PRELIMINARY DECISION
Powercor distribution determination 2016 to 2020

Overview

October 2015

AUSTRALIAN ENERGY REGULATOR

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Invitation for submissions

Energy consumers and other interested parties are invited to make submissions on our preliminary decisions for the Victorian electricity distribution service providers by **Wednesday 6 January 2016.**

We will consider and respond to submissions in our final decisions in late April 2016.

We prefer that all submissions are in Microsoft Word or another text readable document format. Submissions on our preliminary decisions should be sent to: VICElectricity2016@aer.gov.au

Alternatively, submissions can be sent to:

Mr Chris Pattas
General Manager
Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

We prefer 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 should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (October 2008), which is available on our website.

We will hold a pre-determination conference on 17 November 2015 from 9.30am. If you are interested in attending this forum, have any queries about this preliminary decision or about lodging submissions, please send an email to: VICelectricity2016@aer.gov.au.

Note

This attachment forms part of the AER's preliminary decision on Powercor's revenue proposal 2016–20. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 - Annual revenue requirement

Attachment 2 - Regulatory asset base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency benefit sharing scheme

Attachment 10 - Capital expenditure sharing scheme

Attachment 11 - Service target performance incentive scheme

Attachment 12 - Demand management incentive scheme

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Attachment 14 - Control mechanism

Attachment 15 - Pass through events

Attachment 16 - Alternative control services

Attachment 17 - Negotiated services framework and criteria

Attachment 18 - f-factor scheme

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	advanced metering infrastructure
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure

Shortened form	Extended form
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Introduction

We, the Australian Energy Regulatory (AER), are responsible for the economic regulation of electricity distribution systems in Australia, except for Western Australia.

Powercor is one of five distribution network service providers (distributors) in Victoria and is responsible for providing electricity distribution services in the western part of Victoria. We regulate the revenues Powercor and other electricity distributors can recover from their customers.

Powercor submitted its regulatory proposal in April 2015 for the 2016–20 regulatory control period.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework governing electricity networks. In regulating Powercor, we are guided by the National Electricity Objective (NEO), as set out in the NEL. The NEO 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; and
>
> the reliability, safety and security of the national electricity system.[1]

We apply incentive regulation in making our decision on a distributor's revenue—in accordance with the NER.[2] Incentive regulation encourages distributors to spend efficiently and to share the benefits of efficiency gains with consumers.

While we approve an overall revenue allowance for Powercor, this does not bind the business to a particular operating budget. We determine the overall revenue allowance that is based on a forecast of efficient capital and operating expenditures that would be required by Powercor in prudently providing distribution services and fulfilling its obligations. The regime provides incentives for Powercor to outperform those forecasts, while delivering safe, reliable and secure services to its customers.

If in assessing Powercor's regulatory proposal we do not accept that its forecast revenue complies with the requirements of the NER, we must substitute an alternative amount of revenue that we are satisfied does comply. In doing so, we must undertake this assessment and make this decision in a manner that will or is likely to contribute to the achievement of the NEO and, where there are two or more possible decisions that

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1 NEL, s. 7.

2 NER, cl. 6.2.6(a) states that for standard control services, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C (Building Block Determinations for standard control services). Further revenue and pricing principles (RPPs) state 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.

will do so, make the decision that we are satisfied will contribute to the greatest degree (see section 5 of this overview).

We received submissions from various stakeholders on Powercor's proposal. We have published these submissions and Powercor's regulatory proposal on our website.

This overview, together with its attachments, constitutes our preliminary decision on Powercor's regulatory proposal.

1.1 Victorian electricity distribution

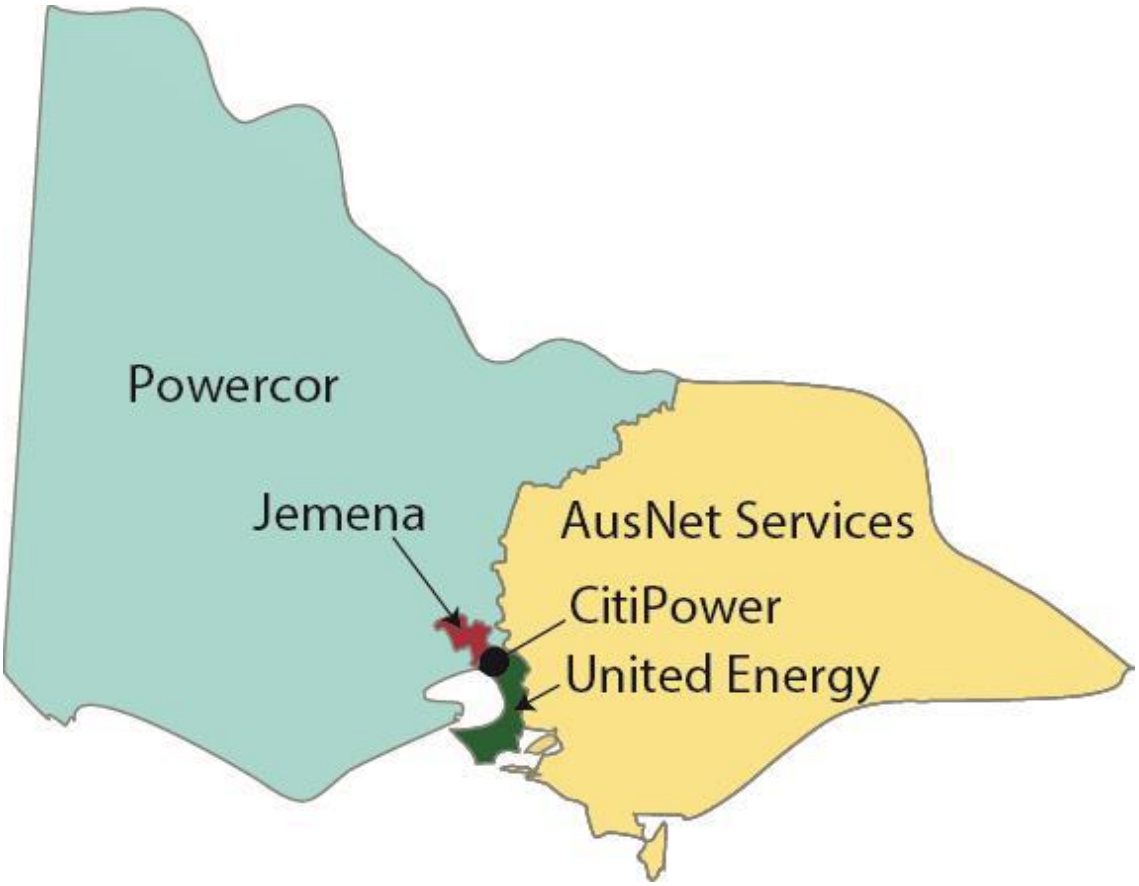
The electricity industry in Victoria is divided into four distinct parts, with a specific role for each stage of the supply chain—generation, transmission, distribution and retail.

Electricity distributors, which are the focus of this review, convert electricity from the transmission network into medium and low voltages and deliver that electricity to homes and businesses across Victoria. Each of Victoria's five distributors serves a different geographic area of Victoria:

- AusNet Services operates in the eastern part of Victoria
- CitiPower operates in the urban and CBD parts of Melbourne
- Jemena operates in a section north west of Melbourne
- Powercor operates the western part of Victoria
- United Energy operates in the south-eastern suburbs of Melbourne

The following map (figure 1) shows the geographic reach of each of these networks. Importantly, AusNet Services and Powercor predominantly serve rural and regional Victoria, whereas Jemena, United Energy and CitiPower predominantly serve urban customers.

Figure 1: Victorian electricity distribution networks



1.2 Structure of overview

This overview provides a summary of our preliminary decision and its constituent components. It is structured as follows:

- Section 2 provides a high-level summary of our preliminary decision and the key issues.
- Section 3 provides a break-down of our revenue decision into its key components. We determine revenue using the building block approach and this section details the approved amount for each building block.
- Section 4 sets out our preliminary decision on classification of services, control mechanisms and incentive schemes that will apply to Powercor. These are the decisions we make in addition to the building block revenue determination.
- Section 5 explains our views on the regulatory framework and the NEO.
- Section 6 outlines the consultation process we undertook in reaching our preliminary decision.
- Appendix A contains the full list of constituent components for our preliminary decision.

In our attachments we set out detailed analysis of the constituent components that make up Powercor's proposal and our decision on each of them.

2 Preliminary decision

Our preliminary decision is that Powercor can recover $3085.8 million ($ nominal) from consumers over the 2016–20 regulatory control period, which begins on 1 January 2016. This is a 15.5 per cent reduction to Powercor's proposed revenue allowance of $3652.9 million ($ nominal). Our preliminary decision allows Powercor to recover 5.7 per cent less revenue from its customers in 2016 than it did in 2015.

We are satisfied that the total revenue set in our preliminary decision is sufficient for Powercor, acting prudently, to recover the efficient costs of providing safe and reliable electricity services. That is, our preliminary decision contributes to the achievement of the National Electricity Objective.

In this section, we provide a snapshot of our preliminary decision, including the impact we expect it will have on residential electricity bills (section 2.1), and highlight key issues considered as part of this review (section 2.2). Further, we set out the timeline, including for submissions to this preliminary decision, and briefly note the transitional rules that apply to this process (section 2.3).

This section aims to be accessible to a broad audience. See section 3 of this overview for a more technical discussion of the building block model components. We use the building block model to determine how much revenue a business requires to cover its efficient costs—as required under the National Electricity Rules.

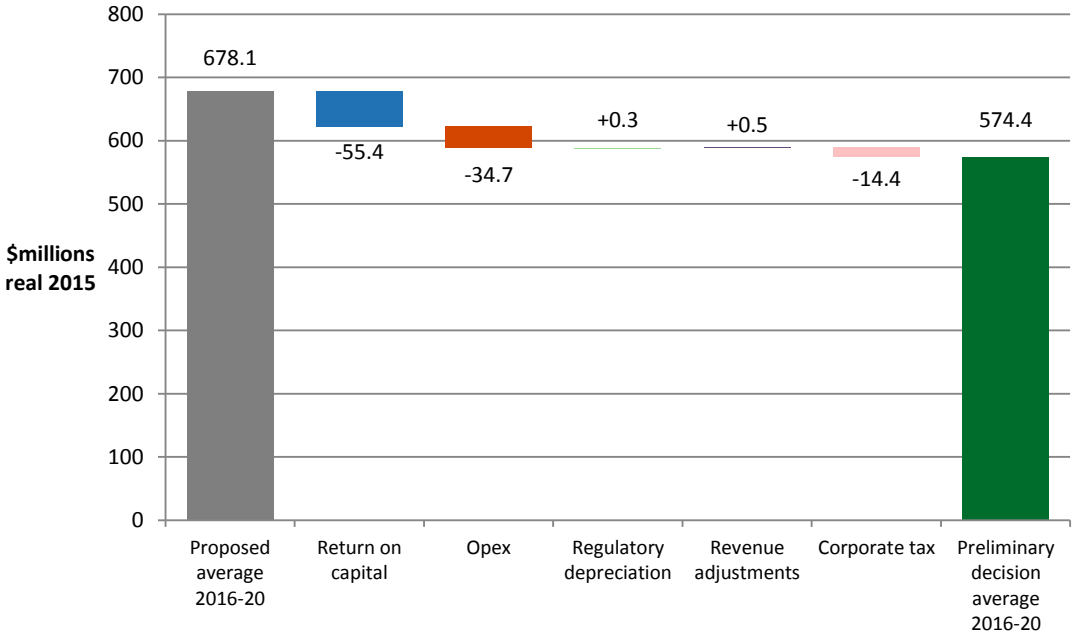
2.1 Snapshot of preliminary decision

Figures 2 and 3 compare our preliminary decision to Powercor's proposal—broken down by the various building block components. They highlight that the allowed rate of return—which feeds into the return on capital—is the key difference between our preliminary decision and Powercor's proposal.

Our decision also reduces Powercor's proposed operating expenditure (opex) and capital expenditure (capex) by 12.5 per cent and 19.7 per cent, respectively.

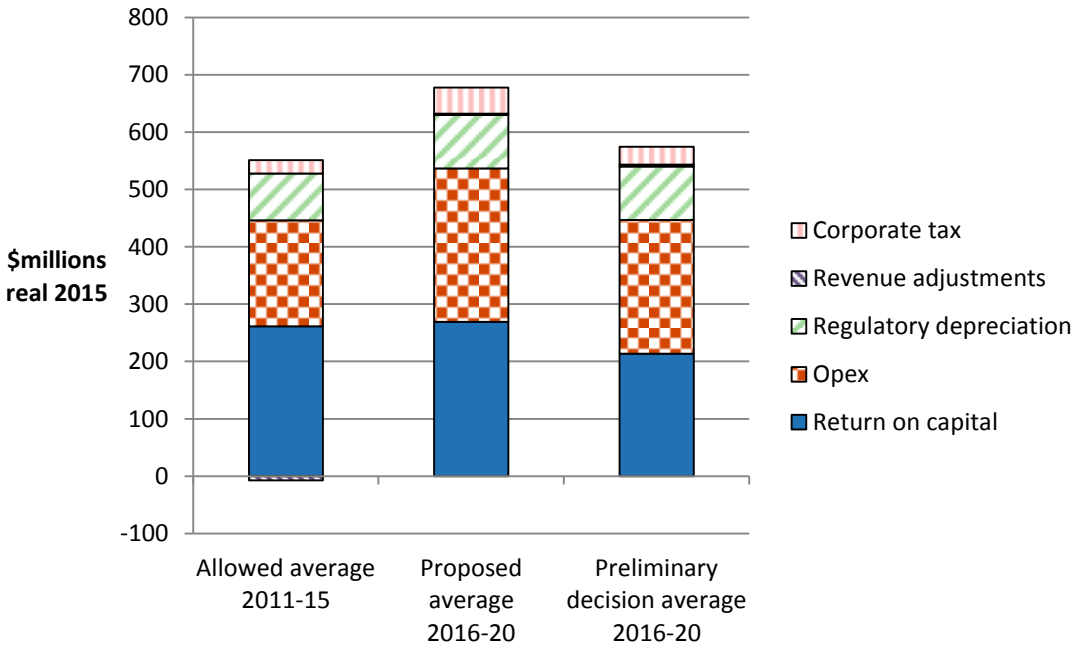
Our assessment has also found that Powercor has generally improved reliability outcomes over 2011–14 compared to the previous period.

Figure 2 AER's preliminary decision and Powercor's proposed annual building block costs ($ million, 2015)



Source: AER analysis.

Figure 3 AER's preliminary decision on constituent components of total revenue ($ million, 2015)



Source: AER analysis.

Expected impact of decision on residential electricity bills

Distribution charges represent approximately 25 per cent, on average, of the annual electricity bill for Powercor customers for standard control services.[3] Other factors may affect a customer's electricity bill, such as their consumption, their specific tariff, the wholesale price of electricity, or changes in the retail margin.

In 2016 we expect a typical residential electricity bill to decrease by approximately 1.8 per cent. We expect a similar reduction in 2017 and then for bills to remain relatively stable for the remaining three years of the period.

Table 1 shows the estimated impact of our preliminary decision on the average residential and small business customers' annual electricity bills in Powercor's network area over the 2016–20 regulatory control period, compared with what was proposed by Powercor. Our bill impact estimates are indicative because distribution network charges form only part of the final bill paid by customers, and individual customers' actual bills will depend on their usage patterns and the structure of their tariffs.

Table 1 AER's estimated impact of its preliminary decision on the average residential and small business customers' electricity bills in Powercor's network for the 2016−20 period ($ nominal)

	2015	2016	2017	2018	2019	2020
AER preliminary decision						
Residential annual bill	1816[a]	1784	1755	1761	1767	1774
Annual change[c]		–32 (–1.8%)	–29 (–1.6%)	6 (0.4%)	6 (0.4%)	7 (0.4%)
Small business annual bill	3998[b]	3927	3863	3877	3891	3906
Annual change[c]		–71 (–1.8%)	–64 (–1.6%)	14 (0.4%)	14 (0.4%)	15 (0.4%)
Powercor proposal						
Residential annual bill	1816[a]	1804	1823	1842	1861	1881
Annual change[c]		–12 (–0.6%)	19 (1.1%)	18 (1.1%)	19 (1.1%)	20 (1.1%)
Small business annual bill	3998[b]	3972	4014	4054	4096	4141
Annual change[c]		–26 (–0.6%)	42 (1.1%)	40 (1.1%)	42 (1.1%)	45 (1.1%)

Source: AER analysis, ESC, Victorian Energy Retailers Comparative Performance Report – Pricing 2013-14, October 2014.

(a) Based on average of standing offers at June 2015 on Switchon comparison tool (postcode 3550) using annual bill for typical consumption of 4690 kWh per year.

[3] Standard control services represent the bulk of a distributor's services, provided to all customers connected to its network. Metering services in Victoria are not classified standard control, so the bill impacts shown here do not incorporate reductions in annual metering charges.

(b) Based on average of standing offers at June 2015 on Switchon comparison tool (postcode 3550) using annual bill for typical consumption of 12020 kWh per year.

(c) Annual change amounts and percentages are indicative. They are derived by varying 2015 bill amounts in proportion with total annual regulated revenue divided by forecast demand. Actual bill impacts will vary depending on electricity consumption, tariff class and other variables.

2.2 Key aspects of our preliminary decision

The total revenue approved in our preliminary decision reflects a number of factors:

- Based on our benchmarking results we find that Powercor has been operating relatively efficiently—such that we can use Powercor's 2014 opex as a basis for assessing overall forecasts going forward. However, we still must assess the prudency and efficiency of proposed forecast cost increases going forward (section 2.2.1).
- Advanced metering infrastructure is classified as an 'alternative control service'. The associated efficient costs are not included in Powercor's allowed revenue of $3085.8 million for standard control services—but rather are recovered under a separate annual metering charge (section 2.2.2).
- We have approved sufficient capital expenditure to allow Powercor to maintain the quality, reliability and security of electricity supply, among other things (section 2.2.3).
- There have been changes to Powercor's operating environment that impact its underlying cost drivers, which is reflected in the lower revenue allowance for 2016–20 compared to 2011–15 (section 2.2.4).

2.2.1 Past operating efficiency

In recent years, we have expanded our regulatory toolkit to include greater use of benchmarking—particularly for operating expenditure (opex). Benchmarking is a way of determining how well a network business is performing against other distributors in the National Electricity Market and over time, and it provides valuable information on what is considered to be 'best practice'.

Our opex benchmarking results show Powercor is currently one of the most efficient service providers in the National Electricity Market. Further, we find that Powercor has generally improved reliability outcomes over 2011–14 compared to its performance in the previous period.

We consider Powercor has been responsive to the incentives of the regulatory regime. The network businesses are incentivised to spend efficiently and to share the benefits of efficiency gains with consumers. Businesses that are able to improve their efficiency are rewarded with higher profits for a period of time. Productivity savings are passed on to consumers through the Efficiency Benefit Sharing Scheme (EBSS), and are reflected in Powercor's base opex when we forecast opex for future regulatory periods.

We therefore have used Powercor's revealed (past actual) costs as the starting point for forecasting efficient opex.

We have then accounted for any changes in efficient costs in the base year and each year of the forecast regulatory control period. Overall, we consider that Powercor has proposed more revenue than is actually required to operate its network prudently and efficiently. As discussed in section 2.2.4, we do not consider there are significant 'step changes' required to Powercor's opex. We have made some adjustments for changes in output and real prices over the 2016–20 period. Further, Powercor allocated opex for Advanced Metering Infrastructure (AMI) to standard control services. We classified these costs under 'alternative control services', which means ongoing AMI costs will be recovered by Powercor through a separate annual metering charge.

2.2.2 Advanced metering infrastructure

The advanced metering infrastructure rollout that commenced in 2009 under an Order in Council is now largely completed. So, we expect the capex component for metering to fall in 2016–20 as the Victorian distributors enter a 'business-as-usual' phase, although opex is still required to maintain the metering infrastructure.

We have approved a revenue allowance for AMI of $351.0 million ($ nominal) for 2016–20, which includes $33.5 million ($2015) of capex and $91.7 million of opex. The completion of the rollout means Powercor needs less revenue to provide metering services. Revenue for metering will decrease by around 15 per cent from 2015 to 2016. This will lead to a similar reduction in annual metering charges in 2016.

2.2.3 Approved capital expenditure

We approve $1610.4 million of capital expenditure (capex), which is a reduction of 19.7 per cent to what Powercor proposed. This provides sufficient funds to allow Powercor to augment the network where necessary, replace assets that have reached the end of their economic life, and invest in information and communication technology to manage the transition to a smarter network, among other things.

Our role is to assess Powercor's proposed total capex for 2016–20 against the (capex) criteria set out in the National Electricity Rules (NER). That is, we must form a view on whether Powercor's proposed total capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives given a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives. The capex objectives are to: meet expected demand; comply with all applicable regulatory obligations; and (broadly) maintain the quality, reliability, safety and security of supply and the distribution system.

We applied our various assessment techniques in considering Powercor's proposal. For example, we considered past trends in actual and forecast capex, undertook 'category analysis' to compare expenditures across businesses and over time, and used predictive modelling. This analysis, together with advice from our expert consultants and input from stakeholders, has informed our view on whether Powercor's proposal reasonably reflects the capex criteria in the NER at the total capex level.

Consumers should pay no more than necessary for the safe and reliable delivery of electricity network services. Powercor proposed capex of $2006.3 million. Although we made some adjustments, we are reasonably satisfied that the majority of capex proposed by Powercor for 2016–20 is prudent and efficient and, therefore, is in the long term interests of consumers.

2.2.4 Less revenue required in current operating environment

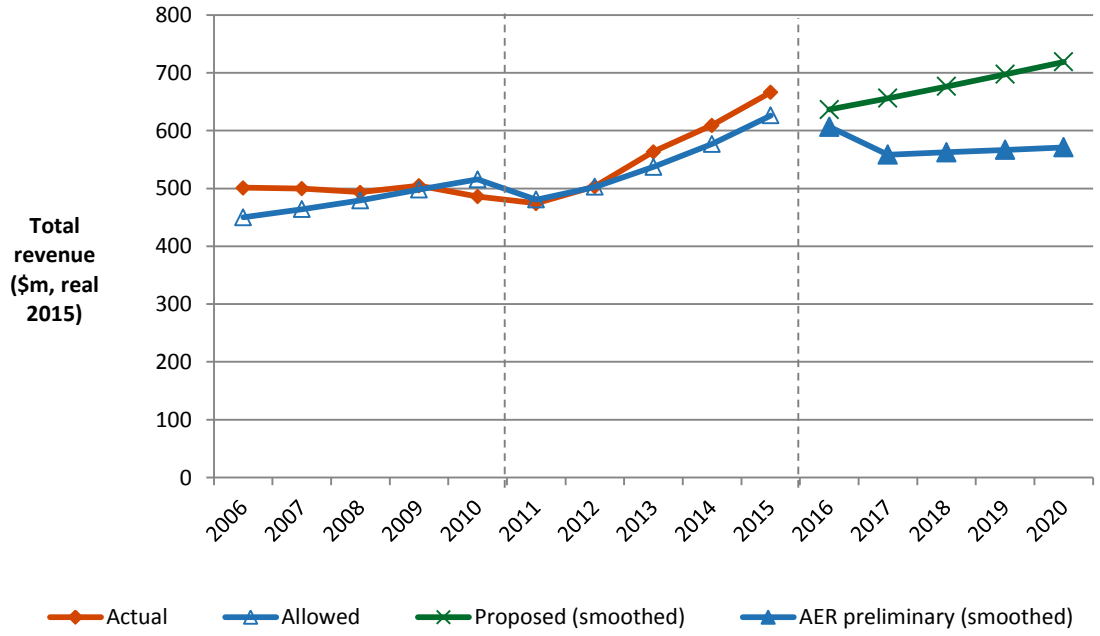
Powercor's annual revenue increased each year from 2011 to 2015. This preliminary decision results in a gradual fall in revenue over 2016–20 (figure 4), which reflects a number of factors that impact on Powercor's underlying costs, including:

- an improved investment environment compared to the previous regulatory period, which translates to lower financing costs necessary to attract efficient investment
- demand for electricity which is expected to be relatively flat going forward, which means less pressure on Powercor to expand the capacity of its network compared to previous regulatory periods
- changes to the Value of Customer Reliability, which reduces the need to build new infrastructure to meet customers' expectations of reliable electricity
- the asset replacement cycle, whereby increased replacement capex is required to manage deterioration in asset condition because a greater proportion of its assets are reaching the end of their economic life
- fewer new regulatory obligations imposed on Powercor, which means there has not been the same 'step' increase in the business' costs as there was in the previous regulatory period.

Most of the above factors reduce Powercor's underlying costs compared to the previous regulatory period. Overall, we consider that Powercor, operating prudently and efficiently, can provide safe and reliable distribution services over 2016–20 with less revenue when compared to 2011–15.

It is noted that a contingent project allowance is included in this preliminary decision for new regulatory obligations that may be imposed on Powercor in 2016–20 by the Victorian Government—these relate to further initiatives stemming from the 2009 Victorian Bushfires Royal Commission. Although the full scope of the new obligations and their likely cost impact on Powercor are not currently known, the NER include the contingent project mechanism which may apply when a need for additional capital is likely to arise in the next period. This allowance is subject to further review before it is activated to ensure the costs are prudent and efficient. Further, we have accepted additional capex of $136 million that is driven by a bushfire safety mitigation program, which is based on a mandatory obligation to undertake this work.

Figure 4 Powercor's past total revenue, proposed total revenue and AER total revenue allowance ($ million, 2015)



Source: AER analysis.

Network funding costs are lower

The rate of return provides a network business with revenue to service the interest on its loans and to give a return on equity to shareholders. The allowed rate of return is a key determinant of allowed revenue. The differences in the rate of return we determine and those proposed by the businesses may appear small—a percentage point or two. However, even a small difference can have a big impact on revenues. This is because the businesses have raised large amounts of funds from lenders and other investors in the past, which is to be expected given the capital intensive nature of the sector. These fund raisings have to continue to be financed, as well as financing of any new capital spending.

The rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk to the distributor in respect of the provision of distribution services. The NER refers to this requirement as the 'allowed rate of return objective'.

Prevailing market conditions for debt and equity heavily influence the rate of return. Financial conditions have changed since our last decision for Powercor in October 2010, which covered the 2011–15 regulatory control period. This is reflected in a lower rate of return in this preliminary decision. Interest rates are lower and financial market conditions are more stable. This means that the cost of debt and the returns required to attract equity are lower. These factors should be reflected in the rate of return.

Our preliminary decision is for a rate of return of 6.02 per cent (for 2016)[4]—compared to 9.49 per cent we set in the 2011–15 regulatory control period.

We set out our approach to determining the rate of return in the Rate of Return Guideline (Guideline) we published in December 2013. We undertook significant consultation in developing this Guideline. Although it is not binding, the distribution businesses must provide reasons to justify any departure from the Guideline.

Powercor proposed a rate of return of 7.20 per cent for 2016–20. It proposed that we depart from the Rate of Return Guideline. We have considered Powercor's arguments and supporting information, but do not find them sufficiently compelling for us to depart from the Guideline. Advice from the Consumer Challenge Panel, and submissions by the Consumer Utilities Advocacy Centre, Victorian Energy Consumer and User Alliance, Victorian Government, Energy Retailers Association of Australia and Origin Energy broadly considered that the Victorian distributors' proposals should not have departed from the Guideline, and that their proposed rates of return are excessive given the current investment environment.[5] For example, VECUA stated:

> The distributors' WACC proposals are excessive and are based on major unjustified departures from the AER's Rate of Return Guideline—a guideline that was developed through extensive consultation over a 12 month period with a broad range of stakeholders, including the Victorian distributors.
>
> By contrast, the Victorian distributors' proposed departures have not been submitted to any rigorous analysis or stakeholder consultation. Most of the information used by the Victorian distributors to support their departures was already considered by the AER during the development of the rate of return guideline.[6]

This preliminary decision on rate of return is consistent with our mid-2015 final decisions for the New South Wales and ACT electricity distribution, and New South Wales gas distribution, network businesses. These network businesses have appealed many aspects of our rate of return decisions to the Australian Competition Tribunal. The Victorian electricity distribution businesses are participating in the appeals process—arguing that the rate of return we set is too low. The Australian Competition Tribunal's process had not been finalised at the time of this preliminary decision.

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4 For the remaining years of the regulatory control period, we will update the rate of return annually.

5 Consumer Challenge Panel Sub-Panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015; Consumer Utilities Advocacy Centre, *Re: Victorian electricity distribution pricing review (EDPR), 2016 to 2020*, 13 July 2015; Victorian Energy Consumer and User Alliance, *Submission to the AER, Victorian Distribution Networks' 2016–20 Revenue Proposals*, July 2015; Victorian Department of Economic Development, Jobs, Transport & Resources, *Submission to Victorian electricity distribution pricing review 2016 to 2020*, July 2015; Energy Retailers Association of Australia, *Re: Issues paper – Victorian electricity distribution pricing review 2016-2020*, 13 July 2015; Origin Energy, *Re: Submission to Victorian Electricity Distributors Regulatory Proposals*, 13 July 2015.

6 Victorian Energy Consumer and User Alliance, *Submission to the AER, Victorian Distribution Networks' 2016–20 Revenue Proposals*, July 2015, p. 3.

Maximum demand is not expected to grow

Maximum demand for electricity is a key driver of investment in network capacity and expansion. Because of this, forecasts of maximum demand are fundamental to Powercor's forecast expenditure, and to our assessment of that forecast expenditure.

Powercor forecasts growth in maximum demand over 2016–20. Powercor's demand forecasts for the 2016–20 period are higher than the actual demand observed for its network over the last two regulatory periods. Powercor forecasts a return to demand growth on the network similar to that experienced prior to 2009, which contrasts to the recent flattening of demand over 2011–15. Powercor stated that demand will increase due to:

- increases in the frequency and duration of heatwaves that will increase the use of air-conditioners by commercial businesses and residential households
- population growth in the western suburbs of Melbourne and the Greater Geelong region
- expansion and additional capacity required in the agricultural sector, particularly in Warrnambool and Murray River Regions.[7]

As we set out in Attachment 6, there have been developments in the Australian and Victorian electricity markets over recent years that have influenced electricity consumption and maximum demand patterns. For example, household installations of photo-voltaic (PV) cells and the increased focus on energy efficiency have changed historic demand growth patterns. Together with broader macroeconomic factors, we consider that this has led to a softening of both actual maximum demand growth and forecasts for future growth. Similar observations are made by stakeholders in submissions to this process.

In this context, we consider Powercor's forecasts of maximum demand likely do not reflect a realistic expectation of demand over the 2016–20 period. Powercor's forecast appears to assume that the longer-terms drivers of maximum demand will continue into the future, regardless of the observed change in the pattern of consumption and maximum demand in recent years.

In coming to this view, we considered Powercor's forecasting methodology and compared Powercor's proposal to the Australian Energy Market Operator's (AEMO's) independent forecasts of maximum demand. AEMO publishes forecasts and planning information in its role as the National Energy Market Operator and planner. We use AEMO's maximum demand forecasts as an independent reference in regulatory determination processes.

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[7] Powercor, *Regulatory Proposal 2016–20*, April 2015, pp. 88-89.

We consider AEMO's independent forecasts better explain the actual demand pattern seen across Powercor's network. While not without its limitations, we consider that AEMO's forecasts better reflect recent changes in the electricity market.

This means that Powercor is likely to be under less pressure to expand its network than in previous years to meet the needs of additional customers or any increased demand from existing customers. While we accept there will remain areas of its network that require expansion to meet localised growth in maximum demand, we find that Powercor should not require significant increases in overall capex to expand its network. Therefore, we consider there is the potential to prudently delay some of Powercor's proposed network augmentation projects. We have taken this into account as part of our assessment of Powercor's expenditure forecasts.

We understand that Powercor—and the other Victorian electricity distribution businesses—are in the process of updating their demand forecasts as part of their annual network planning processes. We also note that in September 2015, AEMO published updated connection point demand forecasts for Victoria. These forecasts took into account actual 2015 summer demand data and some revisions to its forecasting methodology. We have not been able to take AEMO's updated connection point forecasts into account for this preliminary decision. We will revisit Powercor's updated demand forecast in its revised regulatory proposal.

Customers are not willing to pay more for increased reliability

In planning network augmentation, the Victorian businesses apply a measure of customers' willingness to pay, in dollar terms, for the reliable supply of electricity—known as the Value of Customer Reliability (VCR). This allows the businesses to compare the economic cost to customers from network outages against the cost of augmenting the network. This is a commonly used assessment and reflects good industry practice.

AEMO recently completed a National Electricity Market-wide review of the VCR. The study was requested by the COAG Energy Council. The purpose of the review was to improve the understanding of the level of reliability that customers expect by producing a range of VCR values for residential and business customers across the National Electricity Market. This study found that the VCR in Victoria has declined since the previous study conducted in 2014,[8] which reduces the need to build new infrastructure to meet customers' expectations of reliable electricity.

Powercor applied AEMO's Victorian VCR in its expenditure forecasts for 2016–20. On this basis, we consider that Powercor has prudently identified the need to augment specific parts of its network to meet customer expectations of reliable electricity.

[8] AEMO, *Value of Customer Reliability Review – Final Report*, September 2014, p. 1.

Powercor stated the large reduction in the AEMO VCR values between 2013 and 2014 resulted in the deferral of some anticipated projects from the 2016–20 regulatory control period to 2021 and beyond.[9]

More network assets are reaching the end of their useful life

Network assets do not last forever. As assets age and deteriorate the cost of maintaining the asset in acceptable condition and the probability of outright failure increases. At some point it becomes economically sensible to replace existing assets.

Major expansions in the distribution networks—due to factors such as customer or demand growth—can lead to large variations in investments for a period of time. This may then fall away, and be followed by relatively moderate network investment for a number of years. This brings about a lumpy pattern of investment over the life of the network.

Replacement may occur when an asset fails, when the maintenance costs become unacceptably high, or a condition assessment may find it is likely to fail soon and replacement is the most economic option. It may also occur because jurisdictional safety regulations dictate that the asset is no longer considered to be safely operated on the network, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network.

In general, the majority of network assets will remain in efficient use for far longer than a single five year regulatory period. Many of these assets have economic lives of 50 years or more. As a consequence, distributors will only need to replace a portion of their network assets in each regulatory control period.

Powercor's replacement expenditure (or repex) has been trending up over time and is forecast to increase further over 2016–20. Powercor states it has an ageing network, with the majority of its current assets installed during the 1960s, 1970s and 1980s.[10] Further, Powercor stated the increasing failure rate of its 'poles and wires' assets is a key driver of its replacement expenditure.[11]

Our predictive repex model can be used to forecast a reasonable amount of repex Powercor would require if it maintains its current risk profile for condition-based replacement into the next regulatory period. The model takes into account the age profile of Powercor's assets and when it is likely to replace the assets.

Having considered its proposal, we accept that Powercor requires increased repex over 2016–20—compared to 2011–15—to manage deterioration in asset condition because a greater proportion of its assets are reaching the end of their economic life. Although we made some adjustments, we have approved the majority of Powercor's

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9 Powercor, *2016-2020 Price Reset, Appendix E Capital expenditure*, April 2015, p. 68.

10 Powercor, *Regulatory Proposal*, 30 April 2015, p. 110.

11 Powercor, *Regulatory Proposal*, 30 April 2015, p. 112.

proposed repex based on our predictive modelling, the advice of our expert consultants, trend analysis, asset health indicators, and consideration of the Consumer Challenge Panel's advice and stakeholder submissions.

Fewer new regulatory obligations

In its proposal, Powercor has raised a number of cost drivers that it considers will require increased opex and capex over the forecast period. For example, Powercor proposes increased funding for step changes, such as new customer information and relationship management systems, new mobile devices, and IT security monitoring.[12] Capex can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security requirements.

For opex, we refer to these cost drivers as possible 'step changes'. Step changes may be for cost drivers such as new, changed or removed regulatory obligations, or efficient capex/opex trade-offs.[13] We typically compensate a network business for step changes only if efficient base year opex, and the rate of change in opex of an efficient service provider, do not already compensate the business for the proposed costs.[14]

We find there are very few changes in the external environment, such as new regulatory obligations, that require a step change in opex for Powercor, especially compared to the previous regulatory period. Powercor proposed $26.1 million for step changes in opex—of which we accepted $3.1 million. The base level of opex for the most part is sufficient for Powercor to operate a safe and reliable network for the 2016–20 period. Moreover, we find some proposed step changes are driven by Powercor's internal management decisions and are 'business-as-usual'.

That said, we have accepted additional capex of $136 million that is driven by a bushfire safety mitigation program for the 2016–20 period. Powercor has demonstrated it has a mandatory obligation to undertake this new work, which follows from the 2009 Victorian Bushfires Royal Commission.

Powercor may also face some anticipated, as opposed to known, changes to legislation. Where there is a clear prospect of a change in regulation, such as for some new bushfire safety related regulatory obligations, additional costs may arise. Powercor may provide information in its revised proposal on anticipated regulatory obligations so that we may consider them as contingent projects in our final decision.

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12 Powercor, *Regulatory Proposal*, 30 April 2015, pp. 187–190.

13 We expect total opex to be relatively stable over time. For example, as some non-recurrent costs increase, others will fall away. Efficient discretionary changes in inputs—that are not required to increase output—should have a net negative impact on expenditure over the long term, as the business seeks to improve its efficiency.

14 AER, *Expenditure Forecast Assessment Guideline*, November 2013, p. 24.

2.3 Process timeline and transitional rules

We began the process of reviewing Powercor's regulatory proposal in May 2015. Powercor's revised proposal and submissions on our preliminary decisions are due by 6 January 2016. We will then give third party stakeholders an opportunity to comment on the revised proposals by 4 February 2016. By the same date, we will allow further submissions from all stakeholders, including the distribution businesses, on the submissions made by third party stakeholders to the preliminary decisions. Our final decision is due to be released in late April 2016. Table 2 lists the key dates.

Table 2 Key dates

Task	Date
Businesses submitted regulatory proposals to AER	30 April 2015
AER released Issues paper	9 June 2015
AER held public forum	22 June 2015
Submissions on regulatory proposals received	13 July 2015
AER preliminary decisions	29 October 2015
AER to hold conference to explain preliminary decisions	17 November 2015
Submissions on preliminary decisions due	6 January 2016
Businesses to submit revised regulatory proposals to AER	6 January 2016
Further submissions due, including on revised proposals*	4 February 2016
AER to release final decisions	End of April 2016

Transitional rules for the Victorian electricity businesses

In November 2012, the AEMC introduced major changes to the economic regulation of electricity distributors under chapter 6 of the NER.[15] To allow consumers to receive the benefit of the new rules the AEMC made transitional rules under chapter 11 of the NER. The transitional provisions in chapter 11 of the NER effectively provide that a modified version of chapter 6 (version 58) governs the making of the Victorian distribution determinations.

Our preliminary decision for the 2016–20 regulatory control period will be the basis used for approving network prices in 2016. As required by the 'transitional arrangements' in the NER, we will then revoke the preliminary decision and substitute it with a new distribution determination which takes effect at the date it is made and applies in respect of the 2016–20 regulatory control period (referred to as our final decision). The new distribution determination will provide for a revenue adjustment, as

[15] AEMC, *Final Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

specified in the NER, that incorporates adjustments of Powercor's revenues or prices over the regulatory control period to account for differences between the amount of the revenues and prices that we approved for the 2016 regulatory year in the preliminary decision and in the final decision.

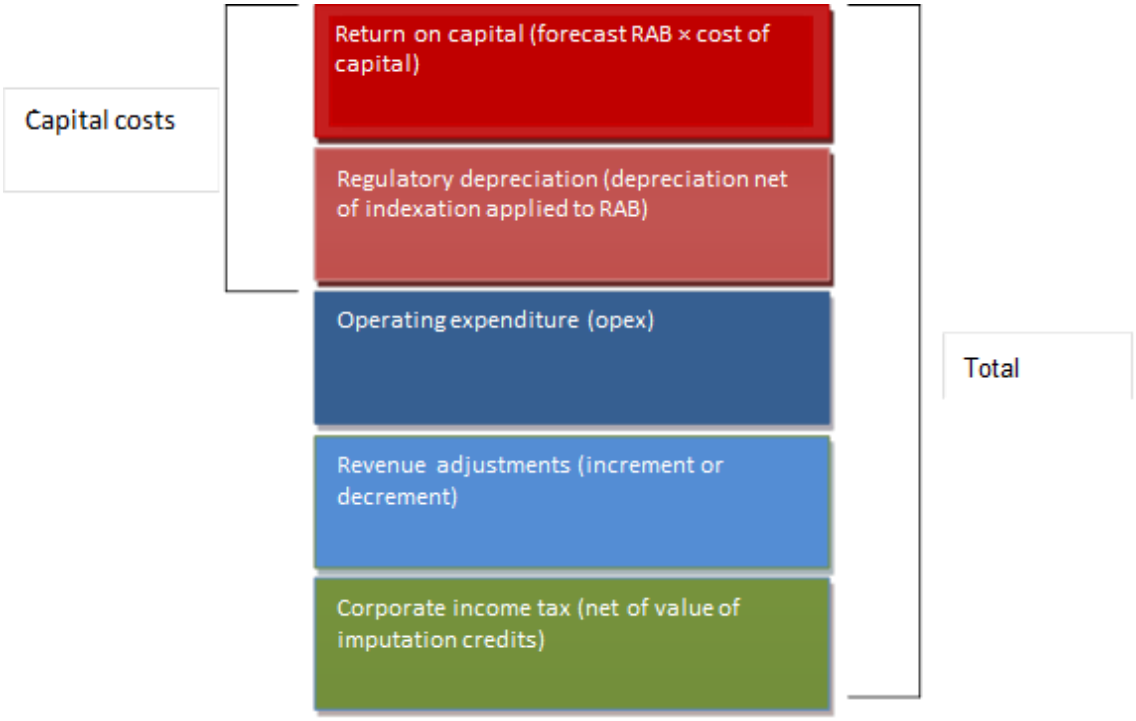
3 Key elements of decision on Powercor's revenue

We use the building block approach to determine Powercor's annual revenue requirement. The building block costs, illustrated in figure 5, include:

- a return on the regulatory asset base (RAB) (return on capital)
- depreciation of the RAB (return of capital)
- forecast opex
- revenue increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of the RAB and therefore, the revenue generated from the return on capital and return of capital building blocks.

Figure 5 The building block approach for determining total revenue



In setting our alternative overall revenue allowance for Powercor of $3085.8 million ($ nominal) for the 2016–20 regulatory control period we:

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation Guidelines.[16] We also consider information provided by Powercor, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions
- consider our total revenue allowance against section 16 of the NEL, including the constituent components and the interrelationships.

Table 3 shows our preliminary decision on Powercor's revenues and the building block components.

Table 3 AER's preliminary decision on Powercor's revenues ($ million, nominal)

	2016	2017	2018	2019	2020	Total
Return on capital	201.2	215.7	230.8	246.3	261.1	1155.1
Regulatory depreciation[a]	102.3	89.6	96.6	105.8	108.9	503.2
Operating expenditure	228.6	238.5	250.6	262.6	275.6	1255.9
Revenue adjustments[b]	4.2	-2.7	3.3	11.5	0.7	16.9
Corporate tax allowance	37.6	33.2	30.7	33.0	32.6	167.0
Annual revenue requirement (unsmoothed)	573.8	574.2	612.0	659.2	678.8	3098.0
X factor[c]	7.96%	7.96%	–0.75%	–0.75%	–0.75%	n/a
Annual expected revenue (smoothed)	**621.8**	**586.6**	**605.8**	**625.6**	**646.0**	**3085.8**

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Revenue adjustments include efficiency benefit sharing scheme carry-overs, forecast DMIA and 2010 S-factor scheme close out.

(c) The X factors from 2017 to 2020 will be revised to reflect the annual return on debt update.

3.1 Regulatory asset base

The RAB is the value of Powercor's assets used to provide distribution network services. It is the value on which Powercor earns a return on capital, and a depreciation allowance (return of capital). We assess Powercor's proposed opening value for the RAB for each year of the 2016–20 regulatory control period.[17]

Our preliminary decision is to set Powercor's opening RAB at $3344.4 ($ nominal) as at 1 January 2016. This is because we have amended Powercor's proposal to correct

[16] www.aer.gov.au/Better-regulation.

[17] NER, cll. 6.5.1 and S6.2.

a number of input errors to the model used by Powercor to roll forward the RAB. These amendments include:

- correcting the annual actual inflation rates for RAB indexation
- amending the proposed approach to the indexation adjustment required in the RAB
- adjusting allowed equity raising costs to the correct dollar terms.

These amendments reduced the opening RAB as at 1 January 2016 by $18.4 million (or 0.5 per cent) compared to Powercor's proposed opening RAB of $3362.9 million ($ nominal) at 1 January 2016.[18]

To determine the opening RAB as at 1 January 2016, we have rolled forward the RAB over the 2011–15 regulatory control period to determine a closing RAB value at 31 December 2015. This roll forward includes an adjustment at the end of the 2011–15 regulatory control period to account for the difference between actual 2010 capex and the estimate approved at the 2011–15 determination.[19]

Tables 4 and 5 set out our preliminary decision on the roll forward of Powercor's RAB for the 2011–15 regulatory control period and the forecast RAB for Powercor during the 2016–20 regulatory control period respectively.

Table 4 AER's preliminary decision on Powercor's RAB for the 2011–15 regulatory control period ($ million, nominal)

	2011	2012	2013	2014	2015[a]
Opening RAB	2212.8	2415.0	2600.1	2815.6	3073.1
Capital expenditure[b]	243.6	268.9	302.3	348.0	375.7
Inflation indexation on opening RAB	77.9	48.4	56.2	65.0	70.9
Less: straight-line depreciation	119.3	132.2	143.0	155.5	171.6
Closing RAB	2415.0	2600.1	2815.6	3073.1	3348.1
Difference between estimated and actual capex in 2010					–18.7
Return on difference for 2010 capex					–10.5
Six month CPI adjustment					25.5
Closing RAB as at 31 December 2015					**3344.4**

Source: AER analysis.

(a) Based on estimated capex. We will update the RAB roll forward in the substitute decision.

(b) Net of disposals and capital contributions, and adjusted for CPI.

[18] Powercor, *Regulatory proposal*, April 2015, p. 148, Table 12.1.

[19] The end of period adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2011–15 determination.

Table 5 AER's preliminary decision on Powercor's RAB for the 2016–20 regulatory control period ($ million, nominal)

	2016	2017	2018	2019	2020
Opening RAB	3344.4	3585.0	3836.4	4093.4	4340.6
Capital expenditure[a]	342.8	341.0	353.5	353.0	374.1
Inflation indexation on opening RAB	83.6	89.6	95.9	102.3	108.5
Less: Straight-line depreciation	185.9	179.2	192.5	208.1	217.4
Closing RAB	3585.0	3836.4	4093.4	4340.6	4605.8

Source: AER analysis.

(a) Net of forecast disposals and capital contributions.

We determine a forecast closing RAB value at 31 December 2020 of $4605.8 million ($ nominal). This is $480.5 million (or 9.4 per cent) lower than the amount of $5086.3 million ($ nominal) Powercor proposed. Our preliminary decision on the forecast closing RAB reflects the amended opening RAB as at 1 January 2016, and our preliminary decisions on forecast capex (attachment 6), forecast regulatory depreciation (attachment 5) and forecast inflation (attachment 3).

We accept Powercor's proposal that a forecast depreciation approach is to be used to establish the opening RAB at the commencement of the 2021–25 regulatory control period.[20]

Details of our preliminary decision on the value of the RAB are set out in attachment 2.

3.2 Rate of return (return on capital)

The return on capital provides a distributor with revenue to service the interest on its loans and to give a return on equity to shareholders. This building block is calculated as a product of the rate of return and the value of the RAB. [21]

The NER sets out that the allowed rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services.[22] The NER refers to this requirement as the allowed rate of return objective.

[20] NER, cl. 6.12.1(18); Powercor, *Regulatory proposal*, April 2015, p. 193.

[21] NER, cl. 6.5.2(a).

[22] NER, cl. 6.5.2(b).

We have determined an allowed rate of return of 6.02 per cent (nominal vanilla[23]), subject to annually updating cost of debt. We have not accepted Powercor's proposed 7.20 per cent return.[24] In accordance with the Rate of Return Guideline, we will update the rate of return annually, consistent with Powercor's proposal and our approach to return on debt.[25] Table 6 sets out the parameters we have used to determine the rate of return.

Table 6 AER's preliminary decision on Powercor's rate of return (nominal)

	AER previous decision (2011–15)	Powercor proposal (2016)[(a)]	AER preliminary decision (2016)	Return over 2016–20 regulatory control period
Return on equity (nominal post–tax)	10.28%	9.9%	7.3%	Remains constant (7.3%)
Return on debt (nominal pre–tax)	8.97%	5.39%	5.16%	Updated annually
Gearing	60%	60%	60%	Remains constant (60%)
Nominal vanilla WACC	9.49%	7.20%	6.02%	Updated annually as return on debt is updated
Forecast inflation	2.57%	2.60%	2.50%	Remains constant (2.50%)

Source: AER analysis; Powercor, *Regulatory proposal,* April 2015; AER, *Final decision: Victorian electricity distribution network service providers, Distribution determination 2011–15, October* 2010. The Australian Competition Tribunal, in *Application by United Energy Distribution Pte Ltd (No 2) [2012] ACompT 8 (5 April 2012).*

(a) Powercor's, Regulatory proposal uses values derived from the placeholder averaging periods for risk free rate and rate on debt in its revised proposal.

Our approach

All NER requirements relating to the rate of return are subject to the overall rate of return achieving the allowed rate of return objective.[26] The NER recognises that there may be several plausible answers that could achieve the allowed rate of return

[23] The nominal vanilla WACC combines a post-tax return on equity and a pre-tax return on debt, for consistency with other building blocks.

[24] Powercor, *Regulatory proposal*, April 2015, p. 248.

[25] NER, cl. 6.5.2(i)(2); Powercor, *Regulatory proposal*, April 2015, p. 202.

[26] NER, cl. 6.5.2(b).

objective.[27] We agree with stakeholders that predictability of outcomes in rate of return issues consistent with prevailing market conditions could materially benefit the long term interests of consumers. [28]

We developed our approach prior to the submission of this regulatory proposal, as required by the rate of return framework in the NER. In December 2013, we published the Rate of Return Guideline,[29] as contemplated by the NER. The Guideline was developed through extensive consultation in 2013.

Return on debt

In our previous regulatory decisions, we used an on-the-day approach to determine the return on debt.[30] This is the approach that many Australian regulators continue to use.

However, for this preliminary decision as with all our other decisions, we have determined a return on debt estimate that gradually transitions from an on-the-day approach to a trailing average approach.[31] This is consistent with the approach most stakeholders supported during the Guideline development process. In its regulatory proposal, Powercor proposed a different hybrid approach to ours.[32]

Return on equity

Powercor has departed from the Rate of Return Guideline in proposing a return on equity of 9.9 per cent.[33] Our approach involves considering all the information before us, through a six step process as set out in the Guideline (foundation model approach). This includes detailed consideration of a number of financial models for determining the return on equity.[34] Considering all of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective.

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27 AEMC, *Rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012: National gas amendment (Price and revenue regulation of gas services) Rule 2012*, 29 November 2012, p. 67 (AEMC, *Final rule change determination*, November 2012); AEMC, *Final rule change determination*, November 2012, p. iv, AEMC, *Final rule change determination*, November 2012, p. 38; The High Court of NZ stated: 'In determining WACC, precision is therefore an elusive and perhaps non-existent quality. Setting WACC is, we suggest, more of an art than a science. The use of WACC, in conjunction with RAB values, to set prices and revenue in price-quality regulation gives significance to WACC estimates that may not exist outside this context.' *Wellington International Airport Ltd & Others v Commerce Commission* [2013] NZHC 3289, para. 1189.

28 ENA, *Response to the Draft Rate of Return Guideline of the AER*, 11 October 2013, p. 1; AER, *Better regulation: Explanatory statement Rate of Return Guideline, Appendices*, December 2013, Appendix I, Table I.4, pp.185–186.

29 NER, cl. 6.5.2(m).

30 This involved determining the return on debt by reference to the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the 2016−20 regulatory control period.

31 In broad terms, this means that over the longer term the return on debt for any year will represent the average return on debt over the previous ten years.

32 Powercor, *Regulatory proposal*, April 2015, p. 241.

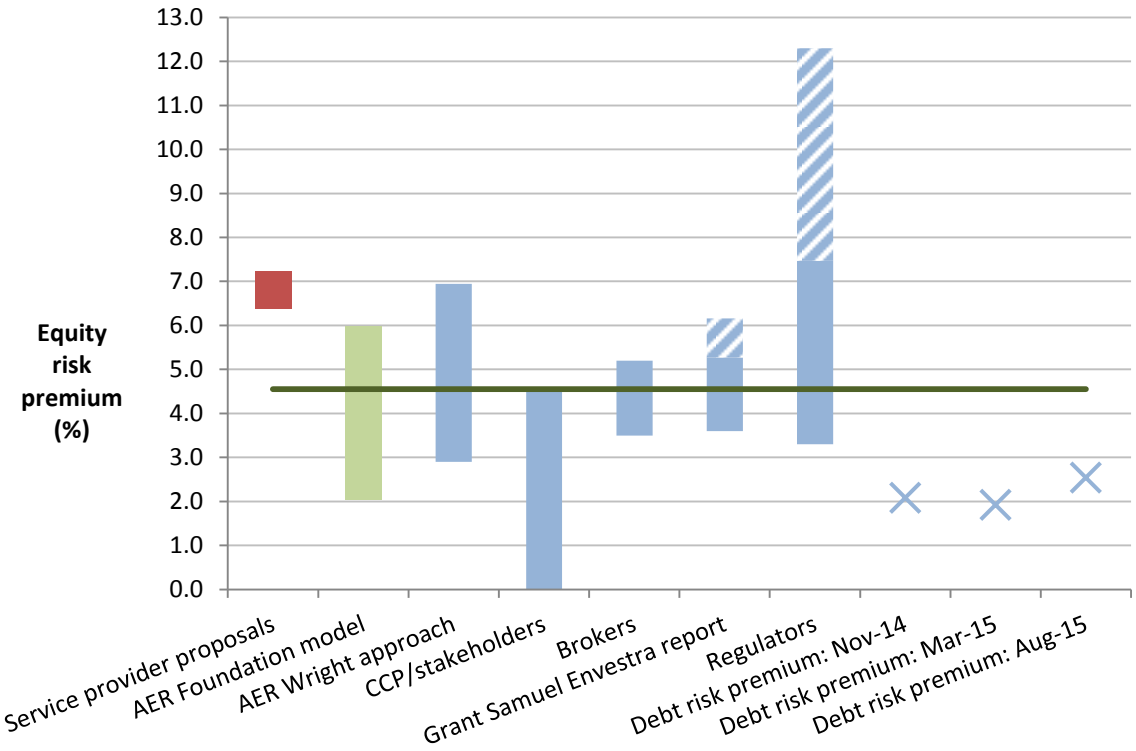
33 Powercor, *Regulatory proposal*, April 2015, p. 233.

34 NER, cl. 6.5.2(e)(1).

We consider that the Sharpe–Lintner capital asset pricing model (SLCAPM) is the superior financial model in terms of estimating expected equity returns. We have therefore adopted this model as our foundation model. The evidence before us indicates that on balance employing our foundation model approach and using the SLCAPM as the foundation model is expected to lead to a rate of return that achieves the allowed rate of return objective.[35]

We also evaluated our point estimate from the SLCAPM against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at any given time.[36] Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent which is within range of other information available to inform the return on equity (see figure 6). A detailed explanation of our findings on return on equity and this figure can be found in the attachment 3: Rate of return.

Figure 6 Other information comparisons with the AER allowed ERP



Source: AER analysis and various submissions and reports.

[35] McKenzie & Partington, *Part A: Return on equity, Report to the AER*, October 2014, p. 13; John Handley, *Advice on return on equity, Report prepared for the AER*, October 2014, p. 3.

[36] Our task is to determine the efficient financing costs commensurate with the risk of providing regulated network service by an efficient benchmark entity (allowed rate of return objective). Risks in this context are those which are compensated via the return on equity (systematic risks).

Notes: The AER foundation model equity risk premium (ERP) range uses the range and point estimate for MRP and equity beta as set out in step three. The calculation of the Wright approach, debt premium, brokers, and other regulators ranges is outlined in Appendices E.1, E.2, E.4, and E.5 respectively.

Grant Samuel's final WACC range included an uplift above an initial SLCAPM range. The lower bound of the Grant Samuel range shown above excludes the uplift while the upper bound includes the uplift and is on the basis that it is an uplift to return on equity. Grant Samuel made no explicit allowance for the impact of Australia's dividend imputation system. We are uncertain as to the extent of any dividend imputation adjustment that should be applied to estimates from other market practitioners. Accordingly, the upper bound of the range shown above includes an adjustment for dividend imputation, while the lower bound does not. The upper shaded portion of the range includes the entirety of the uplift on return on equity and a full dividend imputation adjustment.

The shaded portion of the other regulators range represents the impact of rail decisions on the range. We consider rail networks are unlikely to be comparable to the benchmark efficient entity.

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary decisions in October-December 2015. Equity risk premiums were calculated as the proposed return on equity less the risk free rate utilised in the service provider's proposed estimation approach.

The CCP/stakeholder range is based on submissions made (not including service providers) in relation to our final or preliminary decisions in October-December 2015. The lower bound is based on the Alliance of Electricity Consumers submission on Energex and Ergon Energy revised proposals. The upper bound is based on Origin Energy's submission on the preliminary decision for SA Power Networks.

3.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[37] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the NER requires that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.[38] That is, the revenue granted to a service provider to cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

Our preliminary decision is to adopt a value of imputation credits of 0.4. This differs from Powercor's proposed value of imputation credits of 0.25.[39]

Although we have broadly maintained the approach to determining the value of imputation credits set out in the Rate of Return Guideline, we have re-examined the

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37 *Income Tax Assessment Act 1997*, parts 3–6.

38 NER, cll. 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3.

39 Powercor, *Regulatory proposal*. April 2015, p. 249.

relevant evidence and estimates. This re-examination, and new evidence and advice considered for the first time since the Guideline, led us to depart from the value of 0.5 in the Guideline. Most notably, our updated consideration of the relevant advice and evidence led us to generally lower estimates of the 'utilisation rate' from the 0.7 estimate of the Guideline. Estimating the value of imputation credits is a complex and somewhat imprecise task. There is no consensus among experts on the appropriate value or estimation techniques to use.

Consistent with the relevant academic literature, we estimate the value of imputation credits as the product of the distribution rate and the utilisation rate. While there is a widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate and there is a range of evidence relevant to the utilisation rate. This includes:

- the proportion of Australian equity held by domestic investors (the 'equity ownership approach').
- the reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics').
- implied market value studies—there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits.

In estimating the utilisation rate, we place:

- significant reliance upon the equity ownership approach
- some reliance upon tax statistics
- less reliance upon implied market value studies.

Overall, the evidence on the distribution rate and the utilisation rate suggests that a reasonable estimate of the value of imputation credits is within the range 0.3 to 0.5. From within this range, we choose a value of 0.4. This is because:

- the equity ownership approach, on which we have placed the most reliance, suggests a value between 0.40 and 0.47 when applied to all equity and between 0.29 and 0.42 when applied to only listed equity. Therefore, the overlap of the evidence from the equity ownership approach suggests a value between 0.40 and 0.42.
- the evidence from tax statistics suggests the value could be lower than 0.4. Therefore, with regard to this evidence and the less reliance we place on it, we choose a value at the lower end of the range suggested by the overlap of evidence from the equity ownership approach (that is, 0.4).
- an estimate of 0.4 is reasonable in light of both higher and lower estimates from implied market value studies and the lesser degree of reliance we place on these studies. The service providers submitted evidence to support placing more reliance on SFG's dividend drop off study relative to other implied market value studies. However, we consider that neither the difference from 0.4 of the estimate from this

study (0.31) nor any increased reliance we might place on it relative to other implied market value studies are sufficient to warrant an estimate lower than 0.4.

3.4 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). We are required to decide on whether to approve the depreciation schedules submitted by Powercor.[40] In doing so, we make a determination on the indexation of the RAB and depreciation building blocks for Powercor's 2016−20 regulatory control period.

Our preliminary decision is to determine a regulatory depreciation allowance of $503.2 million ($ nominal) for Powercor. This amount represents a decrease of $0.3 million (or 0.1 per cent) of the $503.5 million ($ nominal) Powercor proposed for the 2016–20 regulatory control period.[41] In coming to this decision:

- We accept Powercor's proposed asset classes and its straight-line depreciation method used to calculate the regulatory depreciation allowance. However, we have included a new 'Land' asset class that will consist of any land related forecast capex.[42]
- We accept Powercor's proposed standard asset lives for its existing asset classes, with the exception of the 'VBRC' asset class. For the 'VBRC' asset class, we consider that the standard asset life should equal the standard asset life for the 'Distribution system assets' class, instead of the remaining asset life.
- We do not accept Powercor's proposed average depreciation method to calculate remaining asset lives at 1 January 2016. However, consistent with Powercor's submission to the AER's issues paper, we have applied a year-by-year tracking approach to determine the depreciation for existing assets.[43]
- We accept Powercor's proposal to accelerate the depreciation of two particular asset sub-classes, 'Old SWER ACRs' and 'Supervisory cables'. The changed depreciation schedules reflect new regulatory requirements (Old SWER ACRs) or economically justified replacement (Supervisory cables) that have changed the economic life of the assets.[44]
- We made determinations on other components of Powercor's proposal that also affect the forecast regulatory depreciation allowance—for example, the forecast capex (attachment 6), the opening RAB value (attachment 2), and forecast inflation (attachment 3).[45]

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40 NER, cl. 6.12.1(8).

41 Powercor, *Regulatory proposal 2016–20*, April 2015, pp. 256.

42 NER, cl. 6.5.5(b)(1).

43 CitiPower and Powercor, *Submission in response to the issues paper, Depreciation*, 13 July 2015.

44 NER, cl. 6.5.5(b)(1).

45 NER, cl. 6.5.5(a)(1).

Table 7 sets out our preliminary decision on Powercor's depreciation allowance for the 2016–20 regulatory control period.

Table 7 AER's preliminary decision on Powercor's depreciation allowance for the 2016−20 regulatory control period ($ million, nominal)

	2016	2017	2017–18	2018–19	2019–20	Total
Straight-line depreciation	185.9	179.2	192.5	208.1	217.4	983.2
Less: inflation indexation on opening RAB	83.6	89.6	95.9	102.3	108.5	480.0
Regulatory depreciation	**102.3**	**89.6**	**96.6**	**105.8**	**108.9**	**503.2**

Source: AER analysis.

Details of our preliminary decision on the regulatory depreciation allowance are set out in attachment 5.

3.5 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of network services. The return on and return of forecast capex for standard control services are two of the building blocks we use to determine a service provider's total revenue requirement.

We estimate total net capex of $1610.4 million ($2015) for Powercor's 2016−20 regulatory control period—which is a 19.7 per cent reduction to Powercor's forecast capex of $2006.3 million ($2015). We are satisfied our substitute estimate of Powercor's total capex reasonably reflects the capex criteria. Table 8 shows our preliminary capex decision compared to Powercor's proposal.

Table 8 AER preliminary decision on total net capex ($million 2015)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Powercor's proposal	392.3	399.3	406.4	397.8	410.5	2,006.3
AER preliminary decision	320.4	321.3	324.9	316.6	327.2	1,610.4
Difference	-71.9	-78.0	-81.5	-81.2	-83.3	-395.9
Percentage difference (%)	-18.3	-19.5	-20.1	-20.4	-20.3	-19.7

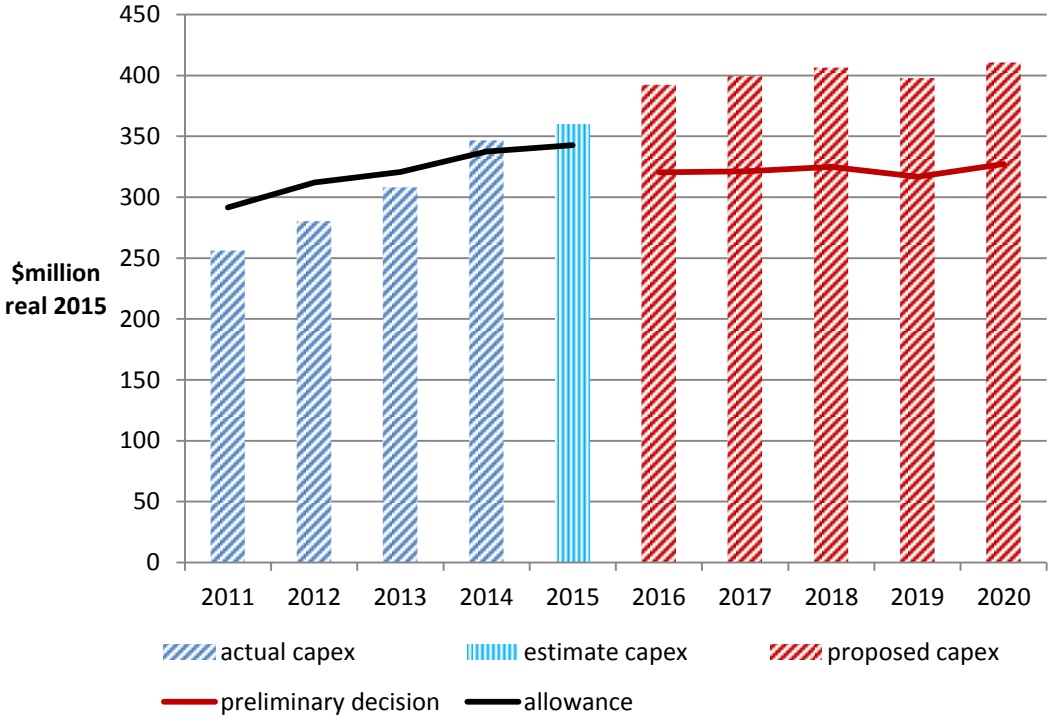
Source: Powercor, *Regulatory proposal 2016–2020*, April 2015, pp. 101–102; AER analysis.

Note: Numbers may not add up due to rounding.

Note: The figures above do not include equity raising costs. For our assessment of equity raising costs, see attachment 3.

Figure 7 shows our preliminary capex decision compared to Powercor's proposal, its past allowances and past actual expenditure.

Figure 7 Powercor's total actual and forecast capex 2011–2020



We examined Powercor's forecasting methodology, key assumptions and past capex performance. Attachment 6 sets out our detailed reasons for our preliminary decision on Powercor's total forecast capex.

The key areas of difference between our substitute capex estimate and Powercor's proposal are:[46]

- Our alternative estimate of total capex includes $609 million ($2015) for repex.[47] This is 16 per cent lower than Powercor's repex proposal of $722 million. Our repex modelling estimates a lower amount of "business as usual" repex is necessary compared to Powercor's forecast for the modelled categories of repex. We also do not accept Powercor's proposed increase to repex for pole top structures.
- Our alternative estimate of total capex includes $241.6 million ($2015) for augex. This is 33 per cent lower than Powercor's augex proposal of $362.3 million ($2015). Our estimate is lower because we consider Powercor's demand forecast is overstated. Using a realistic demand forecast, we consider less capex is required to augment Powercor's network than it had forecast, including for its high voltage feeders and a new Torquay zone substation. In addition, we consider that Powercor's proposed capex for voltage regulators is not necessary

[46] We obtained these figures from Powercor's RIN. Our assessment used information from information subsequently provided by Powercor.

[47] Excluding overheads.

- We estimate $724.6 million ($2015) for connections.[48] Our connections capex estimate is lower because we consider Powercor's forecasting methodology overstates the amount of high volume connection activities required in the 2016–20 period.
- Our estimate of connections capex includes customer contributions of $358.9 million ($2015). This is higher than Powercor's forecast of $316.1 million ($2015). Our customer contribution estimate is higher because we are not satisfied Powercor's sampling approach to generate its contribution rate is reflective of the projects included in its total connections capex forecast.
- We estimate $226.4 million ($2015) for Powercor's non–network capex. This is 86 per cent of Powercor's non–network capex forecast of $262.1 million ($2015). As part of our estimate, we accept Powercor's forecasts for a range of non–network capex components. Our total non–network capex estimate is lower than Powercor's forecast because we consider its proposed IT program is not prudent and efficient. We include in our estimate of non–network capex a lower forecast for IT expenditure.
- We do not accept Powercor's proposed capitalised overheads of $202.3 million ($2015). We have instead included in our substitute estimate of overall total capex an amount of $197.7 million ($2015) for capitalised overheads. This reduction in forecast overheads reflects our direct capex forecast that is expected to attract overhead expenditure.
- Our total capex allowance also includes expenditure from new safety obligations arising as a result of the recommendations of the 2009 Victorian Bushfire Royal Commission.

3.6 Operating expenditure

Operating expenditure (opex) is non-capital expenditure incurred in the provision of distribution network services. It includes labour and other non-capital costs that Powercor is likely to require to operate and maintain its network during the 2016–20 regulatory control period.

Powercor forecast total opex of $1330.7 million ($2015) over the 2016–20 regulatory control period. Our preliminary decision is we are not satisfied Powercor's forecast opex reasonably reflects the opex criteria. Where we find that a distributors' forecast opex does not reasonably reflect the opex criteria, the NER instruct us to not accept it and replace it with a forecast that we are satisfied reasonably reflects the opex criteria.

Attachment 7 sets out our detailed reasons for our preliminary decision on Powercor's total forecast opex. We compare our estimate with Powercor's proposal in table 9.

[48] Gross capex, including customer contributions.

Table 9 AER preliminary decision on total opex ($ million, 2015)

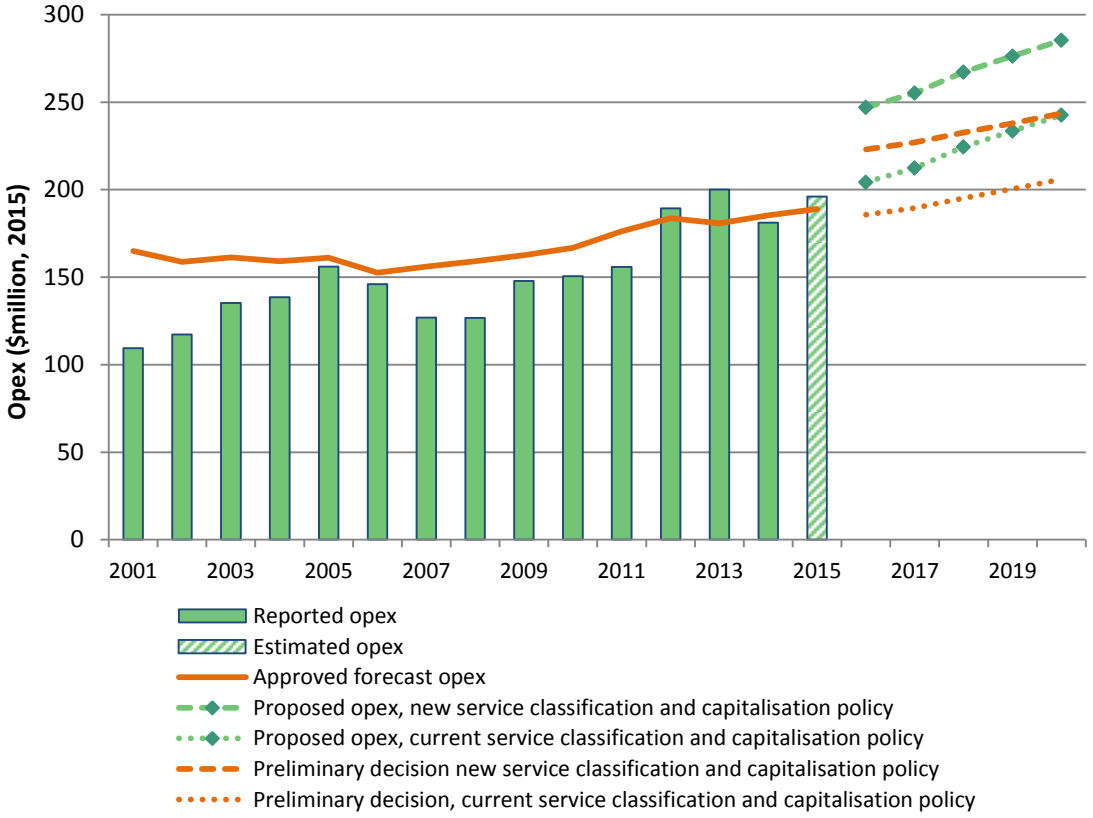
Year ending 30 June	2016	2017	2018	2019	2020	Total
Powercor's proposal	246.9	255.2	267.1	276.2	285.3	**1330.7**
AER preliminary decision	223.0	227.0	232.7	237.9	243.6	**1164.2**
Difference	**–23.9**	**–28.2**	**–34.4**	**–38.3**	**–41.7**	**–166.5**

Source: AER analysis.

Note: Includes debt raising costs. Excludes DMIA.

Figure 8 shows our preliminary decision compared to Powercor's proposal, its past allowances and past actual expenditure. Notably, Powercor will change its capitalisation policy in 2016. This causes a step increase in forecast opex, which is offset by a corresponding reduction in capex. We have agreed to this change. Also, Powercor included significant opex for 2016–20 for smart meters that was not previously classified as standard control services opex. We have allocated these costs to alternative control services rather than standard control services—therefore our preliminary decision is on the basis of this cost allocation for advanced metering infrastructure (AMI) opex.

Figure 8 AER preliminary decision compared to Powercor's past and proposed opex ($million, 2015)



Source: Powercor, Regulatory accounts 2011 to 2014; Powercor, Economic benchmarking - Regulatory Information Notice response 2006 to 2013; AER analysis.

We have used Powercor's reported opex for 2014 as the basis for forecasting total opex. The main difference between our forecast opex and Powercor's proposal reflects our views on:

- the rate of change
- the allocation of advanced metering infrastructure (AMI) related opex.

3.6.1 Rate of change

The difference between our forecast of the rate of change and Powercor's proposal reflects our views on price growth and output growth:

- using information from our expert consultants, we have forecast a lower labour price growth than Powercor and we have adopted different opex price weights
- our approach to forecasting output growth used information from Economic Insights, Powercor's reset RIN and AEMO, which produced a lower forecast than that proposed by Powercor.

3.6.2 Advanced metering infrastructure

We have not included opex for advanced metering infrastructure (AMI) expenditure in our forecast. During the 2011–15 regulatory control period, incremental costs associated with implementing smart meters were regulated under the AMI Order in Council (OIC). This included costs associated with new or upgraded IT systems.

With the expiry of the AMI OIC at 31 December 2016, opex associated with AMI will be regulated under the NER and allocated between standard control services and alternative control services. Given the rollout of smart meters is largely complete, this opex is for the business-as-usual costs of maintaining the metering infrastructure. Until we issue new Distribution Ring Fencing Guidelines that will set out how metering costs should be treated, we consider all costs formerly regulated under the AMI OIC should be allocated to alternative control services. This is similar to the historical approach where AMI costs were recovered separately to most distribution network costs. We consider this approach will assist in promoting transparency around trends in AMI and standard control expenditure.

3.7 Corporate income tax

The NER requires us to make a decision on the estimated cost of corporate income tax for Powercor's 2016–20 regulatory control period.[49] The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for Powercor over the 2016–20 regulatory control period. It enables Powercor to recover the costs associated with the estimated corporate income tax payable during that period.

[49] NER, cl. 6.4.3(a)(4).

Our preliminary decision on the estimated cost of corporate income tax is $167.0 million ($ nominal) for Powercor over the 2016–20 regulatory control period. This is instead of Powercor's proposed cost of corporate income tax allowance of $244.8 million ($ nominal). Our preliminary decision represents a reduction of $77.8 million (or 31.8 per cent) from Powercor's proposal. Table 10 sets out our preliminary decision on the estimated cost of corporate income tax allowance for Powercor.

Table 10 AER's preliminary decision on Powercor's cost of corporate income tax allowance for the 2016–20 regulatory control period ($ million, nominal)

	2016	2017	2018	2019	2020	Total
Tax payable	62.6	55.3	51.1	55.1	54.3	278.3
Less: value of imputation credits	25.0	22.1	20.4	22.0	21.7	111.3
Corporate income tax allowance	**37.6**	**33.2**	**30.7**	**33.0**	**32.6**	**167.0**

Source: AER analysis.

Our preliminary decision reflects our amendments to some of Powercor's proposed inputs for forecasting the cost of corporate income tax such as the opening tax asset base and the remaining tax asset lives. It also reflects our preliminary decision on the value of imputation credits—gamma—(attachment 4). Changes to the building block costs also affect revenues, which in turn impacts the tax calculation. The changes affecting revenues are discussed in attachment 1.

Details of our preliminary decision on the corporate income tax allowance are set out in attachment 8.

4 Service classification, control mechanisms and incentive schemes

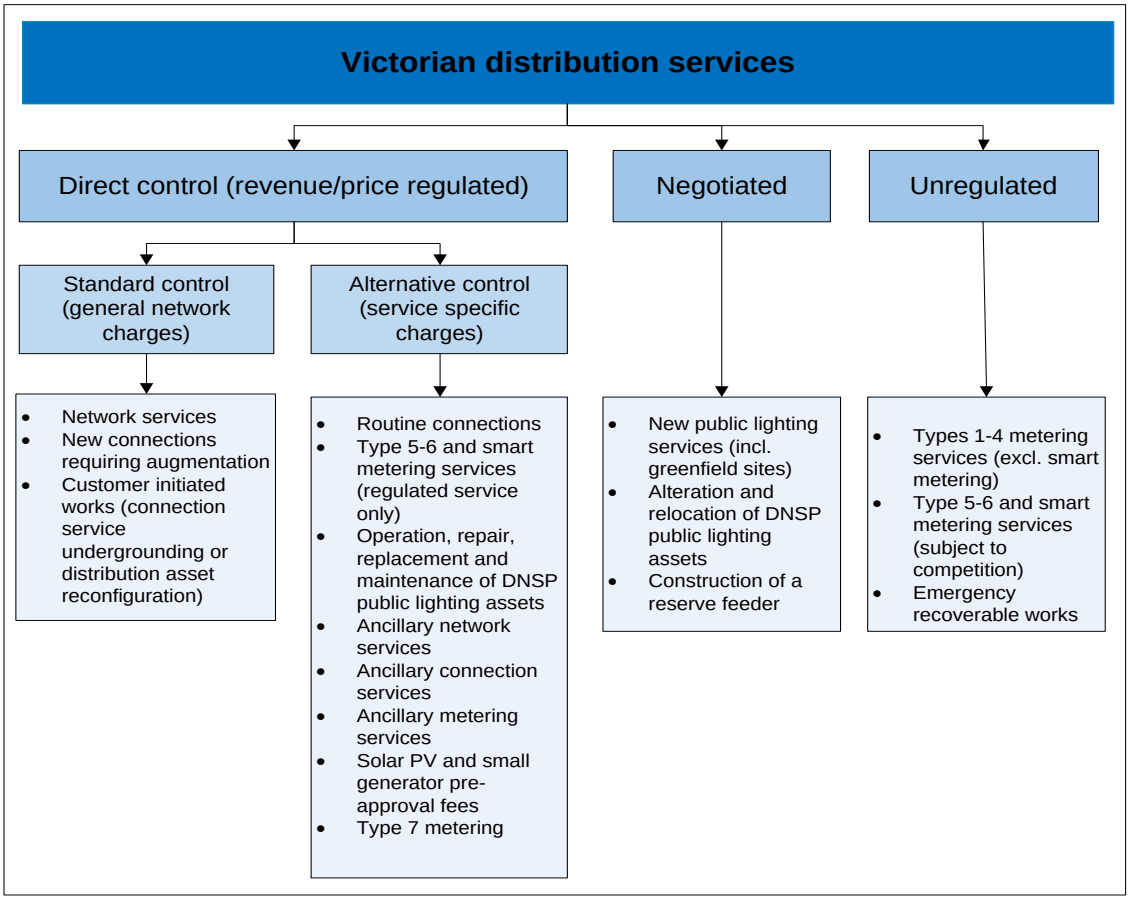
A range of factors, in addition to the building blocks, affect Powercor's revenues. These include service classification, the control mechanism and our approach to services charged to individual consumers and incentive schemes to promote efficiency. This section sets out our approach to these issues.

4.1 Classification of services and control mechanisms

Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our preliminary decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

Figure 9 summarises our preliminary determination on service classifications for the 2016–20 regulatory control period.

Figure 9 AER preliminary decision on 2016–20 service classifications for Powercor



Source: AER.

Consistent with our final framework and approach (F&A),[50] Powercor will be subject to a 'revenue cap' form of control for standard control services over the next regulatory control period. The control mechanism (which describes how the revenues will vary from year to year) is discussed in attachments 14 and 16. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the revenue cap.

4.2 Alternative control services

Alternative control services do not form part of Powercor's revenue cap. Rather, the prices of these services are generally set individually. Our preliminary determination for all services other than metering is to maintain the approach adopted in our F&A, that the form of control mechanism to apply to Powercor's alternative control services will be price caps. As per past regulatory practice, Powercor must demonstrate compliance with the control mechanism through an annual pricing proposal.

We have set charges for fee based and quoted services that reflect the costs incurred by Powercor to provide these services. Powercor only earns revenues on these activities where they are specifically requested by individual customers. Further details are in attachment 16.

The charges for public lighting have been set on the same basis as the 2011–15 regulatory control period. That is, with Powercor operating, maintaining and replacing luminaires it owns on behalf of municipal councils in its distribution area. It does this in accordance with both our preliminary determination and the Public Lighting Code. Attachment 16 set out that there has been an increase in charges as a result of higher operating expenditures, mostly associated with the growth in labour costs.

The Advanced Metering Infrastructure rollout that commenced in 2009 under an Order in Council (the Order) is now largely completed. In the 2016–20 regulatory control period, metering in Victoria is entering a "business-as-usual" phase.

For metering services, we have set charges that recover the operating and capital expenditures associated with the ongoing provision of meters to customers from 2016. This means that we regulate metering services under the NEL and NER, subject to certain modifications set out in the Order. Those modifications contain the requirement for us to set meter restoration and exit fees which this determination includes—see attachment 16.

A revenue cap will operate for metering services during the 2016–20 regulatory control period. The completion of the rollout means Powercor needs less revenue to provide

[50] AER, *Final framework and approach for the Victorian Electricity Distributors – Regulatory control period commencing 1 January 2016*, October 2014.

the services and as a consequence meter charges have fallen between 2015 and 2016 in particular.

Powercor has proposed that some of the costs associated with the provision of Advanced Metering Infrastructure (AMI) be classified under standard control services. We do not agree. All costs associated with AMI are classified under alternative control services. As a result, some of the difference between Powercor's forecast opex and our alternative forecast is simply as a result of reclassifying costs from standard control services to alternative control services.

4.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to Powercor are:

- The efficiency benefit sharing scheme (EBSS)
- The capital expenditure sharing scheme (CESS)
- The service target performance incentive scheme (STPIS)
- The demand management incentive scheme (DMIS)
- The f-factor scheme.

Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced (approximately 30 per cent) and constant. They are also balanced with the incentives under our service target performance incentive scheme. This encourages businesses to make efficient decisions on when and what type of expenditure to incur, in order to meet service reliability targets.

4.3.1 Efficiency benefit sharing scheme

The EBSS provides an additional incentive for service providers to pursue efficiency improvements in opex.

As opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period (step changes provide for increases where this is not the case). Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period to forecast opex for the next regulatory control period. We call this the 'revealed cost approach'.

To encourage a distributor to become more efficient during the regulatory control period it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. This is supplemented by the EBSS which allows the distributor to retain efficiency savings and efficiency losses for a longer period of time. In total these rewards and penalties work together to provide a continuous incentive for a service provider to pursue efficiency gains over the regulatory control period. The combined effect of our revealed cost forecasting

approach and the EBSS is that opex efficiency savings or losses are shared approximately 30:70 between the network businesses and consumers. For example, for a one dollar saving in opex the network business gets 30 cents of the benefit while consumers get 70 cents of the benefit.

The EBSS also discourages a distributor from incurring opex in the expected base year in order to receive a higher opex allowance in the following regulatory control period.[51]

Our preliminary decision for the EBSS carryover amounts from the application of the EBSS in the 2011–15 regulatory control period is outlined in table 11. The difference between our calculations and Powercor's proposal is mostly attributable to using a different formula to calculate Powercor's carryover amounts for 2011.

Table 11 AER's preliminary decision on Powercor's EBSS carryover amounts ($ million, 2015)

	2016	2017	2018	2019	2020	Total
Powercor's proposed carryover	11.0	-1.1	4.1	8.2	-	22.1
Preliminary decision	12.5	–3.2	2.5	9.8	-	21.6

Source: AER analysis; Powercor, *Regulatory proposal*, April 2015, p. 249.

Our preliminary decision is to apply version two of the EBSS to Powercor in the 2016–20 regulatory control period.[52] Our preliminary decision on the EBSS is discussed in Attachment 9.

4.3.2 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides a network service provider with the same reward for an efficiency saving and same penalty for an efficiency loss regardless of which year they make the saving or loss. Consumers benefit from improved efficiency through lower regulated prices.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

For capex, the sharing of underspends and overspends happens at the end of each regulatory control period when we update a network service provider's RAB to include

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[51] These concepts are explained more fully in the explanatory statement to the EBSS, AER, *Efficiency benefit sharing scheme for electricity network service providers - explanatory statement*, November 2013.

[52] AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

new capex. If a network service provider spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the service provider had spent the full amount of the capex forecast.

Our preliminary determination is to apply version 1 of the CESS, as set out the Capital Expenditure Incentives Guideline, to Powercor in the 2016–20 regulatory control period as Powercor proposed.[53] Attachment 10 sets out our reasons for our preliminary determination on CESS.

4.3.3 Service target performance incentive scheme (STPIS)

Consistent with our final F&A, our preliminary determination is to apply the service standards component (the s-factor) of our national STPIS to Powercor for the 2016–20 regulatory control period. We will not apply the guarantee service level component to Powercor as the existing Victorian jurisdictional arrangements will continue to apply.[54] Our preliminary decision is to set revenue at risk for Powercor at the range ± 5.0 per cent.

The national STPIS is intended to balance the incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing appropriate financial incentives to distributors to maintain and improve service performance (at the level where customers are willing to pay for these improvements).[55] Hence, the STPIS also provides an incentive for distributors to invest in further reliability improvements (via additional capex or opex) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate beyond the acceptable level valued by customers. Importantly, the distributor will only receive a financial reward after actual improvements are delivered to the customers.

Distributors can only retain their rewards for sustained and continuous improvements to the reliability of supply to customer. Once improvements are made, the benchmark performance targets will be tightened in future years.

In conjunction with the EBSS and CESS, the STPIS will ensure that:

- any additional investments to improve reliability are based on prudent economic decisions
- reductions in capex are achieved efficiently, rather than at the expense of service levels to customers.

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53 Powercor, *Regulatory Proposal, 2016-2020*, April 2015, p. 193.

54 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 96–97.

55 AER, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009. (AER, *Electricity distribution STPIS*, Nov 2009.

In setting the STPIS performance targets, we have considered both completed and planned reliability improvements expected to materially affect network reliability performance. By setting the performance targets in such a way, any incentive a distributor may have to reduce the capex at the expense of target service levels should be curtailed by the STPIS financial penalties.

Attachment 11 sets out our preliminary determination on Powercor's service component parameter values.

4.3.4 Demand management incentive scheme

The DMIS includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects.

Our preliminary decision is to continue Part A of the DMIS for Powercor in the 2016–20 regulatory control period (that is, the DMIA component). We will not apply Part B of the DMIS to Powercor for the 2016–2020 regulatory control period because we have decided to apply a revenue cap form of control. This is consistent with our proposed approach in our final Framework and Approach paper.[56]

The current innovation allowance amount of $0.6 million ($2015) per annum will continue in the 2016–20 regulatory control period.

Attachment 12 sets out our preliminary determination on Powercor's DMIS.

4.3.5 f-factor scheme

The f-factor is an incentive scheme to reduce the risk of fire starts due to electricity infrastructure and the risk of loss or damage caused by such fire starts. The current incentive framework of the scheme is to set the performance target based on a five year historical average and an incentive rate of $25 000 per fire start.

The f-factor scheme is prescribed by *f-factor scheme order 2011* (the Order) issued under the National Electricity (Victoria) Act 2005. The Order confers functions and powers on the AER to implement the f-factor.

As explained in the Framework and approach paper, the Department of State Development Business and Innovation advised that it intend to review the f-factor scheme in 2015 to determine how the incentive has performed in delivering efficient improvements to power line bushfire safety. Because of this, we will retain the current incentive framework for the purpose of this preliminary decision to set the target based on a five year historical average and an incentive rate of $25 000 per fire start. We will amend this scheme as appropriate to reflect any changes by the Victorian Government following the review.

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[56] AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p. 114.

Attachment 18 sets out our preliminary decision on the f-factor scheme.

5 Understanding the NEO

The NEO is the central feature of the regulatory framework. The NEO 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.[57]

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.[58] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[59]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[60] We have also considered the quality and reliability of services provided to consumers. For example, opex allowances have been set so Powercor may meet existing and new regulatory requirements. Repex allowances take into account the age and condition of assets. We have allowed sufficient augex and connections capex to cater for expected areas of growth. Our capex allowance is based on a contemporary estimate of the value of customer reliability. And the STPIS encourages maintenance, and indeed improvement of, service quality.

The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[61] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would.

For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[62] This could have significant longer term pricing implications for those consumers who continue to use network services.

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57 NEL, s. 7.

58 Hansard, *SA House of Assembly*, 9 February 2005, pp. 1451–1460.
Hansard, *SA House of Assembly*, 27 September 2007, pp. 963–972.
Hansard, *SA House of Assembly*, 26 September 2013, pp. 7171–7176.

59 Hansard, *SA House of Assembly*, 26 September 2013, p. 7173.

60 Hansard, *SA House of Assembly*, 9 February 2005, p. 1452.

61 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50.

62 NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[63] and could have adverse consequences for safety, security and reliability of the network.

The NEL also includes the revenue and pricing principles (RPP), [64] which support the NEO. As the NEL requires,[65] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> 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—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> - in any previous—
> - as the case requires, distribution determination or transmission determination; or
> - 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
> - in the Rules.
>
> 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

63 NEL, s. 7A(6).
64 NEL, s. 7A.
65 NEL, s. 16(2).

involved in providing the direct control network service to which that price or charge relates.

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.

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.

Consistent with Energy Ministers' views, we set revenue allowances to balance all elements of the NEO and consider each of the RPPs.[66] For example:

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that we should provide Powercor with a reasonable opportunity to recover at least efficient costs. (Refer to capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a network service provider in our assessment of Powercor's forecast capital expenditure and operating expenditure proposals. (Refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of Powercor's distribution system in our demand forecasting and augmentation determinations (Refer to capex attachment 6).
- Our application on the EBSS, CESS, STPIS and DMIS in this determination provides Powercor with effective incentives which we consider will promote economic efficiency with respect to the direct control services that Powercor provides throughout the regulatory control period. (Refer to attachments 9, 10, 11 and 12).
- We have determined Powercor's opening RAB taking into account the RAB adopted in the previous distribution determination. (Refer to attachment 2, regulatory asset base).
- The allowed rate of return objective reflects the revenue and pricing principle in s.7A(5). We have determined a rate of return that we consider will provide Powercor with a return commensurate with the regulatory and commercial risks involved in providing direct control services. (Refer to attachment 3, rate of return).
- Our financing determinations provide the distributor with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to attachment 3, rate of return).

[66] Hansard, *SA House of Assembly*, 27 September 2007, pp. 965. Hansard, *SA House of Assembly*, 26 September 2013, p. 7173.

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses, for example, our choice of equity beta. While it can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, the AER is also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the determination are each set too conservatively.[67] The legislative framework recognises the complexity of this task by providing the AER with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[68]

5.1 Achieving the NEO to the greatest degree

A distribution determination is a complex decision and must be considered as such. In most instances, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, chapter 6 of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several plausible point estimates.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. Where this is the case, our role is to

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[67] AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 52.

[68] NEL, s. 88.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* p. 8.

make an overall decision that we are satisfied contributes to the achievement of the NEO to the *greatest* degree.[69]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NEO, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree.

Also, in coming to this preliminary decision we have considered Powercor's regulatory proposal. We have examined each of the building block components of the proposal and the incentive mechanisms that would apply across the next regulatory control period. We have considered the submissions we received in regard to Powercor's proposal. We have conducted our own analysis and engaged expert consultant to help us better understand if and how Powercor's proposal contribute to the achievement the NEO. We have also considered how our constituent decisions relate to each other, the impact that particular constituent decisions have on other constituent components of our decision, and have described these interrelationships in this preliminary decision. We have undertaken an extensive and consultative regulatory review process to ensure we have canvassed stakeholder issues and made as much of this information publicly available as practicable. We have had regard to and weighed up all the information assembled before us in making this preliminary decision.

Therefore, we are satisfied that among the options before us, our preliminary decision on Powercor's distribution determination for the 2016–20 regulatory control period contributes to the achieving the NEO to the greatest degree.

5.1.1 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[70] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark

[69] NEL, s. 16(1)(d).

[70] SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013, p. 6.

efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the distributor's approach to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our preliminary decision. These considerations are explored in the relevant attachments.

6 Consultation

Stakeholder participation is important to informed decision making under the NEL and NER. It allows us to take a range of views into account when considering how a proposal or decision contributes to the NEO. Effective consultation and engagement provide confidence in our processes and are good regulatory practice.

We have undertaken extensive consultation in developing this preliminary decision. Also, the NER require us to take account of network businesses' consultation with their customers in our consideration of their proposals. This requirement is part of recent reforms that support consumer involvement in the regulatory process (section 6.2).

6.1 Our consultation process

In developing this preliminary decision we have considered views presented to us by all stakeholders. We also received advice from expert consultants and our Consumer Challenge Panel.

The NER sets out a process for both consultation on our decisions and publication of information that will inform those decisions. Under the transitional rules for this decision, we must:

- publish the regulatory proposals and any supporting material
- invite written submissions on the regulatory proposals
- hold a public forum on the regulatory proposals
- publish a preliminary determination and reasoning
- invite written submissions on the preliminary determination
- publish a final determination and reasoning.

In developing this preliminary decision, in addition to the above steps in the consultation process, we:

- published an issues paper
- published a consumer guide on this process and our assessment approach
- sought advice from the AER's Consumer Challenge Panel
- held meetings with the Victorian consultative group, which includes Victorian consumer representatives, among others
- held training sessions on the building block model for members of the Victorian consultative group and some other stakeholders
- held a workshop on demand management with members of the Victorian consultative group and the distribution businesses
- held a workshop on demand forecasts with AEMO and the distribution businesses

- held meetings with the distribution businesses on various elements of their regulatory proposals
- sought further information from the distribution businesses about the regulatory proposals when questions arose, including through information requests.

This process builds on the consultation we undertook with a broad range of stakeholders as part of the Better Regulation program. Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[71]

This gives us confidence the approaches set out in our various guidelines, which we have applied in this decision, will result in outcomes that will or are likely to contribute to the achievement of the NEO to the greatest degree. Our Better Regulation guidelines are available on our website[72] and include:

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline for Network Service Providers
- Shared Assets Guideline
- Confidentiality Guideline.

The guidelines provide businesses, investors and consumers predictability and transparency of our approach to regulation under the new rules.

6.2 Consumer engagement

Recent changes to the NER provide further support for consumer involvement in the regulatory process, and enable us to engage more productively with energy consumers and businesses.[73] Chapter 6 of the NER was amended to, among other things, require:

- distributors to submit an overview with their regulatory proposal which describes how they have engaged with consumers and sought to address any relevant concerns identified by that engagement[74]
- the AER to publish an issues paper after receiving the distributor's regulatory proposal.[75] The purpose of the issues paper is to assist consumer representative

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71 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

72 www.aer.gov.au/Better-regulation-reform-program.

73 AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*.

74 NER, cl. 6.8.2(c1)(2).

75 NER, cl. 6.9.3(b).

groups to focus on the key preliminary issues on which they should engage and comment[76]

- the AER, when determining capex and opex allowances, to have regard to the extent to which the forecast includes expenditure to address the concerns of consumers as identified by the distributor in the course of its engagement with the consumers.[77]

Powercor undertook its own engagement with consumers in developing its regulatory proposal. For example, Powercor held forums, focus groups and interviews, and sought feedback on a 'directions and priorities' consultation paper.[78]

Victorian Energy Consumer and User Alliance (VECUA) recognised that consumer engagement is a new space for distributors. VECUA provided some perspectives to assist us in our assessment of the distributors' claims, and the distributors to improve the effectiveness of their ongoing consumer engagement efforts.[79]

Specifically, VECUA submitted that the distributors need to have consumers more involved in their decision-making regarding options and preferred solutions, to provide consumers with more detailed information, and to better enable consumers to challenge the distributors through their participation. VECUA noted that a deeper level of consumer participation will result in revenue proposals that better reflect consumers' long term interests.[80]

Consumer Utilities Advocacy Centre (CUAC) submitted that while Powercor published regular information about its plans, CUAC found it difficult to arrange meetings with the business.[81]

We consider that Powercor has taken important initial steps to involving consumers in the regulatory process, although we note CUAC identified Powercor could be more accessible to consumer representatives.[82] VECUA and the Consumer Challenge Panel indicated there are further opportunities for Powercor to improve the way it objectively

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76 AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*.

77 NER, cll. 6.5.6(e)(5A) and 6.5.7(e)(5A).

78 CitiPower, Regulatory Proposal, April 2015, p. 58.

79 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 49.

80 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 51.

81 Consumer Utilities Advocacy Centre, *RE Victorian electricity distribution pricing review (EDPR), 2016 to 2020*, 13 July 2015.

82 Consumer Utilities Advocacy Centre, *RE Victorian electricity distribution pricing review (EDPR), 2016 to 2020*, 13 July 2015.

seeks consumer feedback.[83] [84] We expect Powercor to consider these submissions in developing its consumer engagement program going forward.

[83] Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, pp. 49–53; Consumer Challenge Panel – Sub panel 3, *Response to proposals from Victorian electricity distribution network service providers*, 5 August 2015, pp. 4–9.

[84] Further, the Ethnic Communities' Council of Victoria submitted that Victorian distribution businesses should engage more with culturally and linguistically diverse consumers—particularly those who may be disadvantaged by 'price-based mechanisms' to balance quality and service with operational costs (Submission to the Australian Energy Regulator Victoria Electricity Pricing Review, 15 July 2015, p. 6.). Similarly, CUAC submitted that Powercor's consideration of how to engage with low-income, vulnerable and culturally and linguistically diverse groups was not well developed (RE Victorian electricity distribution pricing review (EDPR), 2016 to 2020, 13 July 2015).

A Constituent decisions

Our preliminary distribution determination is predicated on the following decisions (constituent decisions):[85]

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In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to Powercor for the 2016–20 regulatory control period (listed by service group): • Standard control services include network services, connection services requiring augmentation, customer initiated works (connection service undergrounding or distribution asset reconfiguration) • Alternative control services include routine connections, type 5-6 and smart metering services (regulated service only), operation, repair, replacement and maintenance of public lighting assets, ancillary network services, ancillary connection services, ancillary metering services, solar PV and small generator pre-approval fees, type 7 metering • Negotiated distribution services include new public lighting services (incl. greenfield sites), alteration and relocation of DNSP public lighting assets, construction of a reserve feeder • Unregulated services include type 1 to 4 metering services (excl. smart metering), type 5-6 and smart metering services (subject to competition), emergency recoverable works. Attachment 13 of the preliminary decision discusses classification of services.
In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in Powercor's building block proposal. Our preliminary decision on Powercor's annual revenue requirement for each year of the 2016–20 regulatory control period is set out in attachment 1 of the preliminary decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Powercor's proposal that the regulatory control period will commence on 1 January 2016. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Powercor's proposal that the length of the regulatory control period will be five years from 1 January 2016 to 31 December 2020.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(c), the AER does not accept Powercor's proposed total forecast capital expenditure of $2006.3 million ($2015). Our substitute estimate of Powercor's total forecast capex for the 2016–20 regulatory control period is $1610.4 million ($2015). This is discussed in attachment 6 of the preliminary decision.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept Powercor's proposed total forecast operating expenditure inclusive of debt raising costs and exclusive of DMIA of $1330.7 million ($2015). Our substitute estimate of Powercor's total forecast opex for the 2016–20 regulatory control period is $1164.2 million ($2015).This is discussed in attachment 7 of the preliminary decision.
In accordance with clause 6.12.1(4A)(i) and (iv) the AER determines that Powercor's proposed 'earth fault current limiting' and 'codified areas' contingent projects' are contingent projects. In accordance with clause 6.12.1(4A)(i) and (iv) the AER determines that Powercor's proposed 'privately owned electric lines' contingent project is not a contingent project. Our reasons for these conclusions are in attachment 6 of the preliminary decision.
Powercor included three proposed contingent projects in its regulatory proposal for the 2016–20 regulatory control period. Therefore: • In accordance with clause 6.12.1(4A)(ii), the AER is satisfied that the capital expenditure of $63 million ($2015) for the 'earth fault current limiting' contingent project of reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors. • In accordance with clause 6.12.1(4A)(ii), the AER is satisfied that the capital expenditure of $235 million ($2015) for the 'codified areas' contingent project reasonably reflects the capital expenditure criteria, taking into account the

[85] NER, cl. 6.12.1.

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capital expenditure factors. • In accordance with clause 6.12.1(4A)(iii), the AER specifies the trigger event in relation to the 'earth fault current limiting' contingent project is: The contingent project is subject to the three part trigger: 1. Passage by the State of Victoria of a law or regulations or other regulatory instrument that gives effect to recommendation 27 of the Victorian Bushfires Royal Commission, whether in part or in full. 2. The formation of capital projects into tranches. All the projects which constitute a tranche must be listed in a regulatory instrument or a bushfire mitigation plan approved by Energy Safe Victoria for completion in the 2016–2020 regulatory control period. 3. Every project incorporated in a tranche must be subject of a detailed design investigation which accurately identifies the scope of works and proposed costings. • In accordance with clause 6.12.1(4A)(iii), the AER specifies the trigger event in relation to the 'codified areas' contingent project is: The contingent project is subject to the three part trigger: 1. Passage by the State of Victoria of a law or regulations or other regulatory instrument that gives effect to recommendation 27 of the Victorian Bushfires Royal Commission, whether in part or in full. 2. The formation of capital projects into tranches. All the projects which constitute a tranche must be listed in a regulatory instrument or a bushfire mitigation plan approved by Energy Safe Victoria for completion in the 2016–2020 regulatory control period. 3. Every project incorporated in a tranche must be subject of a detailed design investigation which accurately identifies the scope of works and proposed costings. • In accordance with clause 6.12.1(4A)(iv), the AER determines that the proposed 'privately owned electric lines' contingent project is not a contingent project because we are not satisfied that the event is probable or will occur at all in the next period.
In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the first regulatory year of the regulatory control period in accordance with clause 6.5.2 is not to accept Powercor's proposal of 7.20 per cent. Our decision on the allowed rate of return for the first regulatory year of the regulatory control period is 6.02 per cent as set out in table 3.1 of attachment 3 of the preliminary decision. This rate of return will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 (appendix I) of the preliminary decision.
In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in attachment 4 of the preliminary decision.
In accordance with clause 6.12.1(6) the AER's decision on Powercor's regulatory asset base as at 1 January 2016 in accordance with clause 6.5.1 and schedule 6.2 is $3344.4 million. This is set out in attachment 2 of the preliminary decision.
In accordance with clause 6.12.1(7) the AER does not accept Powercor's proposed corporate income tax of $244.8 million ($ nominal). Our decision on Powercor's corporate income tax is $167.0 million ($ nominal). This is set out in attachment 8 of the preliminary decision.
In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by Powercor. This is set out in attachment 5 of the preliminary decision.
In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply: • In accordance with clause 6.12.1(9) of the NER, the AER's decision is to apply version 2 of the EBSS to Powercor in the 2016–20 regulatory control period. This is set out in attachment 9 of the preliminary decision. • In accordance with clause 6.12.1(9) of the NER, we will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to Powercor in the 2016–20 regulatory control period. CESS is discussed in

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attachment 10 of the preliminary decision.
• In accordance with clause 6.12.1(9) of the NER, we will apply our Service Target Performance Incentive Scheme (STPIS) to Powercor for the 2016–20 regulatory control period. STPIS is discussed in attachment 11 of the preliminary decision.
  ○ We will apply the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) reliability of supply parameters, and momentary average interruption frequency index (MAIFI). We will also apply the customer service telephone answering parameter. We will not apply a guaranteed service level scheme as Powercor must comply with its existing Victorian jurisdictional guaranteed service level scheme.
  ○ A beta of 2.5 will be used to calculate the major event day boundary.
  ○ Our decision on the SAIDI and SAIFI incentive rates and performance targets to apply to Powercor for the 2016–20 regulatory control period are set out in tables 11.1 and 11.2 of attachment 11 of this preliminary decision.
  ○ Our decision on the customer service incentive rate and performance target are set out in section 11.1 of attachment 11 of this preliminary decision.
  ○ The revenue at risk for Powercor will be capped at ±5.0 per cent. Within this there will be a cap of ±0.5 per cent on the telephone answering parameter for performance.
  Note: The meaning for year "t" under the price control formula for this determination is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.
• In accordance with Division 4 of Part 3 to the National Electricity (Victoria) Act 2005 and the NER, the AER will make a final adjustment to close out the ESCV's s-factor scheme for the 2006–10 regulatory control period by including the adjustment amount shown in attachment 11 in the 'revenue adjustments' row of the post-tax revenue model.
• The AER has determined to continue Part A of the Demand Management Innovation Scheme (DMIS) for Powercor in the 2016–20 regulatory control period (that is, the DMIA component). DMIS is discussed in attachment 12 of the preliminary decision.

In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.
In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Powercor for any given regulatory year is the total annual revenue calculated using the formula in attachment 14 plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 14 in the preliminary decision.
In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps for all services other than metering, for which a revenue cap will apply. This is discussed in attachment 16 in the preliminary decision.
In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, the AER's decision is Powercor must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 14 in the preliminary decision.
In accordance with clause 6.12.1(14) the AER's decision on the additional pass through events that are to apply is to not accept the nominated pass through events as proposed by Powercor. The AER also substitutes its own definitions for the following events: • insurance event • insurer credit risk event • natural disaster event • terrorism event • retailer failure event.
In accordance with clause 6.12.1(15) the AER's decision is to approve Powercor's proposed negotiating framework.

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The negotiating framework that is to apply to Powercor is set out at attachment 17 of the preliminary decision.
In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in May 2015 to Powercor. This is set out is at attachment 17of the preliminary decision.
In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes for Powercor is set out at attachment 14 of the preliminary decision.
In accordance with clause 6.12.1(18) the AER's decision on regulatory depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of Powercor's regulatory control period (1 January 2021). This is discussed in attachment 2 of the preliminary decision.
In accordance with clause 6.12.1(19) the AER's decision on how Powercor is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 14 of the preliminary decision.
In accordance with clause 6.12.1(20) the AER's decision is we require Powercor to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the preliminary decision.
In accordance with section 16C of the National Electricity (Victoria) Act 2005, the NEL, the NER and the Victorian F-Factor Scheme Order In Council 2011, we will apply the f-factor scheme based on an incentive rate of $25,000 per fire start higher/lower than the f-factor target as set out in attachment 18 of the preliminary decision.

B List of Submissions

We received 29 submissions in response to Powercor's regulatory proposal as listed below:

	Submission from	Date received	Submission on
1	Bendigo Manufacturing Group	13/07/2015	Regulatory Proposals
2	Cardinia Shire Council	01/07/2015	Public Lighting
3	CitiPower Powercor	13/07/2015	Regulatory Proposals
4	Citelum Group	24/06/2015	Public Lighting
5	City of Greater Dandenong	10/07/2015	Public Lighting
6	City of Casey	13/07/2015	Public Lighting
7	City of Greater Bendigo	13/07/2015	Public Lighting
8	City of Greater Geelong	13/07/2015	Public Lighting
9	City of Mooney Valley	07/07/2015	Public Lighting
10	Consumer Challenge Panel Sub-Panel 3	23/05/2015	Regulatory Proposals
11	Consumer Challenge Panel Sub-Panel 3	05/08/2015	Regulatory Proposals
12	Consumer Utilities Advocacy Centre	13/07/2015	Regulatory Proposals
13	Department of Economic Development, Jobs, Transport and Resources (Victorian Government)	13/07/2015	Regulatory Proposals
14	East Gippsland Shire Council	13/07/2015	Public Lighting
15	Energy Retailers Association of Australia	13/07/2015	Regulatory Proposals
16	Ethnic Communities' Council of Victoria	26/06/2015	Regulatory Proposals
17	Glen Eira City Council	10/07/2015	Public Lighting
18	Gannawarra Shire Council	16/07/2015	Public Lighting
19	Hume City Council	13/07/2015	Public Lighting
20	Latrobe City Council	13/07/2015	Public Lighting
21	Indigo Shire Council	23/07/2015	Public Lighting
22	Municipal Association of Victoria	13/07/2015	Public Lighting
23	Origin Energy	13/07/2015	Regulatory Proposals
24	Murrindindi Shire Council	17/07/2015	Public Lighting
25	Vector	13/07/2015	Regulatory Proposals
26	Victorian Energy Consumer and User Alliance	13/07/2015	Regulatory Proposals
27	VicRoads	13/07/2015	Public Lighting
28	Victorian Greenhouse Alliances	13/07/2015	Regulatory Proposals

	Submission from	Date received	Submission on
29	Yarra Ranges Council	13/07/2015	Public Lighting