reducing the rate to account for a 3 per cent profit margin

- where the proposed times were found to be above the reasonable range determined by Impaq, applied the high point of the recommended times taken to perform alternative control services

- applied labour and materials escalators as per those applied to standard control services, outlined in appendix K

- removed the additional profit margin applied by CitiPower and Powercor.

The AER has not approved prices for the following services for CitiPower and Powercor:

- Audit design—CitiPower and Powercor proposed this service as standard control. The AER has classified this service as a quoted alternative control service and therefore requires CitiPower and Powercor to propose an hourly labour rate for this service

- Reserve feeder—CitiPower and Powercor proposed this service to be a negotiated service. The AER has classified this service as an alternative control fee based service and therefore requires CitiPower and Powercor to propose a fee for this service

- Re-test of type 5 and 6 meters—CitiPower and Powercor proposed this service to be an unregulated service. The AER has classified this service as an alternative control fee based service and therefore requires CitiPower and Powercor to propose a fee for this service

- Fault level compliance—CitiPower proposed this service as a standard control service, and proposed to charge embedded generators a one off capital contribution of $625 per kWh ($2009).[61] The AER considers fault level compliance to be an alternative control fee based service, as detailed in chapter 2. As CitiPower did not provide any information on the underlying costs of providing this service as part of its regulatory proposal, the AER requests that CitiPower provide further information to support the proposed kWh fee as an alternative control service fee as part of its revised regulatory proposal.

The AER's draft determination on CitiPower's and Powercor's fee based alternative control services prices for 2011 is set out in appendix O.

The AER does not approve the significant escalation of service provider contract rates within CitiPower's and Powercor's alternative control services prices over 2012–15. The AER requires CitiPower and Powercor to submit price paths consistent with the Framework and approach paper for their fee based alternative control services as part of their revised regulatory proposals. The AER considers that CitiPower's and Powercor's price paths should incorporate the labour and materials escalators the AER has approved for standard control services, set out in appendix K.

Jemena

Jemena provided a bottom up cost model to determine the costs of providing its fee based alternative control services. The bottom up cost model applies to all alternative control services except for metering data provider services for unmetered supplies

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[61] CitiPower, *email to AER staff*, 23 February 2010.

with type 7 metering installations and supply enhancement at customer request–reserve feeder, for which prices were calculated using a top down approach.[62]

Jemena's bottom up cost model involves a build up of labour, motor vehicle and other (material) costs. Labour costs for each service are based on a dollar per hour labour rate and the time taken to perform each task involved in undertaking the service. Jemena's methodology for building up services is discussed in further detail below.

Jemena also submitted a cost build up for routine new connections despite proposing this service as a standard control service. Unlike CitiPower and Powercor, Jemena did not submit proposed prices for new connections where Jemena is not responsible for metering. In the current regulatory control period, the Victorian DNSPs have differing charges for new connections depending on whether or not they are the responsible person, due to the potential for customers to have meters supplied by other parties. On 29 January 2009, the AEMC amended the NER to include a derogation for Victoria requiring that the DNSPs are responsible for all small customers' (consuming less than 160MWh per annum, aside from those with a type 1 or 2 meter) metering installations, to enable the rollout of AMI in Victoria.[63] The derogation was made as rule 9.9B of the NER. Clause 9.9B.2 requires that the derogation is to expire on the earlier of 31 December 2013 or the commencement of other associated amendments to the NER.[64] As the forthcoming regulatory control period extends beyond 31 December 2013, the AER considers that the Victorian DNSPs will need to have charges for new connections where the DNSP is not the responsible person for the regulatory years 2014 and 2015. Accordingly, the AER requests that Jemena submit proposed charges for new connections where it is not the responsible person for metering, to apply in 2014 and 2015, as part of its revised regulatory proposal.

On 19 March 2010, following discussions with the AER in which errors were uncovered in Jemena's cost build up model, Jemena resubmitted its proposed fee based alternative control services prices. The resubmitted prices reflected a 29 per cent reduction in its proposed hourly labour rate for line workers. The resubmitted prices also reflected revisions to the times taken to perform certain alternative control services. Jemena's adjustments resulted in price decreases for a number of its fee based alternative control services.[65]

On 1 April 2010, in response to AER queries regarding contract rates for Skilltech, Formway and Transfield, Jemena advised the AER that it had discovered minor errors in its contract rates and provided a further submission resulting in further price decreases for some of its fee based alternative control services.[66]

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62 Jemena, *Regulatory proposal*, p. 215. Meter data provider services for unmetered supplies with type 7 metering installations are dealt with under clause 6 of the AMI Order in Council. This draft determination does not approve charges for unmetered supplies, these are approved under the annual tariff approval process. The AER notes that the Framework and approach paper indicated unmetered supplies would be an alternative control service, however this is incorrect.

63 AEMC, *National Electricity Amendment (Victorian Jurisdictional Derogation (Advanced Metering Infrastructure Roll Out) Rule 2009 No. 2,* commencing 1 July 2009.

64 NER, cl. 9.9B.2(a) and (b).

65 Jemena, *email to AER staff*, 19 March 2010.

66 Jemena, *email to AER staff*, 1 April 2010.

Jemena's methodology for establishing prices

Jemena outsources a large proportion of its business operations, including alternative control services, to service provider Jemena Asset Management (JAM). Further details and consideration of Jemena's outsourcing practices are discussed in chapter 6.

Jemena stated that the costs it incurs in providing fee based alternative control services consist mainly of the charges it pays to JAM for providing the services. These charges are comprised of:

- JAM's direct costs of providing the service—built up for each service through a managerial assessment of the number of people involved in delivering the service, the average time taken to deliver each service, the labour rates applicable for the JAM staff undertaking the work or the labour rates for the relevant external sub-contractor, the type and average quantity of materials consumed for each service using stores material cost rates and motor vehicle and plant charge out rates

- an allocation of JAM's indirect costs of providing the service—Jemena stated that a revenue based allocator has been used to allocate indirect costs.[67] The allocator estimates indirect costs for routine alternative control services to be equal to 7 per cent of direct costs. This allocation is based on the approximate proportion of revenue derived by Jemena from alternative control services, compared to total Jemena revenue

- JAM's margin under the Asset Management Agreement (AMA)—Jemena assumes that a specified margin will be paid to JAM for delivering routine alternative control services on behalf of Jemena.[68] This margin is based on Jemena's contract with JAM, which is discussed further below.

In its regulatory proposal Jemena stated that no shared assets have been allocated to the costs of providing alternative control services and, accordingly the costs of these services are entirely opex. The only assets used in the provision of fee based alternative control services are motor vehicles and plant equipment. Jemena's cost allocation mechanism does not discern between the use of these assets in the provision of standard control services, alternative control services, negotiated and unregulated services. Assets are allocated to services for which the assets are used most, being standard control services. The costs of operating the assets to provide routine alternative control services are reflected in the cost build up for each service, through a fleet charge out rate.[69] The costs of operating Jemena's motor vehicles and plant for alternative control services are based on the motor vehicle and plant rates approved by the AER in its Energy Efficient Public Lighting Charges—Victoria, Final Decision February 2009.[70]

Jemena's bottom up cost model uses 2008 nominal labour, vehicle and material costs to build up the price of each fee based alternative control service. To convert prices to 2010 dollars Jemena breaks down the costs of each service into individual labour and

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67 Jemena, *Regulatory proposal*, p. 218.
68 ibid.
69 ibid.
70 Jemena, *email to AER staff*, 5 February 2010.

material components and applies escalators forecast by BIS Shrapnel for labour, and by SKM for materials.[71]

Jemena includes a corporate indirect overhead cost determined within its cost allocation methodology in its build up of costs. For routine new connection services, Jemena includes a capex overhead.

The AER considers Jemena's overall methodology for building up fee based alternative control services costs is reasonable. The following sections assess the reasonableness of inputs applied within this methodology.

Labour, time and material inputs

Labour charge out rates

Impaq's analysis of labour charge out rates found that, compared to DNSPs in other jurisdictions and the 2009 NECA survey of industry charge out rates, Jemena's proposed labour rates are generally at the high end of a comparative range.

Impaq recommended that a reasonable labour charge out rate range for line workers (business hours) was between $74 and $84 per hour ($, 2010). Jemena's equivalent charge out rate, as calculated by Impaq, for a line worker (business hours) for most fee based services is $91.39, and for Jemena's connection services is $90.54 ($, 2010).[72] Impaq calculated Jemena's equivalent labour charge out rate for a general line worker (after hours) as $274.17 ($, 2010). It calculated Jemena's connection services equivalent charge out rate for a general line worker (after hours) as $271.61 ($, 2010).[73]

Impaq noted that in some cases, the Victorian DNSPs' fee based services after hours rates are charged at a premium above incurred costs, due to their view that customers should be discouraged from requesting services after hours. Impaq noted that this approach reflects a departure from cost reflectivity principles, and recommended a reasonable cost reflective range for after hours charge out rates for general line workers of between $84 and $105 per hour ($, 2010).[74]

In calculating its proposed alternative control services prices, Jemena incorporated a number of back office rates. Impaq calculated Jemena's equivalent labour charge out rates for back office workers for most services as being between $53.02 and $74.36 per hour ($, 2010). For new connections services, Impaq calculated Jemena's equivalent charge out rate for back office workers as $73.66 per hour ($, 2010). Impaq's recommended range of charge out rates for back office workers is $40 to $60 per hour ($, 2010). In summary, Impaq found that some of Jemena's back office rates fall within its reasonable range, however some of the back office rates are well above the reasonable range.[75]

In addition to back office worker time, some of Jemena's proposed alternative control services prices incorporate work by a job scheduling team. Impaq did not provide

71 Jemena, *Regulatory proposal,* p. 219.
72 Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, pp. 14–16 and 47–48.
73 ibid.
74 ibid., pp 47–48.
75 ibid., pp. 14–16 and 48–49.

advice on a reasonable charge out rate for a scheduling team worker, however noted that the work is highly similar to that performed by a back office worker.[76] While the other Victorian DNSPs do not specifically incorporate work by a scheduling team, their alternative control service scheduling time is performed either by a back office or line worker. Jemena's proposed rate for the scheduling team falls between its proposed rates for back office and line workers.

Based on the advice provided by Impaq on a reasonable range of labour charge out rates, the AER considers that Jemena's proposed hourly labour rates for line and back office workers, in both business and after hours times, are significantly higher than industry standards. In determining the approved fee based alternative control services prices for this draft decision, the AER considers that it is reasonable to apply the highest point of Impaq's recommended range of labour rates for each of the services, adjusted to allow a 3 per cent profit margin, as discussed above. For Jemena's scheduling team labour, the AER considers that a rate at the midpoint between the adjusted Impaq recommended back office rate and line worker rate would reflect a reasonable rate due to the nature of the work carried out by the scheduling team (being tasks including those of a back office worker and a line worker). The AER notes that the highest point reflects the maximum labour charge out rate within the reasonable range determined by Impaq (and adjusted for the AER's view of a reasonable profit for these services), and that the resulting labour rates are substantially lower than those proposed by Jemena. Applying the highest point in the range reflects the AER's conservative approach allowing for potential differences between the services carried out by each DNSP.

Accordingly, in determining the draft decision prices, the AER has applied the highest point in the reasonable range recommended by Impaq (after reducing the rate to account for the low end of Impaq's recommended profit margin) for both business and after hours line workers and for back office workers, where Jemena's labour rate falls outside of the reasonable range.

Time taken to perform services

Table 20.8 summarises Impaq's analysis of Jemena's time inputs for the top seven service categories. In most cases, Jemena's proposed times were high relative to those recommended by Impaq.

[76] ibid., p. 42.

Table 20.8 Impaq analysis—Jemena's proposed times for alternative control services

Alternative control service	Findings on Jemena’s proposed times taken in providing services
Field officer visits—Special reads (accumulation meter)	Back office times labour times overstated by 40%
Re-energisation—Existing premises (manual)	Back office labour times reasonable
De-energisation (manual)	Back office labour times over stated by 73%
Service Vehicle visits	Back office rimes overstated by 50%, field officer times appear reasonable. Scheduling team times overstated by 150%
Wasted service vehicle visits	Back office labour times overstated by 150%, field officer times overstated by 67%
Meter equipment test—single phase	Back office times labour times appear reasonable, field officer times N/A
Meter equipment test—multi phase	Back office times labour times appear reasonable, field officer times N/A
Temporary cover of mains—service lines and low voltage mains	Back office times overstated by 120%, field officer times overstated by 10%
Temporary supply—coincident abolishment	Back office times overstated by 67% assume scheduling times included in back office times, vehicle times appear reasonable.
New connections—single phase, single element	Back office times overstated by 67%, field officer times reasonable, scheduling team times included in back office times, and vehicle times appear reasonable.
New connections—three phase direct connected	Back office times overstated by 67%, field officer times reasonable, scheduling team times included in back office times, and vehicle times appear reasonable
New connections—three phase current transformer connected	Back office times overstated by 67%, inspection and testing time appears reasonable, field officer times reasonable, scheduling team times included in back office times, and vehicle times appear reasonable

Source: AER analysis of high end of reasonable time range within advice provided in Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, pp. 49–52.

Table 20.8 outlines the AER's interpretation of Impaq's findings that, in building up the costs for the top seven services, Jemena has overstated the times needed for a number of tasks. Impaq provided a range of times in which the various components of each service could be expected to be performed. The AER considers that it is reasonable to apply the highest point of Impaq's recommended range of times for the services, where the proposed times fall outside the recommended reasonable range.

Applying the highest point in the range reflects the AER's conservative approach allowing for potential differences between the services carried out by each DNSP. The AER notes that the resulting times are significantly shorter than those proposed by Jemena, and when applied in a cost build up, result in significantly lower prices than those proposed by Jemena.

To derive draft decision prices for services for which Impaq did not provide recommended times (outside the top seven services), the AER determined times based on the description of the task and the times recommended by Impaq for similar tasks.

Materials costs

Jemena proposed some materials costs for temporary cover of low voltage mains, temporary supply—coincident abolishment, and for its new connection services. Materials are included at cost.[77] Impaq reviewed the materials costs proposed, and considered the costs were reasonable.[78] The AER agrees that the materials costs for these services as proposed by Jemena are reasonable.

Contract rates

In addition to JAM's labour rates, time taken to perform services and materials costs, Jemena's build up of costs for certain services also includes contract rates, where work is contracted out by JAM and carried out by Skilltech, Formway and Transfield. Neither Skilltech, Formway nor Transfield are considered to be related parties of Jemena.

Skilltech contract rates are applied in the build up of costs for the following services:

- manual energisation of new premises
- manual re-energisation of existing premises
- manual de-energisation of existing premises
- temporary disconnect—reconnect for non payment
- adjust time switch
- manual special reads.[79]

Formway contract rates are applied in the build up of costs for certain meter test services. JAM also has a contract with Transfield to provide services relating to the temporary cover of low voltage wires.[80]

The contract rates for Skilltech, Formway and Transfield apply to site work performed by field crew, and were not reviewed by Impaq. Jemena has advised the AER that the contract rates were provided to the businesses through recent negotiations between

77 Temporary cover of low voltage mains is classified in this draft decision as a quoted service, and is considered in section 20.7.2.

78 Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, pp. 53–54.

79 Jemena, *Regulatory proposal, Appendix 16.1*, 30 November 2009.

80 Jemena, *email to AER staff*, 1 April 2010.

JAM and the contractors, and provided the AER with copies of invoices and service orders for recent services.[81] Based on the information provided by Jemena, the AER is satisfied that the proposed contract rates are the subject of agreements between JAM and its service providers. However, the AER notes that it was not provided with any information demonstrating that these subcontractors were engaged following a competitive tender process. Accordingly, the AER has reviewed the proposed contract rates by benchmarking the rates (and resulting proposed prices) against similar contract rates and proposed prices submitted by the other Victorian DNSPs.

Jemena's submitted contract rates for Skilltech appear reasonable when considering the resulting prices as compared to the prices for similar services provided by the other DNSPs approved in this draft decision. For the service provided by Transfield relating to temporary cover of low voltage mains, this draft decision classifies this service as a quoted alternative control service, and accordingly it is considered in section 20.7.2.

The AER's analysis of the contract rate for services provided by Formway (various manual meter equipment tests)[82] found that the rate results in service prices that are significantly higher than prices calculated by the AER for the other Victorian DNSPs using a reasonable range of labour charge out rates and times taken, based on Impaq's advice. The AER considers that the Formway contract rate proposed by Jemena is substantially higher than rates for similar services carried out by the other Victorian DNSPs. Accordingly, the AER rejects Jemena's proposed prices for meter tests and requests a transparent breakdown of the Formway charge, or a new cost build up for these services. The AER has not approved prices for Jemena's meter testing services in this draft decision.

Profit margins

As noted above, Jemena outsources a large proportion of its business operations to JAM, which is provided for within an integrated Asset Management Agreement (AMA). Alternative control services are included in the AMA.[83] Both Jemena and JAM are 100 per cent owned by Jemena Limited, which is 100 per cent owned by Singapore Power International Pty Ltd. Accordingly, Jemena and JAM are considered related parties.[84] JAM outsources call centre and billing services to Aegis Services Australia (UCMS), which is not considered a related party to Jemena or JAM.[85] JAM also outsources its alternative control services to other parties, however the AER was not provided with details of these further outsourced subcontractors.

Jemena's contract with JAM provides that JAM is entitled to a profit margin for the provision of all services, including alternative control services. Included in the margin is an incentive payment which is returned to Jemena if JAM fails to meet service performance measures determined within the AMA.[86] Jemena has advised the AER that should JAM fail to meet the service performance measures, the incentive payment

81 ibid.

82 The AER notes that these are manual services, which will decline with the AMI rollout and be replaced by remote services.

83 Jemena, *Regulatory proposal*, *Appendix 17.1 Related parties*, p. 2.

84 ibid., p. 1.

85 Jemena, *Regulatory proposal*, *Appendix 16 - Pt 1.*

86 Jemena, *Regulatory proposal appendix 17.1 Related parties*, p. 25.

returned to Jemena would be needed to cover associated cost overruns in areas where JAM failed to meet the performance measures.[87]

As discussed previously, the AER has considered the issue of related party margins included within proposed prices for alternative control services, consistent with the AER's general approach to considering related party transactions outlined in chapter 6 of this draft decision. The AER has found that Jemena's contract with JAM does not pass the presumption threshold, as Jemena had an incentive to enter into a non-arms length contract with JAM due to the relationship between the two companies. The AER also notes that Jemena did not conduct a competitive tendering process when seeking to outsource the provision of its alternative control services.

Accordingly, the AER has considered Jemena's contract with JAM under stage two of its approach to assessing outsourced transactions, detailed in chapter 6. Similar to the finding for CitiPower's and Powercor's proposed alternative control services, discussed above, the AER found that it may be efficient for Jemena's alternative control services charges to incorporate an explicit profit margin. This is because in the absence of an EBSS for alternative control services, there is no mechanism to reward efficiencies generated during the current regulatory control period beyond 2010.

The AER notes that in order for it to allow Jemena to recover a profit margin on alternative control services prices in the 2016–20 regulatory control period, Jemena would need to demonstrate incremental efficiencies gained during the forthcoming regulatory control period.

Accordingly, the AER's draft determination approved prices incorporate a labour charge out rate which includes a 3 per cent profit margin that it considers reasonable for the provision of alternative control services.

Price path—fee based services

For most of its alternative control services, Jemena proposed a price path where each year charges are adjusted by (1+CPI)(1–X), where X reflects the escalation of cost inputs to the service in real terms. Jemena calculated different X factors for each year of the forthcoming regulatory control period by breaking down the costs of the services into individual labour and material components and applying labour and materials escalators, forecast by BIS Shrapnel and SKM respectively.[88]

In determining Jemena's X factors for its form of control for fee based alternative control services, the AER considers it appropriate that Jemena input the labour and materials escalators the AER has approved for standard control services, outlined in appendix K.

AER conclusion—Jemena's fee based alternative control services 2011 prices and price paths

In conclusion, the AER rejects Jemena's proposed fee based alternative control service prices for 2011.

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[87] AER, *File note of meeting with Impaq Consulting and Jemena*, 2 March 2010; Jemena, *Regulatory proposal appendix 17.1 Related parties*, pp. 23–25.

[88] Jemena, *Regulatory proposal*, p. 219.

Jemena submitted prices for routine new connections during the AER's review. The AER considered Jemena's build up of routine new connection services with regard to Impaq's advice on reasonable rates and times. Based on the advice provided by Impaq, the AER rejects Jemena's proposed prices for routine new connections.

The AER has made the following adjustments to Jemena's proposed fee based alternative control service prices for 2011:

- applied the high point of business and after hours line worker hourly charge out rates recommended by Impaq, after reducing the rate to account for a 3 per cent profit margin
- for Jemena's scheduling team rates, applied the midpoint between Impaq's recommended back office rate and line worker rate where appropriate
- where the proposed times were found to be above the reasonable range determined by Impaq, applied the high point of the times taken to perform alternative control services
- in equating the approved prices to 2011 dollars (from 2008 dollars as submitted by Jemena), the AER has applied the same labour and materials escalators it applied to standard control services in this draft decision, as set out in appendix K.

The AER also rejects Jemena's proposed prices for manual meter equipment tests, as it considers the Formway contract rate included within the build up of the proposed prices has not been appropriately justified.[89] The AER requests further information from Jemena on the costs of providing meter equipment test services.

The AER requests that Jemena submit proposed prices for new connections services where Jemena is not the responsible person for metering, for application in 2014 and 2015, as discussed above.

The AER has not approved prices for Jemena's proposed remote metering services, as these services are to be regulated as excluded services under Jemena's distribution licence and Guideline 14, as required by the revised Order.

The AER's draft determination on Jemena's fee based alternative control services prices for 2011 is set out in appendix O.

The AER requests that Jemena input the labour and materials escalators the AER has approved for standard control services (set out in appendix K) in calculating the X factors for its form of control, as part of its revised regulatory proposal.

SP AusNet

As noted previously, the Victorian DNSPs have taken differing approaches to calculating proposed prices, varying between a bottom up build up of the prices of all alternative control fee based services or calculating prices using a top down approach

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[89] The AER notes that these are manual services, which will decline with the AMI rollout and be replaced by remote services.

with current prices as a starting point. The Victorian DNSPs have also used different approaches in building up input costs for services.

SP AusNet used an incremental cost model to calculate its proposed prices for field officer visits, new connections and service truck visits. SP AusNet's proposed meter equipment test service prices are identical to current (2010) prices.

SP AusNet proposed to remove three of its current alternative control services and proposed three of its current alternative control services become quoted services for the forthcoming regulatory control period. Accordingly, SP AusNet proposed that only routine connections, field officer visits, service truck visits and meter equipment tests be fee based alternative control services for the forthcoming regulatory control period.

Similarly to Jemena, SP AusNet did not propose charges for new connections services where it is not the responsible person for metering, and noted a derogation (rule 9.9B of the NER) which requires that the Victorian DNSPs are responsible for all customers' (consuming less than 160MWh per annum and without a type 1 or 2 meter) meters from 1 July 2009.[90] The AER notes that clause 9.9B.2 of the NER requires that the derogation is to expire on the earlier of 31 December 2013 or the commencement of other associated amendments to the NER.[91] As the forthcoming regulatory control period extends beyond 31 December 2013, the AER considers that the Victorian DNSPs will need to have charges for new connections where the DNSP is not the responsible person for the regulatory years 2014 and 2015. Accordingly, the AER requests that SP AusNet submit proposed charges for new connections where it is not the responsible person for metering, to apply in 2014 and 2015, as part of its revised regulatory proposal.

SP AusNet's methodology for establishing prices

In deciding how to calculate its proposed prices for alternative control services, SP AusNet identified new connections, field officer visits and service truck visits as 'material' services, having revenue greater than $50,000 per annum, and accordingly focussed its analysis on the determination of prices for these services.[92] SP AusNet used an incremental cost model to support the calculation of its proposed prices for these high volume services. Proposed manual meter equipment test prices were not amended from current (2010) prices. The AER notes that these services are manual, and are expected to decline as the AMI rollout continues, being replaced by remote services. Charges for remote services are to be regulated as excluded services, as required by the revised Order and discussed in section 20.4.1.

SP AusNet's regulatory proposal stated that only the direct costs associated with providing alternative control services have been included in determining the prices for these services.[93] However, in discussions with the AER, SP AusNet corrected this

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90 SP AusNet, *email to AER staff*, 8 February 2010.
91 NER, cl. 9.9B.2(a) and (b).
92 AER, *file note of meeting with SP AusNet and Impaq Consulting*, 25 February 2010.
93 SP AusNet, *Regulatory proposal*, p. 374.

statement, noting that some capitalised overheads are allocated to its field officer visit prices, however no other overheads are allocated to alternative control services.[94]

In calculating its proposed prices for the three material fee based alternative control services (new connections, field officer visits and service truck visits), SP AusNet applied the following general methodology:

1. The current costs (labour rates and any materials) of carrying out the service in 2009 in each of SP AusNet's central, northern and eastern regions are determined
2. The number of jobs is forecast separately for each of the central, northern and eastern regions for 2010–2015
3. The 2009 input costs are escalated by CPI and labour escalators for each year over 2010–2015
4. Revenue for each service for 2011–2015 is calculated by multiplying the escalated costs for the service by the forecast number of jobs
5. Forecast revenue for each of the central, northern and eastern regions is summed for each year from 2010–2015
6. Using a discount rate of 7 per cent, the net present value (NPV) of the revenue and jobs over the period is calculated [95]
7. Final prices for each service are determined by dividing the NPV of revenues by the NPV of forecast jobs numbers.

Variations to this general methodology for each of new connections, field officer visits and service truck visits are outlined in the following sections.

Field officer visits

SP AusNet’s proposed price for field officer visits is based on the average historical cost of providing field officer visits for the period January 2008 to September 2009, as extracted directly from SP AusNet’s financial system. To translate these historical costs into forecast prices, labour cost escalation and assumptions regarding the forecast number of visits for the forthcoming regulatory control period were applied.

SP AusNet's proposed price for field officer visits applies to customers (or retailers) seeking the following specific services:

- reconnection (fuse insertion for a new customer)
- customer transfer between retailers
- fuse removal (for any purpose as requested by the customer, the customer's retailer, or electrical contractor)

[94] AER, *file note of meeting with SP AusNet and Impaq Consulting*, 25 February 2010.

[95] SP AusNet, *email to AER staff*, 8 February 2010. SP AusNet stated that using NPV costs / NPV jobs is the only way it can calculate a unit price that when applied to the actual jobs in each year will deliver a flow of revenues that, in NPV terms, exactly equals the costs of providing that service, again, in NPV terms.

- provision of general information on the nature of a customer's usage (for example residential, small commercial, large commercial).

To calculate the cost of providing field officer visits over the forthcoming regulatory period, SP AusNet escalated its historical costs, based on extracts from its financial system, for each year of the forthcoming regulatory control period. A labour / material split of 84 per cent was used to derive a weighted real labour escalator applied to historical costs.[96]

The forecast cost is based on SP AusNet's forecast of the number of field officer visits by region for both normal and after hours. This forecast is based on the National Institute of Economic and Industry Research (NIEIR) customer number forecasts, as well as assumptions regarding the roll out of AMI meters and the average proportion of new customers connecting in each of SP AusNet's regions.[97] The proportional customer growth rates for each region were used to split the total growth in customers provided by NIEIR into different regions, which in turn was used to escalate the number of field officer visits in each region. SP AusNet assumed a cumulative customer growth for each year of the regulatory control period, with 78 per cent occurring in the central region, and 14 per cent and 8 per cent in the eastern and northern regions respectively.[98]

Table 20.9 sets out the modelling assumptions SP AusNet used to calculate its field officer visit costs.

Table 20.9 SP AusNet proposal—field officer visits—model assumptions (per cent)

Assumptions	2010	2011	2012	2013	2014	2015
Labour / material split	84.1	84.1	84.1	84.1	84.1	84.1
In-sourced real labour escalator	3.4	2.9	2.6	2.7	2.6	2.4
Weighted cumulative real labour escalator	102.8	105.3	107.6	110.1	112.5	114.8
CPI (Sept 09 / Sept 08)	101.3	–	–	–	–	–
Forecast customer growth	1.8	1.8	1.6	1.4	1.4	1.6
Cumulative customer growth	101.8	103.7	105.3	106.7	108.2	109.9

Source: SP AusNet, *Regulatory proposal*, 30 November 2009 (Attached model–Elec Excl Serve Billing History 0ct 2009).

SP AusNet forecast that the average incremental per unit cost of providing field officer services would increase in the initial years of the AMI rollout program. This is

96 ibid. SP AusNet indicated that the labour /material split was calculated by adding the total labour costs to the total salary costs and dividing this by the total costs of providing field officer visits.

97 ibid. SP AusNet indicated that these calculations are based on the last three years' customer numbers (as per the comparative report).

98 ibid. SP AusNet stated that these proportions are based on the last three years' customer numbers (as per the Comparative Performance Report), 78 per cent of all new customers connecting to SP AusNet's network were within the central region, 14 per cent connected within the eastern region, while the remainder connected within the northern region.

because, in the initial years, the AMI rollout program primarily affects the number of field officer visits conducted in the central region, which is the lowest cost region.[99] Overall, SP AusNet considered that the AMI rollout program would increase the incremental cost to SP AusNet of providing manual field officer services, as a greater proportion of the services are undertaken in the northern and eastern regions of its network, which cost more to service. The AER notes that the manual services will decline as the AMI rollout continues, being replaced by remote services which are facilitated by AMI. This draft decision does not deal with remote services charges, which will be regulated as excluded services, as required by the revised Order and discussed in section 20.4.1.

Routine new connections and service truck visits

The provision of service truck visits and manual new connections in SP AusNet's central region are outsourced to its provider, Tenix Alliance Pty Ltd (Tenix). Tenix is not considered a related party to SP AusNet, however the AER notes that the tendering process resulting in SP AusNet's contract with Tenix was not competitive. In SP AusNet's northern and eastern regions, service truck visits and new connections are provided in-house by SP AusNet.

Connection services apply to customers requiring manual connection of a new premises to the network. This service includes the provision of a service cable in areas with overhead supply and making a connection in a pit for customers in underground supply areas, or where a customer requests an underground connection in an overhead supply area. Underground connection services are classified as quoted alternative control services, and considered in section 20.7.2.

Service truck visits are provided to customers, retailers and other parties seeking the following range of services:

- fuse removal or insertion, where supply is greater than 100 amps
- supply alterations, additions and upgrades to services and installation assets.

SP AusNet proposed that a wasted truck visit should apply when a service truck visit has been arranged and dispatched to a customer's site, and for reasons outside SP AusNet's control, the service truck visit is no longer required.[100]

The costs of providing new connections and service truck visits for SP AusNet's central region are based on SP AusNet's 2008–09 contract with Tenix. For service truck visits, SP AusNet escalated the Tenix contract rates to estimate 2009 costs.[101] Similarly, to estimate its 2010 costs for service truck visits, the 2009 rates were

99 SP AusNet's AMI rollout program involves meters being installed in its central region in the early years of the rollout, with the northern and eastern regions meter installations occurring later in the rollout period. Accordingly, due to the new AMI meters negating the need for common field officer services, SP AusNet forecasts fewer field officer visits for the central region than the northern and eastern regions in the beginning of the next regulatory control period.

100 SP AusNet, *Regulatory proposal*, p. 382.

101 SP AusNet, *email to AER staff*, 8 February 2010. The AER notes that this escalation is consistent with information provided to the AER for SP AusNet's 2008–09 contract with Tenix.

escalated. SP AusNet demonstrated to the AER that its escalation is consistent with the Tenix contract.[102]

By contrast, SP AusNet's 2009 costs for new connections are escalated using BIS Shrapnel's outsourced real labour cost escalator of 1.9 per cent, to determine 2010 rates.[103]

In calculating its proposed prices for new connections and service truck visits, SP AusNet did not add any additional profit margin to the Tenix contract price.

SP AusNet stated that although it provides the services in the northern and eastern regions in-house, it does not capture the volumes of services provided, and noted difficulties in allocating service staff time between standard and alternative control services.[104] Accordingly, in calculating proposed prices for new connections and service truck visits in the northern and eastern regions, SP AusNet increased the Tenix contract costs for provision of services in its central region by 30 per cent.

SP AusNet's 30 per cent escalation for the services in its northern and eastern regions reflects the additional travel time required to reach customers in these areas, relative to its central region. SP AusNet noted that whilst the service delivered is basically the same in each region (that is, the physical connection costs and time to undertake the connection), the travel time associated with getting to and from jobs in each region is vastly different, as the customer density is markedly different, and the area serviced by each depot within those regions is also markedly different.[105]

In order to apply the 30 per cent escalation to the central region contractor costs, SP AusNet determined the physical area within each of its three regions, and divided this by the number of depots in each region to determine the area covered by each depot within a region.[106]

To escalate the 2009 costs of providing new connections, as based on the Tenix contract rates for the central region and SP AusNet's costs for the northern and eastern regions, SP AusNet applied the customer forecast and escalation assumptions as set out in table 20.10.

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[102] SP AusNet, *email to AER staff*, 8 February 2010.
[103] SP AusNet, *Regulatory proposal*, (Attached model–Elec Excl Serve Billing History 0ct 2009).
[104] AER, *file note of meeting with SP AusNet and Impaq Consulting*, 25 February 2010.
[105] ibid.
[106] ibid.

Table 20.10 SP AusNet proposed—new connections—model assumptions (per cent)

Assumptions	2010	2011	2012	2013	2014	2015
NIEIR customer number forecasts	–	1.8	1.6	1.4	1.4	1.6
Labour / material split	80	80	80	80	80	80
In-sourced real labour escalator	3.4	2.9	2.6	2.7	2.6	2.4
Cumulative real labour escalator	102.7	105.1	107.3	109.6	111.9	114.0
Out source real labour escalator	3.1	2.4	2.6	3.0	2.5	2.3
Cumulative real labour escalator	102.5	104.4	106.6	109.1	111.3	113.4
Materials escalator (cable)	8.1	2.7	1.8	1.7	1.6	1.4

Note: The in-sourced real labour escalator is used to escalate the northern and eastern region cost of providing the service by SP AusNet, and the outsourced real labour escalator is used to escalate the central region cost of providing the service by Tenix. The AER notes that the materials escalator is not actually an input into SP AusNet's proposed prices.

Source: SP AusNet, *Regulatory proposal*, (Attached model–Elec Excl Serve Billing History 0ct 2009).

SP AusNet's assumed labour / materials split for new connections is based on equivalent weightings in its contract with Tenix. Using this information, SP AusNet back solved the underlying labour and materials weightings for each new connection service provided by Tenix. These weightings for each service were then further weighted by the number of jobs forecast under each connection service, which was used to derive a total labour / materials split for new connections.

To calculate the costs of providing service truck visits in 2009, SP AusNet applied customer number forecasts and escalation assumptions as set out in table 20.11.

Table 20.11 SP AusNet proposed—service truck visits—model assumptions (per cent)

Assumptions	2011	2012	2013	2014	2015
NIEIR Customer number forecasts	1.8	1.6	1.4	1.4	1.6
Labour / material split	50	50	50	50	50
Insourced real labour escalator	2.9	2.6	2.7	2.6	2.4
Weighted cumulative real labour escalator	101.5	102.8	104.2	105.5	106.8
Outsourced real labour escalator	2.4	2.6	3.0	2.5	2.3
Weighted outsourced real labour escalator	101.2	102.5	104.1	105.5	106.7

Note: The in-sourced real labour escalator is used to escalate the northern and eastern region cost of providing the service by SP AusNet, and the outsourced real labour escalator is used to escalate the central region cost of providing the service by Tenix.

Source: SP AusNet, *Regulatory proposal*, (Attached model–Elec Excl Serve Billing History 0ct 2009).

Meter equipment test
Due to the low number of transactions and revenue associated with manual meter equipment tests, SP AusNet did not formulate its proposed prices for these services on the basis of detailed historical cost information.[107]

Meter equipment tests apply where metering data is in dispute, and SP AusNet is requested to conduct a test of the meter at the customer's premises. Where the meter is found to be faulty, SP AusNet proposed that the prepaid charge would be refunded and a replacement meter installed at no charge to the customer.[108] The AER notes that the AMI rollout facilitates remote meter testing, and accordingly the manual meter test requests will decline as the AMI rollout progresses. As noted above, the AER expects that charges for remote services will be a fraction of charges for manual services, as the labour needed to carry out the remote services is negligible. Charges for remote services are to be regulated as excluded services, as required by the revised Order and discussed in section 20.4.1.

SP AusNet proposed that its 2011 prices for meter equipment test be equal to current (2010) prices.[109]

Customer number inputs
The AER has reviewed the forecast numbers used by SP AusNet to derive its fee based alternative control services. While the forecast customer numbers used in the models differ slightly to updated NIEIR forecasts, the AER has found these differences to be insignificant in determining SP AusNet's proposed prices.[110] Accordingly the AER accepts SP AusNet's forecast customer numbers used to derive proposed prices.

AER conclusion - methodologies for calculating prices
The AER considers SP AusNet's methodologies for calculating prices of field officer visits, new connections and service vehicle visits to be reasonable, however notes that they do not constitute a cost build up. As such, SP AusNet's proposed prices are considered to be reliant on top down adjustments, incorporating contract prices, historical total costs and forecast job numbers.

The AER has considered the information submitted within SP AusNet's price models, and compared it to the advice provided by Impaq on the reasonable charge out rates and times for providing alternative control services. This is discussed below.

Labour and materials escalators

SP AusNet's proposed alternative control services prices incorporate general outsourced and internal labour escalators provided by its consultant, BIS Shrapnel. While SP AusNet's model calculating proposed prices for routine new connections

107 SP AusNet, *Regulatory proposal*, p. 384.
108 ibid., p. 385.
109 ibid., p. 384. The AER notes that SP AusNet's proposed prices within its alternative control services model are presented on a GST exclusive basis, however the AER has assumed that the prices for meter equipment tests within its regulatory proposal, on p. 385, were proposed on a GST inclusive basis.
110 NIEIR, *Electricity sales and customer number forecasts for the SP AusNet distribution region to 2019 (class and network tariff)*, November 2009.

appeared to incorporate its materials escalators for the regulatory years 2012–15, upon analysis of the model the AER considers the materials escalators are not an input into SP AusNet's proposed prices for alternative control services.[111]

Consistent with the approach to approving prices for Jemena, in determining prices for SP AusNet's alternative control services as part of this draft decision, the AER has applied the labour escalators it has approved for standard control services as part of this draft decision, set out in appendix K. Table 20.12 below outlines the AER approved escalators for SP AusNet.

Table 20.12 AER approved outsourced labour and materials escalators for SP AusNet (per cent)

	2011	2012	2013	2014	2015
Insourced labour	0.94	0.99	0.86	1.93	1.46
Outsourced labour	0.87	1.48	1.89	1.87	0.69

Source: Appendix K.

Labour, time and materials inputs

As described above, SP AusNet's methodology for calculating its proposed alternative control services prices varies significantly from the bottom up cost build up carried out by CitiPower, Powercor and Jemena.

As set out in section 20.6 of this chapter, Impaq advised the AER on a reasonable range of labour charge out rates and times taken to perform alternative control services in Victoria. Impaq also advised the AER of a reasonable range of time inputs for providing each component of labour for each of the top seven alternative control services.

The AER considers that any differences in the nature of the Victorian DNSPs' regions, contracting and in-sourcing arrangements should be accounted for within that reasonable range of charge out rates and times. The AER considers that travelling longer distances to provide alternative control services for some DNSPs (due to the relative sizes of the networks) is offset by differences in traffic volumes and parking restrictions in areas where travel distances are shorter. Greater travel distances are also offset by the location of regional service providers and depots that are typically spread across the larger networks.

Overall, the AER considers that it is reasonable to assume that the Victorian DNSPs are able to provide similar alternative control services at similar costs within an efficient range. However, the AER notes that there may be some differences in the specific services provided by each DNSP, which are not accounted for by the range of reasonable prices determined using Impaq's recommended charge out rates and times. Accordingly, the AER has applied the high end of Impaq's recommended range of labour and time inputs in determining prices for CitiPower, Powercor and Jemena.

111 The AER notes that while SP AusNet's model listed its proposed materials escalators, the escalators were not linked to SP AusNet's proposed prices for new connections.

As SP AusNet did not provide a build up of costs for alternative control services, the AER is unable to directly apply Impaq's recommended labour and time inputs to SP AusNet's fee based services cost models. However, the AER has used its draft decision fee based service prices for CitiPower, Powercor and Jemena, which incorporate Impaq's advised rates and times, to generate a reasonable range for each fee based service price. The AER has then compared SP AusNet's proposed fee based prices to that reasonable range, and where necessary adjusted SP AusNet's prices to meet the high point of that reasonable range. The AER considers that the resulting draft decision prices for SP AusNet's fee based services reflect the reasonable costs which would be incurred in the provision of these services, having regard to the advice provided by Impaq.

Profit margins

As described above, SP AusNet's network is divided into three main regions: central, northern and eastern. In its central region SP AusNet outsources the provision of service truck visits and new connections to Tenix through a broad Electricity Distribution Agreement. For central region field officer visits, and northern and eastern regions services, SP AusNet provides the alternative control services in house.

Profit margins - Tenix provided services

SP AusNet's regulatory proposal states that Tenix is not considered a related party as per legal or corporate definitions.[112] The AER's consideration of SP AusNet's broader corporate relationship with Tenix, and profit margins incorporated into the contracts between SP AusNet and Tenix, is provided in chapter 6 of this draft decision.

SP AusNet's contract with Tenix does not explicitly determine a profit margin or management fee. However, SP AusNet has indicated that it expects the prices Tenix tendered for the provision of alternative control services would incorporate some profit margin for Tenix, although SP AusNet is unaware of what proportion of the Tenix price is profit.[113]

The AER's draft decision, set out in chapter 6, is that the profit margins paid by SP AusNet to Tenix for standard control services are not inefficient. The same analysis has been applied to profit margins paid by SP AusNet to Tenix for alternative control services.

DNSP profit margins— in house provided services

For all field officer visits, and all alternative control services provided in the northern and eastern regions of SP AusNet's network, SP AusNet provides the services in house. As outlined above, the prices for field officer visits do not incorporate a profit margin for SP AusNet. As prices for new connections and service vehicle visits in the northern and eastern regions are based on the Tenix prices for the central region (but increased to account for the additional costs of providing services in those regions), these services do not explicitly incorporate a profit margin. SP AusNet's proposed 2011 prices for its manual meter equipment tests are equal to current (2010) prices, for which the AER was not provided underlying cost information. Accordingly no explicit profit margin is discernable.

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112 SP AusNet, *Regulatory proposal—Related Party Arrangements*, p. 37.
113 AER, *file note of meeting with SP AusNet and Impaq Consulting*, 25 February 2010

SP AusNet may be recovering some profit from the alternative control services it provides in house, however the price build up performed by SP AusNet does not reveal the proportion of profit.

AER conclusion—profit margins

Following the analysis of CitiPower's and Powercor's profit margins in accordance with the approach set out in chapter 6 above, the AER considers it is reasonable for SP AusNet to recover a profit margin on alternative control services prices over the forthcoming regulatory control period.

The AER's draft decision approved prices for SP AusNet are benchmarked against prices which incorporate a labour charge out rate recommended by Impaq which is inclusive of a profit margin that the AER considers reasonable for the provision of such services. In this way, the AER considers that it is allowing SP AusNet and its contractors a reasonable profit for the provision of alternative control services.

Price path—fee based services

SP AusNet proposed to apply the following price path for its alternative control services for each year of the forthcoming regulatory control period:

$P_t \leq P_{t-1} \times (1+CPI) \times (1-X)$, where X = 1 per cent[114]

The AER considers that SP AusNet's proposed price path is consistent with the form of control set out in the Framework and approach paper.

The AER accepts SP AusNet's proposed form of control for its fee based alternative control services.

AER conclusion—SP AusNet's fee based alternative control services 2011 prices and price paths

The AER has analysed SP AusNet's models for alternative control services prices, and considered SP AusNet's proposed prices as compared to prices determined for the other Victorian DNSPs for each service based on Impaq's advice.

The AER considers it efficient for SP AusNet to provide its alternative control services within the reasonable price range determined for the other Victorian DNSPs' services. The AER notes that this reasonable price range incorporates labour escalators which are consistent with those approved for standard control services.

The AER found that generally, for the services for which SP AusNet applied its cost models, the proposed prices were comparable to the AER determined prices for the other Victorian DNSPs, with the exception of the proposed price for after hours service truck visits.

The AER accepts SP AusNet's proposed 2011 prices for meter equipment tests, which are equal to current (2010) prices and are within the benchmark reasonable range of prices calculated for CitiPower, Powercor and Jemena.

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[114] SP AusNet, *Regulatory proposal*, p. 395.

In summary, the AER has made the following adjustment to SP AusNet's proposed prices:

- applied labour escalators as outlined in appendix K to SP AusNet's price models for field officer visits, new connections and service vehicle visits to determine an adjusted price.

The AER has not approved a price for after hours service truck visits, and requests further information from SP AusNet on the costs of providing this service as part of its revised regulatory proposal such that a cost build up using Impaq's recommended labour charge out rates and times can be undertaken.

The AER requests that SP AusNet submit proposed prices for new connections services where SP AusNet is not the responsible person for metering, for application in 2014 and 2015, as discussed above.

The AER's draft determination on SP AusNet's fee based alternative control services prices is set out in appendix O.

The AER accepts SP AusNet's proposed form of control for its fee based alternative control services.

United Energy

United Energy's methodology for establishing prices

United Energy's regulatory proposal stated that its proposed prices for fee based alternative control services for the forthcoming regulatory control period are based on prices submitted by the winning consortium bidder (winning bidder) in a competitive tender process undertaken by United Energy to outsource all of its services (standard and alternative control) from July 2011.[115] United Energy provided a significant volume of information on its tendering process, which is considered in relation to standard control services in chapter 6. However, United Energy did not provide information on the underlying costs of providing its fee based alternative control services, as this information was not provided to United Energy by the winning bidder. Accordingly, unlike the approach applied to standard control services, the AER has not been able to undertake a revealed cost approach to reviewing United Energy's alternative control services prices. Instead the AER has relied on benchmarking United Energy's proposed prices against the reasonable range of prices, as discussed above.

Allocation of overheads

In estimating prices for its fee based alternative control services, where possible, United Energy allocated its direct (winning bidder contractor) costs to the services. United Energy has also allocated corporate overheads and other relevant costs, consistent with its cost allocation methodology, to individual services in calculating proposed prices.[116]

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115 United Energy, *Regulatory proposal appendix C-2*, p. 51.
116 ibid., p. 35.

United Energy provided a model to support its calculation of final prices for its fee based alternative control services. The model takes the prices submitted by the winning bidder for each service and adjusts them to allocate a proportion of overheads.[117]

To allocate its overheads to individual alternative control services, United Energy calculates its revenue requirement (winning bidder price multiplied by forecast volumes) for each service, as a proportion of the total revenue required for all alternative control services. This proportion is multiplied by the total revenue required for all alternative control services (which includes a proportion of the shared costs). This results in adjusted revenue for each service. The adjusted revenue is divided by forecast volume to determine a price which includes the shared costs. The result is in an upward adjustment of the winning bidder's submitted price.

The proportion of United Energy's overhead costs allocated to alternative control services is based on its 2008 regulatory accounts.[118] However, the allocation of shared costs forecast for the forthcoming regulatory control period, based on the process described above, results in a greater increase to the winning bidder prices than suggested by the 2008 regulatory account overhead allocations. A decrease in forecast volumes for the services over the forthcoming regulatory control period, and the winning bidder prices which in most cases are lower than the current (2010) prices, have resulted in a corresponding decrease in the forecast revenue from alternative control services compared to the current regulatory control period. As a result, the proportion of overhead costs allocated to alternative control services constitutes a greater proportion of total overhead costs in the forthcoming regulatory control period, than in the current regulatory control period.

United Energy's prices for routine new connections also include the costs of United Energy's new connections front desk team, as proposed by the winning bidder.[119]

Calculation of forecast volumes

United Energy’s forecast volumes for its alternative control services are important in its derivation of overheads applying to the final proposed prices. For many of its services, United Energy forecast similar volumes for the forthcoming regulatory control period compared to the current regulatory control period. However, for some services United Energy has forecast a significant change in the number of services provided over 2011–15, including:

- field officer visits—78 per cent decrease from the current regulatory control period
- service truck visits—12 per cent decrease from the current regulatory control period

117 United Energy shared costs include CEO, strategic planning, CFO, Human resources, regulation, IT, Audit services, call centre and property rates costs.

118 United Energy *Regulatory proposal* (Attached model—New Prices Calculations), 30 November 2009.

119 United Energy, *email to AER staff,* 16 March 2010.

- meter equipment test—17 per cent decrease from the current regulatory control period

- new connections—6 per cent decrease from the current regulatory control period.

United Energy stated that it expects its field officer visits will decrease in volume as AMI meters are rolled out and services are completed remotely, while service truck visit volumes will also decrease as United Energy is better able to communicate with its customers through the additional information provided by AMI meters.
United Energy also noted that the AMI rollout is expected to result in fewer faults on its new equipment.[120]

For new connection services, United Energy's forecast is in line with its customer number forecasts developed by NIEIR and considered in chapter 5 of this draft decision.

Further adjustments to winning bidder prices
In addition to the adjustments outlined above for the allocation of its overheads and front desk costs for new connections, United Energy proposed the following increases to the winning bidder prices:

- prices of certain after hours services were inflated to discourage customers from requesting these services[121]

- where United Energy's analysis of the change from the current (2010) price to proposed winning bidder prices revealed a significant reduction, the winning bidder prices were either increased by $100, or adjusted to equal current (2010) prices, to account for expected differences in the winning bidder's proposed services and current services.[122]

In summary, United Energy makes two adjustments to the winning bidder contract prices. The first adjustment reflects the allocation of shared costs (as discussed above) and the second (further) adjustment reflects the inflation of prices to either discourage after hour services or to account for differences between the winning bidder price and the current price.

The AER considers that United Energy's proposed approach of inflating its direct costs specifically to discourage customers from requesting after hours services means that the proposed prices are not cost reflective. United Energy's underlying costs are established by the winning bidder proposed prices, plus the overhead allocation under its cost allocation methodology. The additional arbitrary disincentive adjustment moves United Energy's prices away from cost reflectivity, which the AER considers to be inefficient.

Similarly, United Energy's arbitrary inflation of winning bidder contract prices has not been sufficiently justified, affecting the following normal hours services:

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120 United Energy, *email to AER staff*, 15 February 2010.
121 United Energy, *email to AER staff*, 16 March 2010.
122 ibid.

- temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—BH; and
- temporary supplies (exc. inspection)—independent disconnection—multiphase to 100A—BH.

Accordingly, the AER has removed United Energy's proposed inflation of winning bidder contract prices (designed to discourage customers from requesting the services) in approving fee based alternative control service prices for this draft decision. The AER considers the adjustments made by United Energy to the winning bidder price in order to allocate overhead costs, as described in this section, are reasonable.

AER conclusion—methodologies for calculating prices
The AER notes United Energy's methodology for calculating alternative control services prices is reasonable, however notes that it does not directly constitute a cost build up, as United Energy did not base the prices on times taken to perform services and labour rates, but rather it based prices on its direct contract costs and overhead allocations.

Labour, time and materials inputs

As described above, United Energy's methodology for calculating its proposed alternative control services prices varies significantly from the bottom up cost build up carried out by CitiPower, Powercor and Jemena.

As set out in section 20.6 of this chapter, Impaq advised the AER on a reasonable range of labour charge out rates and times taken to perform alternative control services in Victoria. Impaq also advised the AER on a reasonable range of time inputs for providing each component of labour for each of the top seven alternative control services.

As discussed above in relation to SP AusNet, the AER considers that any differences in the nature of the Victorian DNSPs' regions, contracting and in-sourcing arrangements should be accounted for within that reasonable range of charge out rates and times. Overall, the AER considers that it is reasonable to assume that the Victorian DNSPs are able to provide similar alternative control services at similar costs within an efficient range. However, the AER notes that there may be some differences in the specific services provided by each DNSP, which are not accounted for by the range of reasonable prices determined using Impaq's recommended charge out rates and times. Accordingly, the AER has considered the high end of Impaq's recommended range of labour and time inputs to be a reasonable reference point for determining prices for United Energy.

The AER has considered the information submitted within United Energy's price model, and compared it to Impaq's advice on the reasonable range of charge out rates and times for providing alternative control services. In doing so, the AER has found that where United Energy provides similar services to CitiPower, Powercor and Jemena, most of United Energy's proposed prices fall either close to, or below the AER maximum determined price range for these services (as determined on a cost build up using Impaq's recommended labour charge out rates and time inputs).

Exceptions to this include United Energy's proposed 2011 prices for reconnections (normal and after hours) and same day reconnections, which fall just outside the reasonable range of 2011 prices determined using Impaq's recommended labour rates and times. The AER notes that United Energy's proposed price control for fee based services escalates prices by CPI over the forthcoming regulatory control period, compared to price paths proposed by CitiPower, Powercor, and Jemena, all of which escalate 2011 prices by rates that result in a much greater increase by 2015 than that proposed by United Energy. Accordingly, the AER considers that United Energy's proposed 2011 prices for reconnections (normal and after hours) and same day reconnections are reasonable, considering United Energy has proposed no real increases in prices for these services over the forthcoming regulatory control period.

Profit margins

As outlined in its regulatory proposal, during the forthcoming regulatory control period, United Energy is undertaking a business transformation in which its network operations and management outsourcing will undergo significant change.[123] As part of this change, services provided in the current regulatory control period by Jemena Asset Management (JAM) will likely be provided by a new consortium which was the winning bidder in a tendering process. This change includes the provision of alternative control services.

United Energy's proposed prices for alternative control services are based on the winning bidder's proposed prices, plus a proportion of shared overheads (as outlined above). While contracts between United Energy and the winning bidder are not yet finalised, United Energy has informed the AER that its proposed prices do not explicitly incorporate a profit margin for the winning bidder, whose bid was accepted on the basis of competitive prices overall across both standard and alternative control services. However, United Energy acknowledged it is likely that the prices include some profit.[124] Whilst the AER acknowledges that a profit margin has not been explicitly identified for alternative control services, the AER notes that, as set out in chapter 6 of this draft decision, United Energy's overall contract with the winning bidder does set out a margin which includes indirect overheads and a profit component.

United Energy stated that it does not apply any additional profit margin above overhead costs to the winning bidder's alternative control services prices. [125]

The AER's draft decision, set out in chapter 6, is that the profit margins paid by United Energy to the winning consortium for standard control services are not of themselves, inefficient. The same analysis has been applied to profit margins paid by United Energy to the winning consortium for alternative control services. Accordingly, the AER has not removed the related party margins components of United Energy's alternative control services prices.

The AER's draft determination approved prices for United Energy are benchmarked against prices which incorporate a labour charge out rate recommended by Impaq

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[123] United Energy, *Regulatory proposal Appendix C-2*, p. 17.
[124] AER, *file note of meeting with Impaq Consulting and United Energy*, 23 February 2010.
[125] ibid.

which is inclusive of a profit margin that the AER considers reasonable for the provision of such services. In this way, the AER considers that it is allowing United Energy and its contractors a reasonable profit for the provision of alternative control services.

Price path—fee based services

United Energy proposed to apply the following price path for its alternative control services for each year of the forthcoming regulatory control period:

$p_t \leq p_{t-1} \times(1+CPI_t)\times(1-X)$, where $X = 0$[126]

The AER considers United Energy's proposed price path is consistent with the form of control set out in the Framework and approach paper. The AER accepts United Energy's proposed form of control for its fee based alternative control services.

AER conclusion—United Energy's fee based alternative control services 2011 prices and price paths

As discussed above, the AER rejects United Energy's arbitrary inflation of rates for alternative control services. Accordingly, the AER has removed United Energy's proposed inflation of prices for the following services:

- temporary cover of LV mains—two wire cover—AH
- temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—BH
- temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—AH
- temporary supplies (exc. inspection)—independent disconnection—multiphase to 100A—BH
- new connections where United Energy is responsible—single phase single element—AH
- new connections where United Energy is responsible—single phase two element (off peak)—AH
- new connections where United Energy is responsible—three phase direct connected—AH
- new connections where United Energy is responsible—single phase single element—AH
- new connections where United Energy is responsible—single phase two element (off peak)—AH

[126] United Energy, *email to AER staff*, 16 March 2010.

- new connections where United Energy is responsible—three phase direct connected—AH
- service vehicle visits (without inspection) —first 30 minutes—AH.

In considering the advice on appropriate labour charge out rates and times taken for alternative control services, as applied to CitiPower, Powercor and Jemena, the AER has found that the remainder of United Energy's proposed alternative control services prices for 2011 are within a reasonable range, aside from proposed 2011 prices for reconnections (normal and after hours) and same day reconnections. For these services, the AER has considered United Energy's proposed price control formula in light of the price control formulas proposed by CitiPower, Powercor and Jemena, and on balance, having regard to the prices at the end of the forthcoming regulatory control period, considers United Energy's proposed 2011 prices to be reasonable.

The AER's draft determination on United Energy's fee based alternative control services prices is set out in appendix O.

The AER accepts United Energy's proposed form of price control for its fee based alternative control services.

20.7.2 Quoted services

Chapter 2 of this draft decision sets out the classification of alternative control quoted services in the forthcoming regulatory control period, as listed in table 20.13.

Table 20.13 AER conclusion on service classification of alternative control quoted services for 2011-2015 regulatory control period

Quoted alternative control services
Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets
Supply enhancement at customer request
Emergency recoverable works (that is. emergency works where customer is at fault and immediate action needs to be taken by the DNSP)
Auditing of design and construction
Specification and design enquiry fees
Elective underground service where an existing overhead service exists
Damage to overhead service cables pulled down by high load vehicles
High load escorts - lifting overhead lines
Covering of low voltage mains for safety reasons
Routine connections, for customers > 100amps

Source: Appendix B of this draft decision.

Quoted services are services provided at the request of a customer that involve a time commitment from the DNSP, and the costs of which vary depending on the man-hours spent and the materials used in providing the service.

The Framework and approach paper stated that the AER would apply a price cap form of control to regulate quoted alternative control services for the forthcoming regulatory control period. It stated that a price cap formula for all quoted services will apply, where the unit costs of inputs will be capped but not the overall service price. The Framework and approach paper also stated that the Victorian DNSPs would be required to propose an individual formula to calculate the tariff of each quoted service, and submit information and cost inputs in relation to these services.

None of the Victorian DNSPs submitted information on materials costs for quoted services, nor proposed materials price paths. SP AusNet and Jemena proposed materials for quoted services be recovered at cost. In the absence of further information from CitiPower, Powercor and United Energy, the AER considers that customer prices for materials for quoted services should be set at the cost of the materials to DNSPs.

The following discussion considers the Victorian DNSPs' proposed labour costs and associated price paths for quoted services.

CitiPower and Powercor

Based on CitiPower's and Powercor's regulatory proposals and service classifications set out in chapter 2 of this draft decision, quoted services provided by these DNSPs over the forthcoming regulatory control period include:

- emergency recoverable works—BH and AH
- damage to overhead service cables caused by high load vehicles—for both single and multi phase cables, BH and AH
- high load escorts—BH and AH.[127]

In analysing the tasks involved in CitiPower's and Powercor's proposed quoted services, Impaq considered that an appropriate labour classification is that of a distribution line worker.[128] In comparing CitiPower's and Powercor's proposed quoted services labour rates to the charge out rates for line workers, as detailed in section 20.6.2, Impaq found CitiPower's and Powercor's labour rates to be above the reasonable range.

The AER considers that an appropriate hourly labour charge out rate for CitiPower's and Powercor's quoted services is that which is within the reasonable range determined by Impaq's analysis. Consistent with its approach for fee based services outlined in section 20.7.1, the AER considers a reasonable hourly rate for CitiPower's and Powercor's quoted services is the highest point of Impaq's recommended range of labour rates, adjusted to include a 3 per cent profit margin.

The AER has classified the covering of low voltage mains as a quoted service and accordingly requires CitiPower and Powercor to provide labour costs for this service in their revised regulatory proposals. The AER notes that CitiPower and Powercor did

[127] CitiPower, *Regulatory proposal*, p. 386; Powercor, *Regulatory proposal*, p. 392.
[128] Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, p. 42–43.

provide information on materials costs for temporary cover of low voltage mains in their regulatory proposals (as this was proposed by CitiPower and Powercor to be a fee based service). The proposed costs were based on average quantities of materials being required per service. The proposed materials input costs, which included some overhead costs, were assessed by Impaq and found to be reasonable.[129] However due to the service classification change from the Framework and approach paper, the AER requests that CitiPower and Powercor resubmit proposed materials costs, with further details on the overheads to be applied to the costs should they disagree with the AER's draft decision that materials for quoted services are to be recovered at cost.

Price path—quoted services

CitiPower and Powercor proposed their 2011 labour rate be escalated by the BIS Schrapnel labour escalator, plus CPI over the forthcoming regulatory control period.[130]

The AER agrees that it is appropriate to escalate the approved 2011 labour rates for quoted services for years 2012–15, however does not consider it appropriate to escalate the labour rate by CPI in addition to the labour escalator.

The AER approves escalation of the quoted services labour rates by the outsourced labour escalation rates it approved for CitiPower's and Powercor's standard control services, set out in table 20.7 above, and discussed in appendix K.

Jemena

Based on Jemena’s regulatory proposal and service classifications set out in chapter 2 of this draft decision, quoted services to be provided by Jemena over the forthcoming regulatory control period include:

- damage to overhead service cables caused by high loads
- high load escorts
- rearrangement of network assets at customer request (excluding alteration and relocation of existing public lighting services)
- supply enhancement at customer request.

In analysing the tasks involved in Jemena's quoted services, Impaq considered that an appropriate labour classification is that of a distribution line worker.[131] In comparing Jemena's proposed quoted services labour rates to the charge out rates for line workers, as detailed in section 20.7.1, Impaq found Jemena's labour rates to be above the reasonable range.

The AER considers that an appropriate hourly labour charge out rate for Jemena's quoted services is that which is within the reasonable range determined by Impaq's analysis. Consistent with its approach for fee based services outlined in section 20.7.1,

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129 ibid., pp. 53–54.
130 CitiPower, *Regulatory proposal*, p. 385; Powercor, *Regulatory proposal*, p. 391.
131 Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, p. 42.

the AER considers a reasonable hourly rate for Jemena's quoted services is the highest point of Impaq's recommended range of labour rates, adjusted for a 3 per cent profit margin.

Price path—quoted services

Jemena proposed a price path for its quoted services, whereby each year labour rates are adjusted by an X factor. Jemena did not provide a breakdown or explanation of the proposed X factor in its proposal, however the AER understands that this rate is based on BIS Schrapnel labour escalation rates.[132]

Given the approved 2011 labour charge out rate is based on the AER's and Impaq's assessments of a reasonable rate in 2010, the AER considers that it is appropriate to escalate the approved 2011 labour rate for quoted services for years 2012–15. The AER approves escalation of the quoted services labour rate by the outsourced labour escalation rate it approved for standard control services, discussed in appendix K.

SP AusNet

Based on SP AusNet's regulatory proposal and service classifications set out in chapter 2 of this draft decision, quoted services to be provided by SP AusNet over the forthcoming regulatory control period include:

- temporary cover of low voltage mains
- elective underground servicing
- service cable pulled down by high loads.

As noted in section 20.4.2, SP AusNet proposed a range of rates for alternative control services labour classifications, including distribution line workers, drafting officers, technical officers and engineers.

Impaq's analysis of line worker rates for quoted services is consistent with its analysis for fee based services. Impaq concluded that SP AusNet's proposed quoted services rate for line workers is within a reasonable range. Impaq also concluded that SP AusNet's proposed rates for drafting officers, technical officers and engineers are within a comparative range of the rates charged by other DNSPs in the NEM, and were therefore reasonable.[133] The AER agrees that the proposed hourly rates for SP AusNet's quoted services line workers, drafting officers, technical officers and engineers are reasonable.

The AER notes that SP AusNet's regulatory proposal for quoted services included proposed prices for unregulated and negotiated services. As noted previously, the AER has not considered these proposed labour rates, as prices or rates for unregulated and negotiated services are not set by the AER through its regulatory determination for distribution services. The regulatory arrangements for negotiated services are discussed in chapter 3 of this draft decision.

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[132] Jemena, *Regulatory proposal*, p. 243.
[133] Impaq Consulting, *Review of Distributors Proposed Rates in ACS charges*, p. 50.

Price path—quoted services

SP AusNet did not propose a price path for quoted services labour for the forthcoming regulatory control period.

Given the approved 2011 labour charge out rate is based on the AER's and Impaq's assessments of a reasonable rate in 2010, the AER considers that it is appropriate to escalate the approved 2011 labour rates for quoted services for years 2012–15. For consistency with the AER's draft decisions for the other Victorian DNSPs, the AER approves escalation of the quoted services labour rate by the outsourced labour escalation rate it approved for SP AusNet's standard control services, discussed in appendix K.

United Energy

United Energy did not submit any labour or material rates for quoted (recoverable works) services, nor any proposed price path for quoted services labour or materials rates.

United Energy's regulatory proposal included proposed fixed fees for some sub-classifications of the following services, which the AER has classified as quoted services in this draft decision:

- temporary cover of low voltage mains
- elective underground service
- service cable pulled down by high loads.

The AER has not approved the proposed fixed fees for these services, as they are classified as quoted services, and requires United Energy to submit associated labour rates and materials costs as part of its revised regulatory proposal.

Accordingly, the AER has not approved any input prices nor price paths for United Energy's quoted services, and requests that United Energy provide the information necessary for the AER to review quoted services input costs, as part of United Energy's revised regulatory proposal.

20.7.3 Compliance with the control mechanism for alternative control services

Under clauses 6.12.1(12) and 6.12.1(13) of the NER, the AER’s distribution determination must set out a decision on how compliance with the control mechanisms for fee based and quoted alternative control services are to be demonstrated.

In the current regulatory control period, the ESCV is responsible for monitoring the Victorian DNSPs' charges for excluded (alternative control) services, which is undertaken under Guideline 14, within clauses 5.4 to 5.8. Guideline 14 provides that the Victorian DNSPs submit annual statements of proposed charges to the ESCV, which are then assessed under principles set out in clause 5.6. The approved charges are then published on the ESCV's website. For the forthcoming regulatory control period, clauses 5.4 to 5.8 of Guideline 14 will cease to have effect, being replaced by the AER's determination setting out the form of control for alternative control services for the forthcoming regulatory control period.

None of the Victorian DNSPs proposed any methods for demonstrating compliance with the control mechanisms for alternative control services.

The Framework and approach paper stated that the Victorian DNSPs will be required to submit to the AER for approval an initial fee based alternative control price proposal for the first regulatory year of the forthcoming regulatory control period and an annual pricing proposal for each subsequent regulatory year of the forthcoming regulatory control period.[134] The AER considers that this proposal should demonstrate the DNSPs' compliance with the AER's determination on the form of control for the next regulatory year. The annually approved prices for each DNSP's fee based alternative control services, which will accord with the determination, must be published by each DNSP on its respective website.[135]

The Framework and approach paper stated that the unit costs and prices charged for quoted services would be reviewed ex post via the annual pricing proposal process.[136] The AER now considers that it is more appropriate that the unit costs for quoted services (being labour costs and the basis for materials charges) be approved in the same manner as fee based service prices, being that the Victorian DNSPs are required submit an annual proposal on the unit costs for quoted services, demonstrating compliance with the AER's control mechanism. The annually approved unit costs for each DNSP's quoted alternative control services, which will accord with the determination, must be published by each DNSP on its respective website.[137]

The AER considers that the timing of the annual alternative control services pricing proposal process should be consistent with the timing of the annual pricing proposal process for standard control services, in that proposals must be submitted to the AER in accordance with clause 6.18.8 of the NER, being within 15 days of publication of the AER's final determination for prices for the first regulatory year (2011), and for each subsequent regulatory year of the forthcoming regulatory control period, within two months of the end of the regulatory year.

The AER's draft decision is consistent with the Framework and approach paper, in that compliance with the alternative control services control mechanisms will be demonstrated through an annual pricing proposal process, however the AER's draft decision on the approach for quoted services differs from the ex-post process set out in the Framework and approach paper.

20.8 AER conclusion

20.8.1 Fee based services

The AER's draft decision on the Victorian DNSPs' fee based alternative control service charges is the result of analysis of the differing methodologies for calculating

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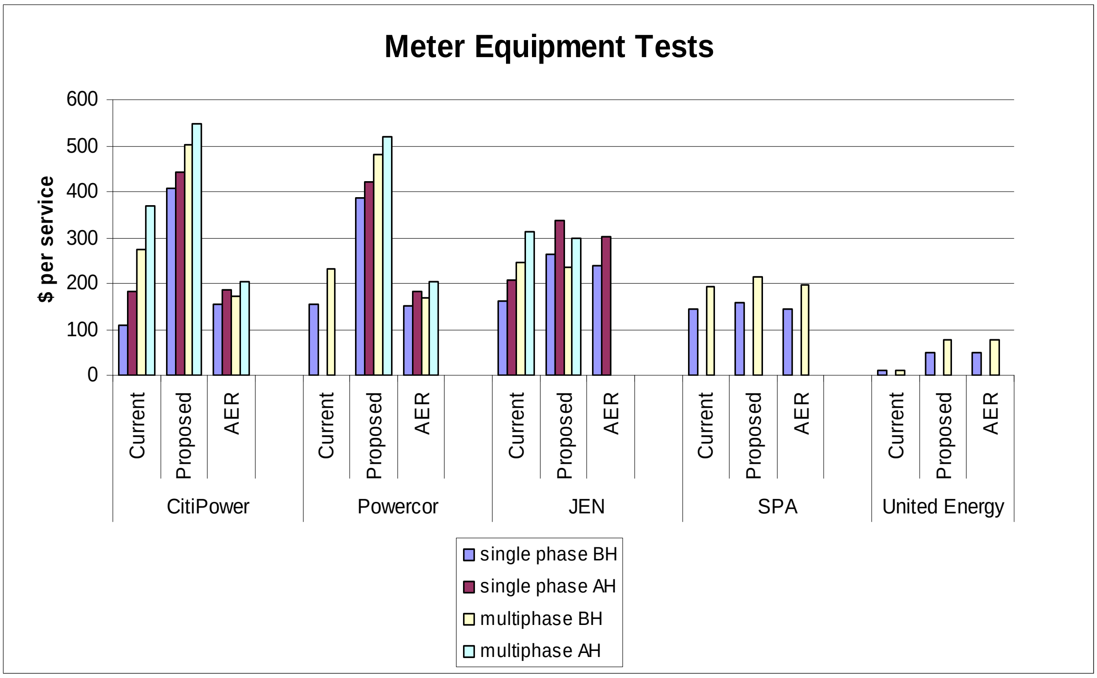
[134] AER, *Framework and approach paper*, p. 79.
[135] NER, cl. 6.18.9.
[136] AER, *Framework and approach paper*, p. 81.
[137] NER, cl. 6.18.9.

proposed prices and advice provided by Impaq on reasonable labour, materials and time inputs.

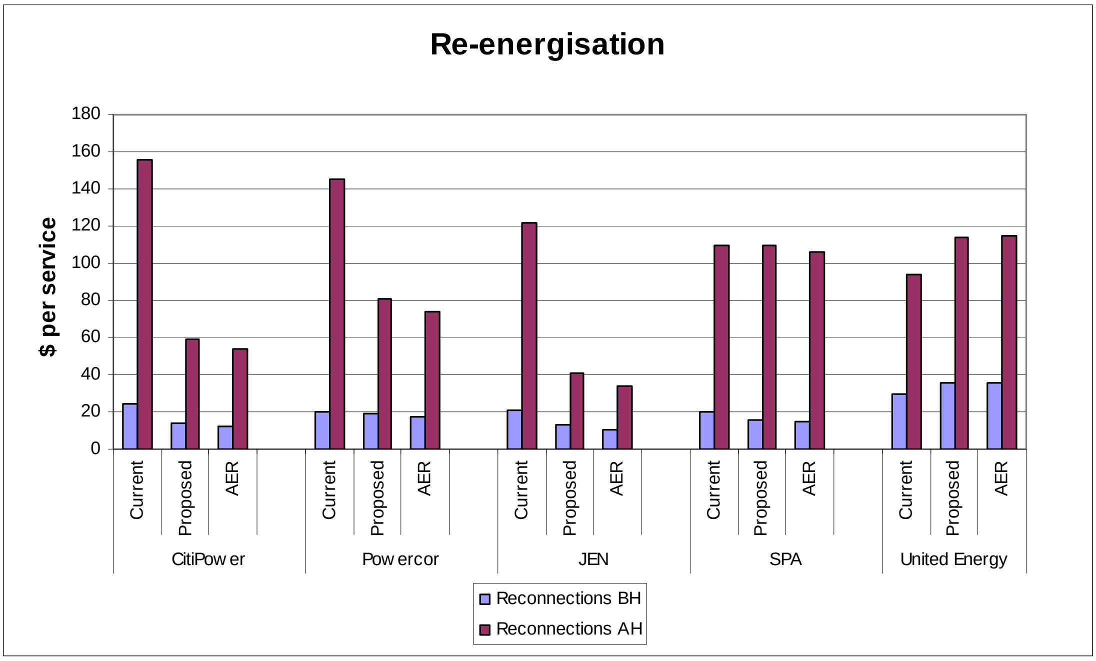
Due to significant variation between the Victorian DNSPs' proposed prices for similar services, as well as the differing methodologies for generating the proposed prices, the resulting draft decision prices vary among the DNSPs for similar services. Figures 20.4 to 20.11 show the current, proposed and AER draft determination prices for the most requested services across the Victorian DNSPs.

Figure 20.4 AER analysis—Meter equipment test—BH and AH ($, 2010)



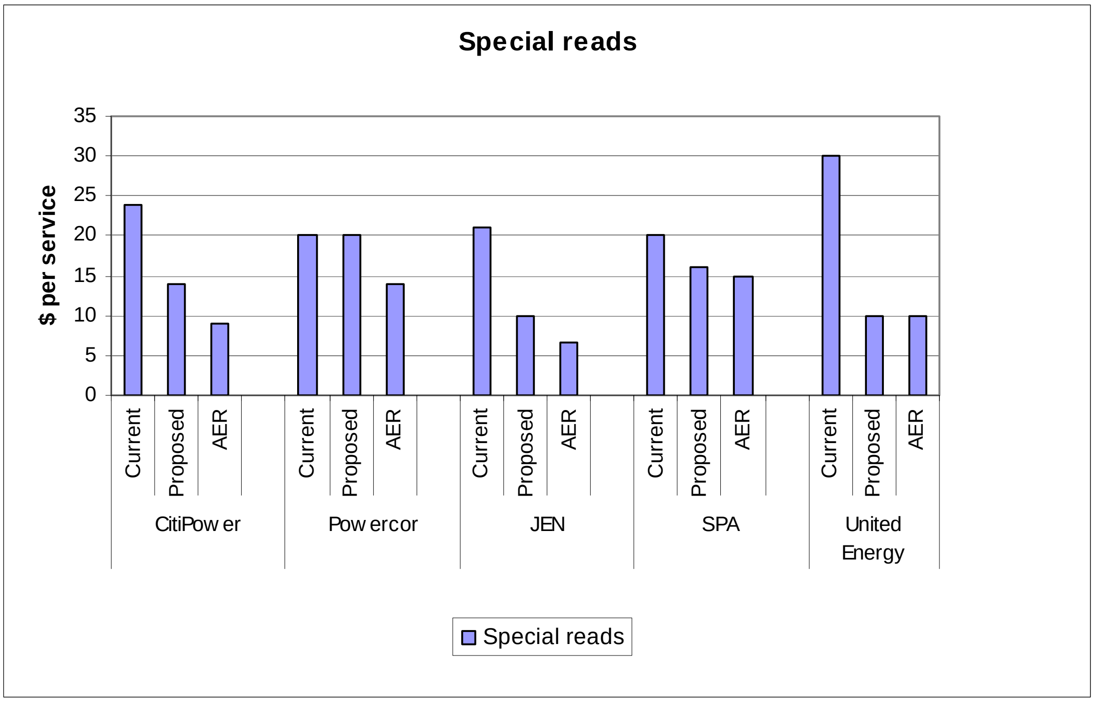
Note: United Energy and SP AusNet did not propose after hour services for meter equipment tests. The AER requests further information from Jemena as part of its revised regulatory proposal on the underlying costs of providing certain meter equipment tests.

Figure 20.5 AER analysis—Re-energisation—BH and AH ($, 2010)



Note: Also known as reconnection (CitiPower and Powercor). While the 2011 proposed price for reconnections for CitiPower and Powercor are low in comparison to the other DNSPs, these DNSPs propose price increases of around 67 per cent for business hours and 92 per cent for after hours by 2015. The AER has not approved these price increases over 2012–15.

Figure 20.6 AER analysis—Special Reads ($, 2010)



Note: This service relates to basic meters. SP AusNet charges a Field officer visit fee to conduct special reads. While the 2011 proposed prices for special reads for CitiPower and Powercor are low in comparison to the other Victorian DNSPs, both propose price increases of around 70 per cent by 2015. The AER has not approved these price increases over 2012–15.

Figure 20.7 AER analysis—Service truck visits—BH and AH ($, 2010)

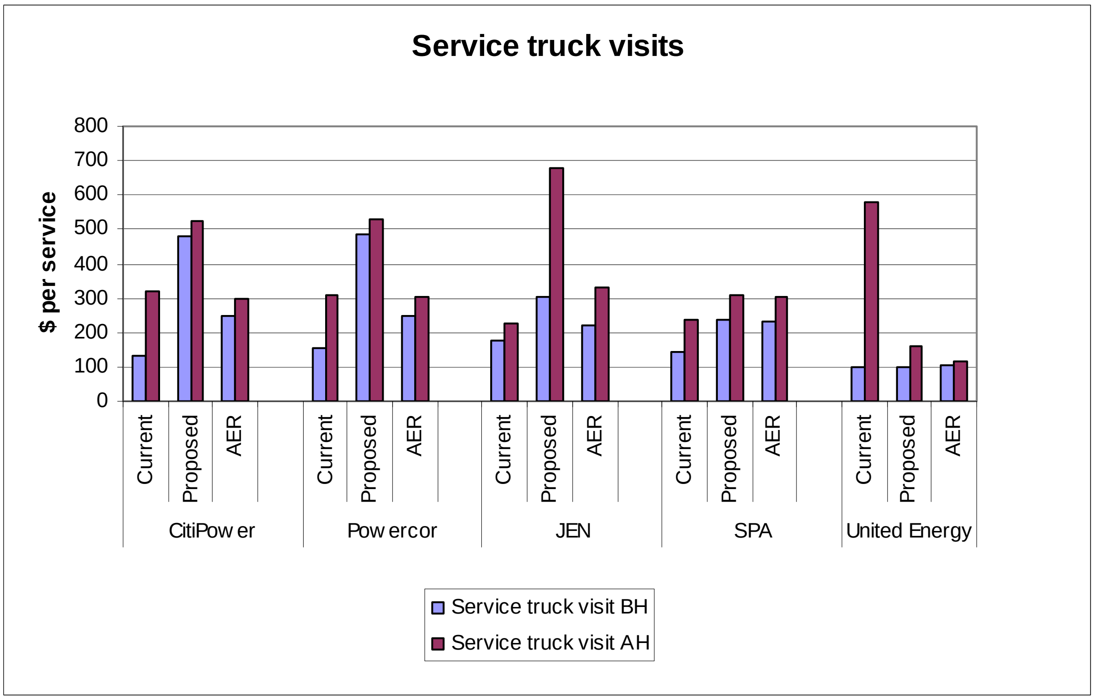


Figure 20.8 AER analysis—Wasted Service truck visits—BH and AH ($, 2010)

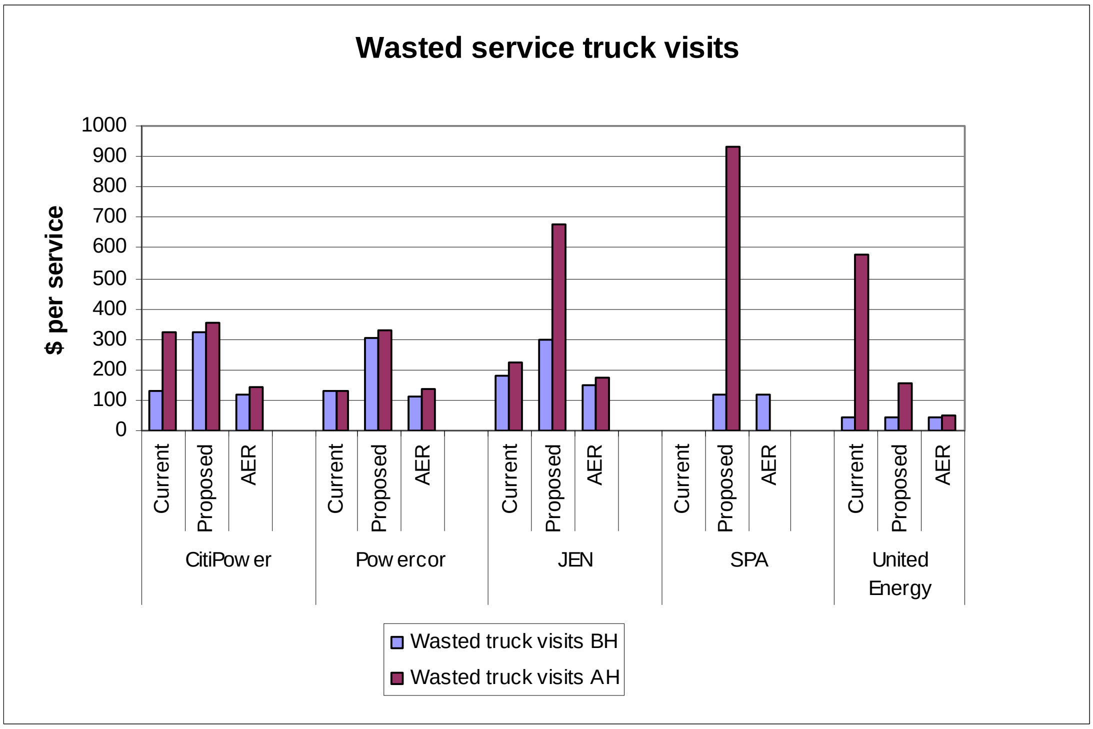


Figure 20.9 AER analysis—Routine new connections single phase—BH and AH ($, 2010)

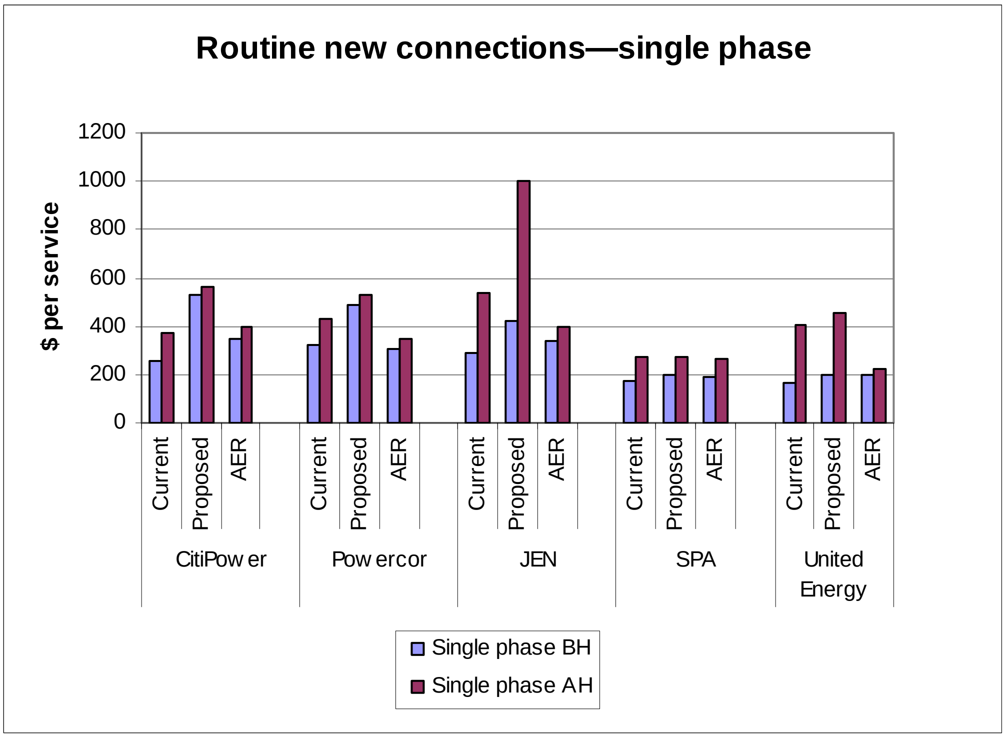


Figure 20.10 AER analysis—Routine new connections multi phase direct connected—BH and AH ($, 2010)

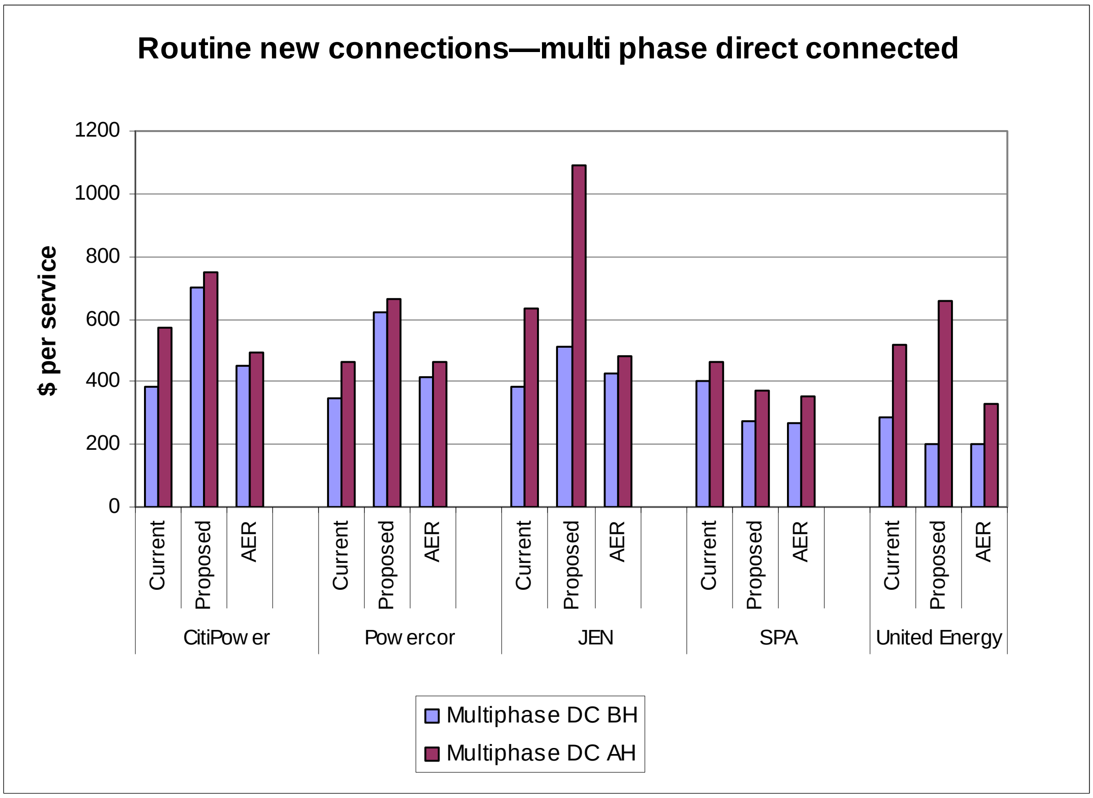
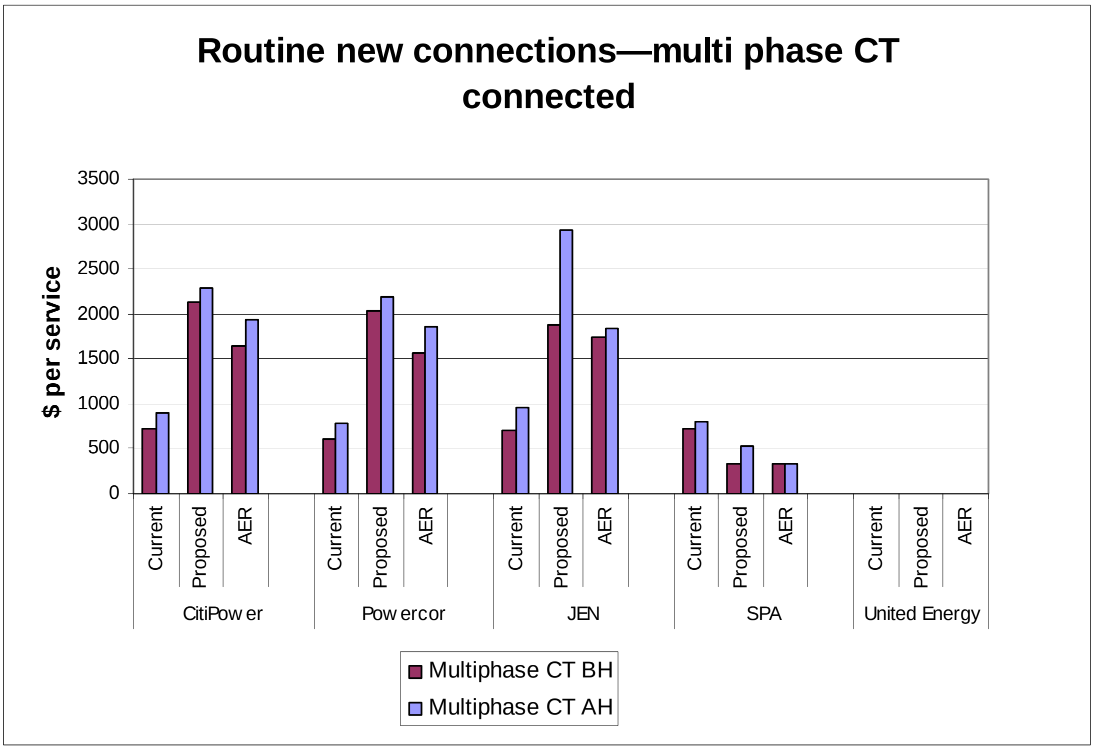


Figure 20.11 AER analysis—Routine new connections multi phase CT connected—BH and AH ($, 2010)



Note: United Energy did not provide any prices for routine new connections—multi phase CT connected.

While CitiPower, Powercor and Jemena provided a build up of all services, SP AusNet carried out a top down analysis based on revenues and service volume forecasts. United Energy's proposed prices were largely based on prices proposed by its winning bidder contractor.

In general, analysis of the proposed prices revealed that a build up of costs has resulted in higher proposed prices, while a competitive tender process has resulted in the majority of United Energy's fee based alternative control services prices being significantly lower than the other Victorian DNSPs' prices. SP AusNet's proposed prices were mostly in a range between the built up prices and United Energy's proposed prices.

The AER determined prices, where different to those proposed by the Victorian DNSPs, have been calculated by the AER having regard to its decisions on cost inputs in this chapter. The AER's analysis of the Victorian DNSPs' methodologies has resulted in some decreases to each DNSP's prices, while the application of Impaq's advice to CitiPower's, Powercor's and Jemena's prices has also resulted in large price decreases. In several cases, the resulting prices for CitiPower, Powercor and Jemena are still higher than that proposed by United Energy and SP AusNet, however in some cases the resulting prices for CitiPower, Powercor and Jemena are lower than those proposed by United Energy and SP AusNet. Due to the differing basis for price calculation, and considering that some of the services may not be delivered in the same manner or include the exact same elements, the AER has determined prices on a case by case basis.

In the absence of further information on the differing nature of the fee based services, or actual cost build ups for SP AusNet's and United Energy's fee based alternative control services, the AER considers its approach to determining prices for this draft decision to be reasonable. The following sections summarise the AER's draft decisions for each DNSP.

CitiPower and Powercor

The AER rejects CitiPower's and Powercor's proposed fee based alternative control service prices for 2011, including the proposed prices for routine new connections submitted during the review process.

The AER has made the following adjustments to CitiPower's and Powercor's proposed prices for 2011:

- applied the high point of business and after hours line worker hourly charge out rates recommended by Impaq, after reducing the rate to account for a 3 per cent profit margin
- where the proposed times were found to be above the reasonable range determined by Impaq, applied the high point of the recommended times taken to perform alternative control services
- applied labour and materials escalators as outlined in appendix K
- removed the additional profit margin applied by CitiPower and Powercor.

The AER has not approved prices for the following services for CitiPower and Powercor:

- Audit design—CitiPower and Powercor proposed this service as standard control. The AER has classified this service as alternative control fee based and therefore requires CitiPower and Powercor to propose a fee for this service.
- Reserve feeder—CitiPower and Powercor proposed this service to be a negotiated service. The AER has classified this service as an alternative control fee based service and therefore requires CitiPower and Powercor to propose a fee for this service.
- Re-test of type 5 and 6 meters—CitiPower and Powercor proposed this service to be an unregulated service. The AER has classified this service as an alternative control fee based service and therefore requires CitiPower and Powercor to propose a fee for this service.
- Fault level compliance—CitiPower proposed this service as a standard control service. In this draft decision, the AER has classified fault level compliance as a fee based alternative control service. The AER requests that CitiPower provide further information to support its proposed kWh fee as an alternative control service fee as part of its revised regulatory proposal.

The AER's draft determination on CitiPower's and Powercor's fee based alternative control services prices for 2011 is set out in appendix O.

The AER does not approve the significant escalation of service provider contract rates within CitiPower's and Powercor's alternative control services prices over 2012–15. The AER requires CitiPower and Powercor to submit price paths consistent with the control mechanism set out in the Framework and approach paper for their fee based alternative control services as part of their revised regulatory proposals. The AER considers that CitiPower's and Powercor's price paths should incorporate the labour and materials escalators the AER has approved for standard control services, set out in appendix K.

Jemena

The AER rejects Jemena's proposed fee based alternative control service prices for 2011, including prices for routine new connections submitted during the review.

The AER has made the following adjustments to Jemena's proposed fee based alternative control service prices for 2011:

- applied the high point of business and after hours line worker hourly charge out rates recommended by Impaq, after reducing the rate to account for a 3 per cent profit margin
- for Jemena's scheduling team rates, applied the midpoint between Impaq's recommended back office rate and line worker rate where appropriate
- where the proposed times were found to be above the reasonable range determined by Impaq, applied the high point of the times taken to perform alternative control services
- in equating the approved prices to 2011 dollars (from 2008 dollars as submitted by Jemena), the AER has applied the same labour and materials escalators it applied to standard control services in this draft decision, as set out in appendix K.

The AER also rejects Jemena's proposed prices for meter equipment tests, as it considers the Formway contract rate included within the build up of the proposed prices has not been appropriately justified. The AER requests further information from Jemena on the costs of providing meter equipment test services.

The AER requests that Jemena submit proposed prices for new connections services where Jemena is not the responsible person for metering, for application in 2014 and 2015, as discussed in section 20.7.1.

The AER has not approved prices for Jemena's proposed remote metering services, as these services are to be regulated as excluded services, as discussed in section 20.4.1.

The AER's draft determination on Jemena's fee based alternative control services prices for 2011 is set out in appendix O.

The AER requests that Jemena input the labour and materials escalators the AER has approved for standard control services (set out in appendix K) in calculating the X factors for its form of control, as part of its revised regulatory proposal.

SP AusNet

The AER rejects SP AusNet's proposed fee based alternative control service prices for 2011.

In summary, the AER has made the following adjustment to SP AusNet's proposed prices:

- applied labour escalators as set out in appendix K to SP AusNet's price models for field officer visits, new connections and service vehicle visits to determine an adjusted price.

The AER has not approved a price for after hours service truck visits, and requests further information from SP AusNet on the costs of providing this service as part of its revised regulatory proposal such that a cost build up using Impaq's recommended labour charge out rates and times can be undertaken.

The AER requests that SP AusNet submit proposed prices for new connections services where SP AusNet is not the responsible person for metering, for application in 2014 and 2015, as discussed above.

The AER's draft determination on SP AusNet's fee based alternative control services prices is set out in appendix O.

The AER accepts SP AusNet's proposed form of control for its fee based alternative control services.

United Energy

The AER rejects United Energy's proposed fee based alternative control service prices for 2011 for the following services:

- temporary cover of LV mains—two wire cover—AH
- temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—BH
- temporary supplies (exc. inspection)—coincident disconnection—multiphase to 100A—AH
- temporary supplies (exc. inspection)—independent disconnection—multiphase to 100A—BH
- new connections where United Energy is responsible—single phase single element—AH
- new connections where United Energy is responsible—single phase two element (off peak)—AH

- new connections where United Energy is responsible—three phase direct connected—AH
- new connections where United Energy is responsible—single phase single element—AH
- new connections where United Energy is responsible—single phase two element (off peak)—AH
- new connections where United Energy is responsible—three phase direct connected—AH
- service vehicle visits (without inspection)—first 30 minutes—AH.

The AER has not approved prices for the following fee based services as no fee was provided for these services:

- routine new connections - three phase current transformer connected—BH
- routine new connections - three phase current transformer connected—AH[138]

The AER has not approved United Energy's proposed charges for the provision of possum guards, security lighting installation or meter provision for first tier customers consuming more than 160 kWh per annum, as it considers these services are contestable. The AER has also not approved United Energy's proposed charges for meter data services, as cost recovery for meter data services was provided as part of the AER's AMI determination in October 2009.

The AER's draft determination on United Energy's fee based alternative control services prices is set out in appendix O. The AER's decision on these services is also set out in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy.

The AER accepts United Energy's proposed form of control for its fee based alternative control services.

20.8.2 Quoted services

For all Victorian DNSPs, the AER's draft decision is that materials costs incurred in the provision of quoted services will be recovered from customers at cost, without overhead or margin. The AER's decision on these services is also set out in the distribution determination documents for CitiPower, Powercor, Jemena, SP AusNet and United Energy

CitiPower and Powercor

The AER does not approve CitiPower's and Powercor's proposed quoted services labour rate for 2011. The AER's approved labour rate is based on Impaq's advice on the reasonable range of distribution line worker rates, and is set out in appendix O.

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138 United Energy, *Regulatory proposal Appendix C-2,* p. 32.

The AER's draft decision on the form of control for CitiPower and Powercor's quoted services labour rates is to apply an escalation of the approved 2011 quoted services labour rate by the outsourced labour escalation rate it approved for standard control services, set out in table 20.7, and discussed in appendix K.

Jemena

The AER does not approve Jemena's proposed quoted services labour rate for 2011. The AER's approved labour rate is based on Impaq's advice on the reasonable range of distribution line worker rates, and is set out in appendix O.

The AER's draft decision on the form of control for Jemena's quoted services labour rates is to apply an escalation of the approved 2011 quoted services labour rate by the outsourced labour escalation rate it approved for standard control services, discussed in appendix K.

SP AusNet

The AER approves SP AusNet's proposed 2011 labour rate for quoted services.

The AER's draft decision on the form of control for SP AusNet's quoted services labour rates is to apply an escalation of the approved 2011 quoted services labour rate by the outsourced labour escalation rate it approved for standard control services, discussed in appendix K.

United Energy

In the absence of any proposed quoted services input rates or price path, the AER's draft decision is to not approve a form of control for quoted services to apply to United Energy. The AER requests that United Energy submit appropriate information in its revised regulatory proposal including the hourly labour rate for quoted services.

The AER considers the appropriate form of control is one consistent with its determination for the other Victorian DNSPs in this draft decision. That is the form of control for quoted services labour rates is to apply an escalation of the approved 2011 quoted services labour rate by the outsourced labour escalation rate approved by the AER for standard control services discussed in appendix K.

21 Outcomes monitoring and compliance

21.1 Introduction

This chapter sets out the monitoring framework that the AER intends to establish to monitor the consistency of the Victorian DNSPs with the AER's 2011–15 Victorian distribution determinations, and the service levels delivered to customers.

In addition to this outcomes monitoring framework, the chapter also sets out the information the AER proposes to collect annually to assess the Victorian DNSPs' compliance with the distribution determination such as information on incentive schemes and approved control mechanisms that are applicable to the DNSP.

It is proposed that the monitoring framework set out in this chapter will replace the existing annual reporting framework previously established by the Essential Services Commission of Victoria (ESCV) for monitoring a DNSP's regulatory accounts and network performance indicators. This monitoring framework also includes monitoring outcomes of the capex and opex programs proposed by the DNSP. This means that in addition to the reporting of actual opex and capex, and volume information by DNSPs (as is currently required under the Victorian framework), the AER will also monitor certain outcome measures for material programs and cost categories. The outcome measures will include measures of the effectiveness of opex and capex expenditure through a number of monitoring and performance measures as well as physical volumes of assets such as the number of new connections. The outcomes monitoring framework also includes outcome measures relating to service standard levels, such as the monitoring of low reliability feeders for Victorian DNSPs, which continues the existing ESCV approach.

The information outlined in this chapter will be collected annually through the issuing of a regulatory information notice (RIN) under section 28F(1)(a) of the National Electricity Law (NEL) following the final Victorian distribution determinations. The outcomes monitoring measures proposed in this chapter are intended to provide guidance on the framework that the AER intends to implement. The AER will undertake further consultation with Victorian DNSPs and other stakeholders to determine the specific form of the outcome measures for Victorian DNSPs to report against as part of a separate RIN process.

21.2 Purpose

21.2.1 Monitor consistency with the AER distribution determinations

The annual outcome monitoring measures discussed in this chapter will assist the AER in monitoring the consistency of Victorian DNSPs with their distribution determination. The AER will monitor both expenditure outcomes and the level of performance delivered to customers by DNSPs including service standard levels, and other outcomes such as the effectiveness of operational and maintenance activities and capital investment.

The AER recognises that the regulatory framework provides DNSPs with an ex ante allowance. DNSPs are not required to spend all the allowed capital, and operating and maintenance expenditures, nor are they required to spend it in a manner consistent with the distribution determination. However, the AER considers that there is considerable benefit in monitoring the level of actual expenditure, and the outcomes achieved by the Victorian DNSPs, against the approved allowances in the AER's distribution determinations. The monitoring framework will better inform the AER in its assessments at the next Victorian distribution determinations, and improve the accountability of Victorian DNSPs.

The annual outcome monitoring measures will also contribute to the achievement of the national electricity objective, by providing the AER with the information necessary to carry out its regulatory functions and assessments under the National Electricity Rules (NER) and NEL.

21.2.2 Transparency and accountability

The annual outcomes monitoring framework will increase the transparency and accountability of Victorian DNSPs in respect to the AER's 2011–15 Victorian distribution determinations, and the delivery of services to customers. A key area that is to be monitored is how the outcomes achieved by DNSPs compare against the forecasts accepted or determined by the AER in its distribution determinations. The outcomes monitoring framework will also assist the AER in understanding past performance and potentially allow the AER to distinguish between those DNSPs that have found more innovative and efficient techniques to reduce expenditure, and those that have deferred expenditure to the detriment of long term network performance.

The annual outcomes monitoring measures will promote transparency in the DNSPs' investment and expenditure decisions. This assists in achieving the national electricity objective in the NEL. Information on the price, quality, reliability and security of supply of electricity is required for the AER to undertake accurate assessments.

21.2.3 Annual compliance reporting

This chapter also sets out the information reporting requirements that the AER requires to undertake its other regulatory functions in relation to its 2011–15 Victorian distribution determinations. These information reporting requirements relate to the incentive schemes and approved control mechanisms which form part of the AER's distribution determinations for the Victorian DNSPs.

21.3 Regulatory framework

The AER is responsible for the economic regulation of DNSPs in the national electricity market (NEM). Section 16 of the NEL states that the AER must exercise its economic regulatory functions and powers in a manner that will or is likely to contribute to the achievement of the national electricity objective, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity

- the reliability, safety and security of the national electricity system.[1]

Clause 6.1.1 of the NER, states that the AER is responsible for the economic regulation of distribution services by means of, or in connection with, distribution systems that form part of the national grid.

Section 28F(1)(a) of the NEL allows the AER to serve a RIN on a DNSP if the AER considers it reasonably necessary for the performance or exercise of a function or power conferred on it under the NEL or the NER.

21.4 Existing reporting requirements of DNSPs under distribution licences

Victorian DNSPs are currently required to report the following information to the AER under the existing regulatory framework of the ESCV:

- network performance indicators and network asset statistics under the *Information Specification (service performance) for Victorian electricity distributors*

- comprehensive regulatory account statements under *Electricity Industry Guideline No. 3: Regulatory Information Requirements*.

The AER considers that much of the existing reporting framework is relevant for the ongoing monitoring of a DNSP's service and financial performance, and intends to incorporate a significant amount of the information currently gathered under these requirements within the AER's new outcomes monitoring framework.

21.5 Collection and publication of information requirements

The information required for the outcomes monitoring measures and assessment of the DNSP's compliance with its distribution determination will be collected annually through the issuing of a RIN under section 28F(1)(a) of the NEL. The AER expects that the information required to implement this outcomes monitoring framework will be consistent with the information the AER relied on in making its Victorian distribution determinations. The AER also intends to publish relevant information collected through the outcomes monitoring process.[2]

21.6 Summary of submissions

The AER received three submissions regarding the monitoring of aspects of service standards performance pursuant to the Victorian DNSPs' 2011–15 regulatory proposals.

The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria (the Minister), submitted that the AER should review the form and content of comparative performance reports for DNSPs. The Minister also requested that the AER review

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1 NEL, section 7.
2 For information regarding the AER’s use and disclosure of information provided to it, see the ACCC/AER Information Policy, October 2008, available at http://www.aer.gov.au.

service standard measures such as the target level of reliability for the worst served 15 per cent of customers, and the thresholds for reporting low reliability feeders.[3]

The Energy Users Coalition of Victoria (EUCV) submitted that the AER should continue the ESCV's assessment of the worst performing feeders with the goal of bringing all feeders to the same level.[4]

The Victorian Council of Social Services (VCOSS) noted that the AER should provide a supplementary report to its draft decision which should include information on service performance by geographical area.[5]

21.7 Outcomes monitoring measures

This section specifies the outcome monitoring measures that the AER intends to establish for monitoring the Victorian DNSPs' consistency with their 2011–15 distribution determinations.

These outcome monitoring measures are intended to provide guidance on the monitoring framework that the AER intends to implement. The final form of the outcome monitoring measures and the specific information required to develop them will be subject to further consultation with the Victorian DNSPs as part of a separate RIN process following the final Victorian distribution determinations.

21.7.1 Capital expenditure

Financial reporting (actual capex spend)

The AER will monitor the capex activities of Victorian DNSPs to allow comparison of the capex forecasts of DNSPs as approved by the AER in its distribution determination, with actual expenditure in the regulatory control period.

It is proposed that the Victorian DNSPs will be asked to report annually:

- actual capex activities according to the building blocks, further separated into different network types (or other suitable sub-categories), similar to those currently provided under the AER's RINs for the Victorian distribution determinations

- changes to the regulatory asset base (RAB), including depreciation, write-downs and disposals.

Reinforcement (augmentation)

The AER will collect information on the level of capacity utilisation for each zone substation, for each distribution feeder and distribution transformers (in aggregate).

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3 The Hon. Peter Batchelor MP, Minister for Energy and Resources, Victoria, *Submission on the Victorian electricity distribution network service providers' regulatory proposals for 2011–2015*, February 2010, pp. 6-7.

4 Energy Users Coalition of Victoria, *Victorian electricity distribution revenue reset*, February 2010, p. 65.

5 Victorian Council of Social Services, *Victorian electricity distribution network service providers' regulatory proposals*, 16 February 2010, p. 2.

This will enable a calculation of load indexes which will reveal the average utilisation of key elements of each DNSP's network. These outcome measures will be tracked over time, and will allow the AER to monitor the effectiveness of the Victorian DNSPs' reinforcement (augmentation) investment decisions over the regulatory control period. These outcome measures will also further inform the AER of the investment patterns of the Victorian DNSPs for the purposes of its future Victorian distribution determination, and promote transparency and accountability in the DNSPs' investment and expenditure decisions.

Individual zone substations

It is proposed that for each zone substation, the AER will ask Victorian DNSPs to report annually:

- actual zone substation max demand (weather corrected)
- N and N-1 Capacity (where applicable)
- current MW capacity shortfall and Energy (MWh) at risk calculated in a manner consistent with the DNSP's calculation of load at risk for the economic assessment of investment decisions.

Victorian DNSPs will also be asked to provide annual forecasts for a period of five years for:

- forecast zone substation max demand (weather corrected)
- forecast N and N-1 capacity as a result of the forecast level of reinforcement investment
- capacity forecast (MW) and Energy (MWh) at risk with the forecast level of investment.

Individual distribution feeders

It is proposed that for each distribution feeder, the Victorian DNSPs will be asked to report annually:

- design capacity of the feeder (at the zone substation)
- actual peak demand on each distribution feeder.

Victorian DNSPs will also be asked to provide an annual forecast for a period of five years of:

- forecast feeder capacity as a result of the forecast investment
- forecast peak demand on each distribution feeder.

Distribution transformers

It is proposed that the Victorian DNSPs will be asked to report in aggregate terms,[6] the following information annually:

- total distribution transformer capacity
- actual total peak demand
- aggregate utilisation.

Victorian DNSPs will also be asked to provide an annual forecast for a period of five years of:

- forecast transformer capacity as a result of the forecast investment
- forecast total peak demand
- forecast aggregate utilisation.

Much of the information required for these outcomes measures is currently reported to the AER by Victorian DNSPs under the *Information Specification (service performance) for Victorian electricity distributors* as part of the existing ESCV framework, or published in the DNSP's distribution planning report. DNSPs were also required to report against some of these factors under the AER's RINs for its Victorian distribution determinations, or the information was subsequently requested by the AER's consultant. As such, the AER considers that the Victorian DNSPs have the reporting mechanisms available to provide this information to the AER on an annual basis and that the provision of this information should not represent an undue regulatory burden.

Asset replacement (reliability and quality maintained)

The AER intends to capture information reflecting the health (or condition) of each zone substation transformer and major item of switchgear, and track the changes in health (or condition) over time. This outcome monitoring measure can be used to inform the AER of the effectiveness of the DNSPs' asset replacement investment decisions over the regulatory control period. The exact assets that will be covered by this monitoring measure will be determined through consultation which each Victorian DNSP through the separate RIN process following the final Victorian distribution determinations.

It is proposed that for each zone substation transformer and major item of switchgear (for example circuit breakers), the Victorian DNSPs will be asked to report annually:

- a health or condition ranking for each zone substation transformer and major item of switchgear on a consistent scale of 1–5[7] based on the DNSP's internal approach to assigning and monitoring asset conditions

6 Such as in bands of utilisation levels (heavy, medium and light loading conditions).

- a forecast of the condition or health of the same assets using a consistent scale reflecting the forecast condition derogation of the assets (that is, what would happen if no asset replacement investment was undertaken)

- a forecast of the condition or health of the same assets using a consistent scale reflecting the forecast condition derogation of the assets, but taking account of the impact of the forecast level of asset replacement investment

- for each asset category the forecast volume of replacement and refurbishment to be undertaken during the next price control.

Some of these reporting requirements were the subject of supplementary information requests by the AER as part of its Victorian distribution determinations. The AER considers that DNSPs should be able to provide this information to the AER on an annual basis as DNSPs have previously reported against some of these factors, and effective network asset managers should already have this information available. The AER will consult on the exact list of sub-transformers, and major items of switchgear to be included in the outcomes monitoring measure through a separate RIN process following the final Victorian distribution determinations.

Customer connections

The customer connection outcome measure will monitor the volume of customer connections, the average cost and average level of customer contributions per connection relative to the Victorian DNSP’s forecasts approved by the AER in its Victorian distribution determinations. This outcome measure will allow comparisons by the AER of key customer connection metrics against the forecasts by DNSPs approved by the AER in its distribution determinations.

Under this outcome measure, the DNSP will be asked to specify the number and cost (both net and gross) of customer connections by connection type (consistent with the categories submitted to the AER in the DNSP's regulatory proposal).

The Victorian DNSPs have reported the information required for this outcome measure in supplementary information requests by the AER and in the AER's RINs as part of the Victorian distribution determinations.

Expenditure programs to reduce bushfire risk

As noted in section 8.6.3 of this draft determination, both SP AusNet and Powercor have substantial exposure to high bushfire risk zones. While the Victorian Bushfire Royal Commission (VBRC) has not yet published its final recommendations to the Victorian Government, both the AER and the Victorian DNSPs note that the VBRC is expected to make recommendations for increased activities to reduce future bushfire risks. Hence, the AER has provided an interim allowance of capital expenditure for the Victorian DNSPs to mitigate bushfire risk.

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[7] A ranking of 1 means the asset is new or as new, and 5 means the asset is at the end of its serviceable life.

The AER considers that, in order to effectively monitor such expenditure, the actual expenditures of SP AusNet and Powecor in this area should be ring-fenced from the traditional reliability and quality maintained category. SP AusNet and Powercor will be required to annually report their action plans, actual activities against such plans, and actual expenditure to the AER.

21.7.2 Operating expenditure

Actual operating and maintenance activities

The AER will monitor the operating and maintenance activities of Victorian DNSPs to allow comparison of the Victorian DNSPs' opex forecasts approved by the AER in its distribution determinations, with actual expenditure in the regulatory control period.

It is proposed that the Victorian DNSPs will be asked to report annually:

- actual opex activities according to the building blocks, further separated into different network types (or other suitable sub-categories), similar to those currently reported under the AER's RIN for the Victorian distribution determinations
- regulated revenue
- transmission use of system payment
- avoided payment.

Failure rates

Failure rates are reflective of a DNSP's asset management outcome, which is a combination of asset replacement expenditure and the effectiveness of their operation and maintenance activities. The monitoring of failure rates will allow the AER to gain a further indication of the impact of the DNSP's investment decisions. This outcome measure will provide greater transparency and accountability of the performance of a DNSP and will better inform the AER in its assessments of the DNSPs regulatory proposal in the 2016–20 Victorian distribution determinations.

Victorian DNSPs should forecast an annual failure rate for each asset category and against each failure category, taking into account planned investment over the period. Annual out-turn failure rates will be reported by Victorian DNSPs during the regulatory control period on a normalised (per unit) basis. The precise measures that will be covered by this monitoring measure will be determined through consultation with each Victorian DNSP after the final distribution determinations through a RIN process.

Victorian DNSPs are currently reporting the number of each type of failure to the AER. The AER considers that Victorian DNSPs have the reporting mechanisms available to provide the information for this outcome measure to the AER as DNSPs have previously reported this information in the AER's RINs for the Victorian distribution determinations.

Efficiency gain through smart meter technology

It is expected that the Advanced Metering Infrastructure (AMI) rollout program will enable DNSPs to improve their operational efficiency, for example faster response time and more accurate response through better network intelligence. The AER intends to develop a framework to effectively monitor DNSP's costs and how they are being impacted by the use of AMI technologies in the forthcoming regulatory control period as part of the RIN process.

21.7.3 Service standards reporting requirements

In addition to the S factor reporting requirements under the AER's service target performance incentive scheme (STPIS) as set out under section 21.8.1 of this chapter, the AER will request Victorian DNSPs to report against the following service standard measures.

Reliability and quality of supply measures

This includes network average measures and feeder performance measures similar to those currently reported under the *Information Specification (service performance) for Victorian DNSPs* under the existing ESCV framework.

Customer services measures

This includes guaranteed service level (GSL) payments, call centre performance and customer complaints measures similar to those currently reported under the *Information Specification (service performance) for Victorian DNSPs* under the existing ESCV framework.

Worst served customers

It is proposed that the Victorian DNSPs will be asked to report annually:

- the duration of interruptions (planned and unplanned) experienced by the 15 per cent of customers in an area that experience the longest time off supply in that year
- low reliability feeders for which the average minutes off supply (for planned and unplanned interruptions) is above a threshold.

The information required for this outcome measure is currently collected under the ESCV's Victorian reporting framework, and the AER intends to maintain this reporting arrangement in the forthcoming regulatory control period.

The AER considers that a prudent DNSP should exercise its best endeavours to effectively allocate its capex and opex expenditures to manage its assets, and to meet the reasonable customer expectations of reliability of supply, as required by the *Electricity Distribution Code* (EDC).[8] As such, the AER considers that monitoring network average performance alone is insufficient to measure a DNSP's asset management practice. As the STPIS measures performance against average service levels, it is also necessary to monitor performance levels to the worst served

[8] ESCV, *Electricity Distribution Code*, February 2010.

customers. The AER considers such reporting requirements necessary in order to monitor the performance of the distribution network and for the future application of the STPIS.

These outcome monitoring measures have regard to the Minister's submission to the AER that it review service standard measures such as the target level of reliability for the worst served 15 per cent of customers, and the thresholds for reporting low reliability feeders.[9]

Network performance during major event days

Major event days are currently not subject to a financial incentive scheme. The AER intends to develop monitoring measures for major event days in the future, and will consult further with DNSPs on this issue. The precise measures that will be covered by this monitoring measure will be determined through consultation with each Victorian DNSP after the final distribution determination through a RIN process.

The AER considers it necessary to monitor a DNSP's performance during these days to provide the AER with further information on the adequacy of a DNSP's emergency management system. This is consistent with the monitoring of services to the worst served customers, and will compliment the network average measures reported under the STPIS.

21.7.4 Network statistics

The network statistics outcome measure intends to monitor the quantities of major asset types. The AER considers this measure to be necessary as quantities of major asset types form part of the key outcomes measures of a DNSP and should be monitored continuously.

The Victorian DNSPs currently report the information required for this outcome measure under the current ESCV arrangements, and should be able to provide this information to the AER on annual basis.

21.8 Compliance with distribution determination

The section provides a summary of the annual compliance reporting requirements of Victorian DNSPs for the models and schemes that apply to the Victorian DNSPs under the distribution determinations.

21.8.1 Service target performance incentive scheme

The Victorian DNSPs must report on their annual performance against the S factor parameters applicable to them under the AER's STPIS as set out in the relevant distribution determination in accordance with any applicable RIN.

Among other things, the Victorian DNSPs will be asked to provide details annually of each of the exclusions under clauses 3.3 and 5.4 of the STPIS that the DNSP has applied in calculating the revenue increment or decrement under the scheme

[9] The Minister, *Submission to the AER*, February 2010, pp. 6-7.

21.8.2 Efficiency benefit sharing scheme

Under the efficiency benefit sharing scheme (EBSS) the following opex cost categories will be excluded from the operation of the EBSS for the forthcoming regulatory control period, and Victorian DNSPs will be asked to report these costs:

- debt raising costs
- self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the demand management innovation allowance
- GSL payments.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS, which include non-network alternatives and recognised pass through events.

21.8.3 Demand management incentive scheme

Under the demand management incentive scheme (DMIS) the Victorian DNSPs must submit to the AER an annual report on their expenditure under the demand management incentive allowance (DMIA) for each regulatory year of the regulatory control period.

The AER will ask Victorian DNSPs to report annually:

- DMIA expenditure for each year of the forthcoming regulatory control period. The details of the annual reporting requirements are set out under section 3.14 of the DMIS
- calculations and explanations of foregone revenues for each year of the forthcoming regulatory control period. Details of annual reporting requirements are set out in section 3.24 of the DMIS.

21.8.4 Pass throughs

The AER will ask Victorian DNSPs to list and describe any pass through events during the reporting year in accordance with clause 6.6.1 of the NER.

This will allow the AER to confirm whether or not a positive or negative pass through event has occurred during the reporting period.

21.8.5 Control mechanisms for standard control services and alternative control services

Appendix G—Distribution tariffs of this draft decision sets out how the Victorian DNSPs are to demonstrate, as part of their annual pricing proposal, compliance with the weighted average price cap formula (WAPC) in the forthcoming regulatory control period in accordance with clause 6.12.1(13) of the NER.

Chapters 19 and 20 of this draft decision set out how the Victorian DNSPs are to demonstrate, as part of their annual pricing proposal, compliance with the price cap form of control for alternative control services (public lighting and other alternative control services) in the forthcoming 2011–15 regulatory control period in accordance with clause 6.12.1(13) of the NER.

Appendix F—Transmission tariffs sets out how each Victorian DNSP is to report its recovery of transmission use of system charges for each regulatory year of the forthcoming regulatory control period, including adjustments for the over or under recovery of those charges in accordance with clause 6.12.1(19) of the NER.

The specific information the AER requires from the Victorian DNSPs to assess their compliance with the WAPC formula, and to assess their recovery of transmission use of system charges in the forthcoming regulatory control period is intended to be collected in a RIN.

As stated in chapter 4.6.3, the AER will not require annual information regarding compliance with the electricity ring fencing guidelines. The AER will instead continue with the ESCV's approach to monitoring the electricity ring fencing guidelines, including investigating complaints and conducting periodic audits.

21.8.6 Annual inflation adjustment

The AER will ask Victorian DNSPs to report the percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities from March in regulatory year t – 2 to March in regulatory year t – 1.

The AER considers that the Victorian DNSPs should report this information as it will allow the AER to make adjustments to the WAPC each year.

21.8.7 Actual demand quantities

The AER will ask Victorian DNSPs to report customer numbers, energy consumption, and the maximum demand details broken down by tariff class.

This information will assist the AER's calculation of the WAPC each year.

21.8.8 Licence fees

The AER will ask Victorian DNSPs to report their calculation of the licence fee factor as required for calculation of the WAPC as set out in appendix G of this distribution determination.

21.8.9 Public lighting

Consistent with the AER's *Energy Efficient Public Lighting Charges* 2009 final decision and this draft decision, DNSPs will be required to report actual capex expenditure between energy efficient luminaires and existing luminaires. This will ensure that only those councils choosing to install energy efficient public lighting in their municipalities will pay for that service. Cross-subsidisation of operation, maintenance and replacement (OMR) charges will be minimised through these requirements.

21.8.10 Summary of the proposed monitoring measures

Table 21.1 provides a summary of the AER's proposed outcomes monitoring measures for Victorian DNSPs. The table also shows the purpose of each outcome measure, and the extent to which the outcome measure is currently reported by Victorian DNSPs (where appropriate).

Table 21.1 Summary of outcomes monitoring and compliance measures

Monitoring or compliance measure	Purposes of information collection	Current reporting of information
Capital expenditure Financial reporting (actual capex spend) Reinforcement (augmentation) -*individual zone substations* -*individual distribution feeders* -*distribution transformers* Asset replacement (reliability and quality maintained) Customer Connections Expenditure programs to reduce bushfire risk	Provides for comparison between capex forecasts of Victorian DNSPs as approved by the AER in its distribution determinations, with actual expenditure in the regulatory control period. Better inform the AER in its assessment of the Victorian DNSPs in the next Victorian distribution determinations. Promote transparency and accountability in the Victorian DNSPs' investment and expenditure decisions, and the delivery of services to customers. Monitoring of the allowance given by the AER to SP AusNet and Powercor to mitigate bushfire risk.	Much of the information required for these outcomes measures is currently reported by Victorian DNSPs under the existing ESCV framework and in distribution planning reports. The Victorian DNSPs have also provided some of the information for these outcome measures in RINs issued by the AER. As the allowance to mitigate bushfire risk is a new allowance, SP AusNet and Powercor have not previously reported this information to the AER.
Operating expenditure Actual operating and maintenance activities Failure rates	Provides for comparison of opex forecasts of Victorian DNSPs as approved by the AER in its distribution determinations, with actual expenditure in the regulatory control period. Inform the AER of the impact of the Victorian DNSPs' asset replacement and operation and maintenance activities. Better inform the AER in its assessment of the Victorian DNSPs in the next Victorian distribution determinations. Promote transparency and accountability in the Victorian DNSPs' investment and expenditure decisions, and the delivery of services to customers.	Much of the information required for this outcome measure has been previously reported by DNSPs in the AER's RINs for the Victorian distribution determinations.

Service standards reporting requirements *Reliability and quality of supply measure* *Customer services measure* *Worst served customers* *Network performance during major event days*	Monitoring the performance of the distribution network for the future application of the AER's STPIS.	Information currently reported under the existing Victorian reporting framework, and collected by the ESCV.
Network statistics	Inform the AER in its assessment of the Victorian DNSPs in the next Victorian distribution determinations. Promote transparency and accountability in the DNSPs' investment and expenditure decisions, and the delivery of services to customers.	Information currently reported under the existing Victorian reporting framework and collected by the ESCV.
Service target performance incentive scheme	Ensure compliance with the AER's STPIS.	Reporting requirements are specified under the AER's STPIS.
Efficiency benefit sharing scheme	Ensure compliance with the AER's EBSS.	Information required to be reported to the AER is specified in the AER's EBSS.
Demand management incentive scheme	Assessment of expenditure and compliance with the DMIA criteria, and approval of expenditures. Assessment of revenues foregone as a result of implementation of demand management projects approved under the DMIA, and approval of compensation.	Reporting requirements are specified in the AER's DMIS.
Pass throughs	Confirm whether or not a positive or negative pass through event has occurred during the reporting period (a regulatory year).	Victorian DNSPs report on pass through events under clause 6.6.1 of the NER.
Control mechanisms for standard control services and alternative control services	Monitoring the Victorian DNSPs' compliance with the control mechanisms as set out in clause 6.12.1(13) of the NER.	Victorian DNSPs currently report information to the AER in their pricing proposals. The information is currently reported as set out in the ESCV's Electricity distribution price review (EDPR) 2006–10.[10]

[10] ESCV, EDPR 2006–10, vol. 2, October 2006.

Annual inflation adjustment	Adjustment to the WAPC each year.	Victorian DNSPs currently report the information required for this measure to the AER.
Actual demand quantities	Calculation of the WAPC each year.	Victorian DNSPs currently report the information required for this measure to the AER.
Licence fees	Calculation of the WAPC each year.	Victorian DNSPs currently report the information required for this measure to the AER.
Public lighting	Ensure that only those councils choosing to install energy efficient public lighting in their municipalities will pay for that service.	Information currently required to be reported under the AER's *Energy Efficient Public Lighting Charges* 2009 decision.

Glossary

ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
AECOM	Architecture Engineering Consulting Operations and Management
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AH	After hours
Ai Group	Australian Industry Group
AMA	Asset management agreement
AMI	Advanced metering infrastructure
ANSIO	Australian National State and Industry Outlook
ANZSIC	Australian and New Zealand Standard Industrial Classification 2006
AOFM	Australian Office of Financial Management
APR	Annual planning report (VENCorp)
ASIC	Australian Securities and Investments Commission
ASX	Australian Securities Exchange
ATO	Australian Taxation Office
AUD	Australian dollar
AWOTE	average weekly ordinary time earnings
BFV	Bloomberg fair value
BGN	Bloomberg generic yield
BH	Business hours
CALC	Consumer Action Law Centre
capex	capital expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CFA	Country Fire Authority

CFC	Construction Forecasting Council
CFL	compact fluorescent light
CGS	Commonwealth Government Security
Citelum	Citelum Australia Pty Ltd
CMEN	common multiple earthed neutral
COWP	Capital and Operational Work Plan
CPI	consumer price index
CPP	Critical peak pricing
CPRS	carbon pollution reduction scheme
CS	Customer Service
CT connected	Current transformer connected
CT/VT	current/voltage transformer
CUAC	Consumer Utilities Advocacy Centre
current regulatory control period	1 January 2006 to 31 December 2010
Darebin	Darebin City Council
DC	Direct connected
DEHWA	Department of Heritage, Water and the Arts
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DNOs	Distribution Network Operators
DNSP	distribution network service provider
DP	degree of polymerisation
DPI	Department of Primary Industries
draft decision	AER, Draft decision, Victorian draft distribution determination 2011 to 2015.
draft distribution determinations	AER, Victorian draft distribution determination, 2011 to 2015.
DRP	Debt risk premium
DUOS	Distribution use of system
EBA	enterprise bargaining agreement

EBSS	Efficiency benefit sharing scheme
ECM	Efficiency carryover mechanism
EDC	Electricity Distribution Code
EDPR	Electricity Distribution Price Review
EGW	electricity, gas and water
ELV	Electric vehicle
EPA	Environment Protection Authority Victoria
ESCOSA	Essential Services Commission of South Australia
ESCV	Essential Services Commission of Victoria
ESMS	electricity safety management scheme
ESV	Energy Safe Victoria
ETS	emissions trading scheme
ETSA	Electricity Trust of South Australia
EUAA	Energy Users Association of Australia
EUCV	Energy Users Coalition of Victoria
EWOV	Energy and Water Ombudsman (Victoria)
FIG	Financial Investor Group
Forthcoming regulatory control period	1 January 2011 to 31 December 2015
GDP	gross domestic product
GFC	Global financial crisis
GIS	Geographical Information System
GRP	Gross regional product
GSL	Guaranteed service level
GSP	gross state product
Guideline 14	Essential Services Commission of Victoria (ESCV), *Electricity Industry Guideline No. 14—Provision of Services by Electricity Distributors—Issue 1*, April 2004
GWh	Giga watt hour
HBRA	hazardous bushfire risk areas
HRC	Hot Rolled Coil

IEEE	Institute of Electrical and Electronic Engineers
IHD	In home display
Impaq	Impaq Consulting
IMRR	Interval meter reassignment requirements
IPART	Independent Pricing and Regulatory Tribunal
ISF	Institute for Sustainable Futures
IT	information technology
IVR	Interactive Voice Response
JAM	Jemena Asset Management
KPI	Key Performance Indicator
L factor	Licence fee factor
LBRA	low bushfire risk areas
LIBOR	London Interbank Offered Rate
LME	London Metal Exchange
LPI	labour price index
MAIFI	Momentary Average Interruption Frequency Index
MAV	Municipal Association of Victoria
MD	Maximum demand
MED	Major Event Day
MEPS	Minimum Energy Performance Standards
MOU	Memorandum of Understanding
MRET	Mandated Renewable Electricity Target
MRP	Market risk premium
MSATS	Market settlement and transfer solution procedures
MTR	Maximum transmission revenue
MV80	Mercury Vapour 80
MVa	mega volt amperes
MW	mega watt
MWh	mega watt hour

NDSC	Negotiated Distribution Service Criteria
NECA	National Electrical Contractors Association
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERA	National Economic Research Associates, Inc.
NGERS	National Greenhouse and Energy Reporting Act 2007
NIEIR	National Institute of Economic and Industry Research
NPV	Net present value
NSLP	Net system load profile
NSW	New South Wales
NYMEX	New York Mercantile Exchange
Ofgem	Office of Gas and Electricity Markets
OMR	Operation, Maintenance and Repair
opex	operating expenditure
Origin	Origin Energy
PB	Parsons Brinckerhoff Strategic Consulting
PE cells	photo-electric cells
PFIT	Premium feed-in tariff
PLC	Public Lighting Code
PoE	Probability of exceedence
POEL	private overhead electric lines
PSAIDI	planned SAIDI
PTRM	Post tax revenue model
PV	photovoltaic
QCA	Queensland Competition Authority
QLD	Queensland

RAB	Regulatory asset base
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
repex	Replacement expenditure
revised Order	The Order in Council made on 28 August 2007 by the Victorian Governor in Council under sections 15A and 46D of the Electricity Industry Act 2000, as amended on 25 November 2008, 22 January 2009 and 31 March 2009.
RIN	Regulatory information notice
RIS	Regulatory impact statement
RIT–D	Regulatory Investment Test for Distribution
RMA	Road Management Act 2004 (Vic)
ROS	Reliability of Supply
SA	South Australian
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCONRRR	Steering Committee On National Regulatory and Reporting Requirements
SECV	State Electricity Commission Victoria
SFTUCF	S factor true up correction factor
SGC	Streetlight Group of Councils
SHP	Sodium High Pressure
SIR	Service and Installation Rules
SKM	Sinclair Knight Merz
SMS	short message service
SOO	Statement of opportunities (AEMO)
SORI	Statement of Regulatory Intent
STPIS	Service Target Performance Incentive Scheme
T5	energy efficient T5
TEC	Total Environment Centre
Tenix	Tenix Alliance Pty Ltd

TEV	transient earth voltage
TFP	Total Factor Productivity
TNSP	Transmission Network Service Provider
TOU	Time of use
TUoS	Transmission use of system
TWI	Trade weighted index
UED	United Energy Distributors
UK	United Kingdom
USA	United States of America
USD	US dollar
VBRC	Victorian Bushfires Royal Commission
VCOSS	Victorian Council of Social Services
VCR	Value of Customer Reliability
VECCI	Victorian Employers Chamber of Commerce and Industry
VEET	Victorian Energy Efficiency Target
VSPLAG	Victorian Sustainable Public Lighting Action Group
WACC	Weighted average cost of capital
WAPC	Weighted average price cap
WMTS	West Melbourne terminal station
WTI	West Texas Intermediate
ZSS	zone substation