PRELIMINARY DECISION
Powercor distribution determination
2016 to 2020

Attachment 6 – Capital expenditure

October 2015

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@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

Attachment 13 - Classification of services

Attachment 14 - Control mechanism

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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

6 Capital expenditure

Capital expenditure (capex) refers to the investment made in the network to provide standard control services. This investment mostly relates to assets with long lives (30–50 years is typical) and these costs are recovered over several regulatory control periods. On an annual basis, however, the financing cost and depreciation associated with these assets are recovered (return of and on capital) as part of the building blocks that form Powercor's total revenue requirement.[1]

This attachment sets out our preliminary decision on Powercor's total forecast capex. Further detailed analysis is in the following appendices:

- Appendix A - Assessment Techniques
- Appendix B - Assessment of capex drivers
- Appendix C - Demand
- Appendix D- Predictive modelling approach and scenarios
- Appendix E - VBRC: Confidential appendix.

6.1 Preliminary decision

We are not satisfied Powercor's proposed total forecast capex of $2,006.3 million ($2015) reasonably reflects the capex criteria. This is 25.0 per cent greater than the AER's allowance for the 2011–15 regulatory control period ($1,604.6 million) and 29.4 per cent greater than actual capex for the 2011–15 period ($1,550.8 million). We substituted our estimate of Powercor's total forecast capex for the 2016–20 regulatory control period. We are satisfied that our substitute estimate of $1,610.4 million ($2015) reasonably reflects the capex criteria. Table 6.1 outlines our preliminary decision.

[1] NER, cl. 6.4.3(a).

Table 6.1 Our preliminary decision on Powercor's total forecast capex ($2015, million)

	2016	2017	2018	2019	2020	Total
Powercor's proposal	392.3	399.3	406.4	397.8	410.5	2006.3
AER preliminary decision	320.4	321.3	324.9	316.6	327.2	1610.4
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.

Table 6.2 summarises our findings and the reasons for our preliminary decision.

These reasons include our responses to stakeholders' submissions on Powercor's regulatory proposal. In the table we present our reasons by 'capex driver' (for example, augmentation, replacement, and connections). This reflects the way in which we tested Powercor's total forecast capex. Our testing used techniques tailored to the different capex drivers, taking into account the best available evidence. Through our techniques, we found Powercor's capex forecast across all categories was higher than an efficient level, inconsistent with the NER. We are not satisfied that Powercor's proposed total forecast capex is consistent with the requirements of the NER.[2]

Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. Our preliminary decision concerns Powercor's total forecast capex for the 2016–20 regulatory control period. We do not approve an amount of forecast expenditure for each capex driver. However, we use our findings on the different capex drivers to arrive at an alternative estimate for total capex. We test this total estimate of capex against the requirements of the NER (see section 0 for a detailed discussion). We are satisfied that our estimate represents the total forecast capex that as a whole reasonably reflects the capex criteria.

Table 6.2 Summary of AER reasons and findings

Issue	Reasons and findings
Total capex forecast	Powercor's proposed a total capex forecast of $2,006.3 million ($2015) in its proposal. We are not satisfied this forecast reflects the capex criteria. We are satisfied our substitute estimate of $1,610.4 million ($2015) reasonably reflects the capex criteria. Our substitute estimate is 19.7 per cent lower than Powercor's proposal. The reasons for this decision are summarised in this table and detailed in the

2 NER, cll. 6.5.7(c) and (d).

Issue	Reasons and findings
	remainder of this attachment.
Forecasting methodology, key assumptions and past capex performance	We consider Powercor's key assumptions and forecasting methodology are generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment and section 6.4.2.
Augmentation capex	We do not accept Powercor's forecast augex of $362.3 million ($2015) as a reasonable estimate for this category. We consider that $241.6 ($2015) million is a reasonable estimate for Powercor to meet forecast demand growth and satisfy the capex criteria, including for augex relating to the VBRC. This is 33 per cent less than Powercor's augmentation capex forecast. In coming to this view we do not accept that Powercor's demand forecast reflects a realistic expectation of demand over the 2016–20 regulatory control period. Our estimate reflects the augex necessary for Powercor to meet a lower forecast of demand.
Customer connections capex	We do not accept Powercor's' forecast gross connections capex of $774.1 million ($2015) as a reasonable estimate for this category.[3] We consider our substitute estimate of $724.6 million ($2015) will allow Powercor to meet the capex objectives and have included this amount in our substitute gross connections capex estimate. We are not satisfied that the approach Powercor has adopted to generate the forecast represents a reasonable estimate of the capex Powercor requires to meet the objectives.
Asset replacement capex (repex)	We do not accept Powercor's forecast repex of $722 million ($2015) as a reasonable estimate for this category. We consider our alternative estimate of $609 million ($2015) will allow Powercor to meet the capex objectives and have included this amount in our alternative estimate. Our alternative estimate is 16 per cent lower than Powercor's proposed repex. 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.
Non-network capex	We do not accept Powercor's proposed non-network capex of $262.1 million ($2015). We have instead included an amount of $226.4 million ($2015), excluding overheads. We accept Powercor's forecasts for buildings and property, fleet, and tools and equipment capex as reasonably reflecting required expenditure in these categories. We do not accept Powercor's forecast for IT capex. In our view, Powercor's IT forecast does not reflect the efficient costs of a prudent operator. We consider that some elements of the forecast IT capex program have not been fully justified or are speculative in nature. We are satisfied our alternative estimate reasonably reflects the capex criteria.
Capitalised overheads	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. Given that our assessment of Powercor's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in Powercor's proposal, it follows that we would expect some reduction in the size of Powercor's capitalised overheads. We reduced Powercor's capitalised overheads accordingly.
Real cost escalators	In respect of real material cost escalators (leading to cost increases above CPI),

[3] Powercor's RIN included forecast gross connections capex of $649.3 million ($2015). Our assessment used information from information subsequently provided by Powercor. Based on this additional information, we assessed a $774.1 million capex forecast for Powercor's connections category. See Powercor, *Response to AER Information Request 012*, 24 July 2015.

Issue	Reasons and findings
	Powercor accepted the AER's application of CPI indexation as a proxy for forecasts of escalation of materials costs in real terms over the 2016–20 regulatory control period. Our approach to real materials cost escalation does not affect the proposed application of labour and construction cost escalators which apply to Powercor's forecast capex for standard control services. We are not satisfied Powercor's proposed real labour cost escalators which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period. We discuss our assessment of forecast our labour price growth for Powercor in attachment 7. The difference between the impact of the real labour cost escalation proposed by Powercor and that accepted by the AER in its capex decision is $29.9 million ($2015).

Source: AER analysis.

We consider that our overall capex forecast addresses the revenue and pricing principles. In particular, we consider our overall capex forecast provides Powercor a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[4]

As set out in appendix B we are satisfied that our overall capex forecast is consistent with the national electricity objective (NEO). We consider our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.

We also consider that overall our capex forecast addresses the capital expenditure objectives.[5] In making our preliminary decision, we specifically considered the impact our decision will have on the safety and reliability of Powercor's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in Powercor's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

6.2 Powercor's proposal

Powercor proposed total forecast capex of $2,006.3 million ($2015) for the 2016–20 regulatory control period.[6] This is $455.5 ($2015) million above Powercor's actual capex of $1,550.8 million ($2015) for the 2011–15 regulatory control period.[7]

Powercor expected new customer connections to be the largest capex category, accounting for approximately 37 per cent of its total forecast capex. Replacement

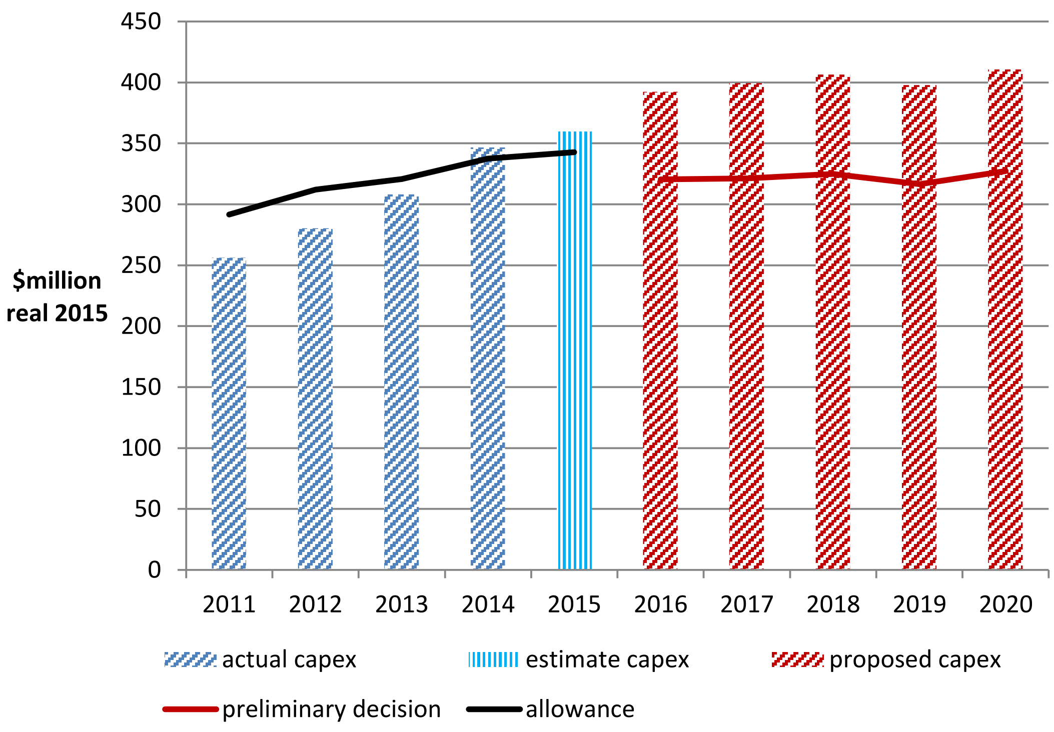
4 NEL, s. 7A.
5 NER, cl. 6.5.7(a).
6 This is net capex, which does not include customer contributions.
7 This includes estimated capex for the 2015 regulatory year.

expenditure (repex) is also significant, accounting for approximately 31 percent of the total capex forecast. Powercor stated the main drivers for its capex program include:[8]

- connection projects related to the expanding dairy industry, new wind farms and a government initiative
- population growth and transmission-level network constraints driving additional network capacity requirements
- mitigating the potential for increased failure rates on aging lines and poles through increased rates of replacement
- mitigating bushfire risk from powerlines in response to the Victorian Bushfires Royal Commission (VBRC).

Figure 6.1 shows Powercor's forecast capex for each year of the 2016–20 regulatory control period. It also shows Powercor's actual capex for each year of the 2011–15 regulatory control period.

Figure 6.1 Powercor's total actual and forecast capex 2011–2020



Source: AER analysis.

[8] Powercor, *Regulatory proposal 2016–2020*, 30 April 2015, pp. 101–104.

6.3 AER's assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, and outlines our assessment techniques. It also explains how we derive an alternative estimate of total forecast capex against which we compare the distributor's total forecast capex. The information Powercor provided in its regulatory proposal, including its response to our RIN, is a vital part of our assessment. We also took into account information that Powercor provided in response to our information requests, and submissions from other stakeholders.

Our assessment approach involves the following steps:

- Our starting point for building an alternative estimate is the distributor's regulatory proposal.[9] We apply our various assessment techniques, both qualitative and quantitative, to assess the different elements of the distributor's proposal. This analysis informs our view on whether the distributor's proposal reasonably reflects the capex criteria in the NER at the total capex level.[10] It also provides us with an alternative forecast that we consider meets the criteria. In arriving at our alternative estimate, we weight the various techniques we used in our assessment. We give more weight to techniques we consider are more robust in the particular circumstances of the assessment.
- Having established our alternative estimate of the *total* forecast capex, we can test the distributor's total forecast capex. This includes comparing our alternative estimate total with the distributor's total forecast capex and what the reasons for any differences are. If there is a difference between the two, we may need to exercise our judgement as to what is a reasonable margin of difference.

If we are satisfied the distributor's proposal reasonably reflects the capex criteria in meeting the capex objectives, we will accept it. The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to:[11]

- meet or manage the expected demand for standard control services over the period
- comply with all regulatory obligations or requirements associated with the provision of standard control services
- to the extent that there are no such obligations or requirements, maintain service quality, reliability and security of supply of standard control services and maintain the reliability and security of the distribution system
- maintain the safety of the distribution system through the supply of standard control services.

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9 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; see also AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

10 NER, cl. 6.5.7(c).

11 NER, cl. 6.5.7(a).

If we are not satisfied, the NER requires us to put in place a substitute estimate that we are satisfied reasonably reflects the capex criteria.[12] Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:[13]

- the efficient costs of achieving the capital expenditure objectives
- the costs that a prudent operator would require to achieve the capital expenditure objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The AEMC noted '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[14] Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular categories or projects informs our assessment of the total capex forecast. The AEMC stated:[15]

> It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

In deciding whether we are satisfied that Powercor's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.[16] In taking the capex factors into account, the AEMC noted:[17]

> …this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.5 summarises how we took the capex factors into consideration.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.[18] In particular, we take into account whether our overall capex forecast provides Powercor a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and

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12 NER, cl. 6.12.1(3)(ii).

13 NER, cl. 6.5.7(c).

14 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 113.

15 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012*,* November 2012, p. vii.

16 NER, cl. 6.5.7(e).

17 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 115.

18 NEL, ss. 7A and 16(2).

- complying with its regulatory obligations and requirements.[19]

Expenditure Assessment Guideline

The rule changes the AEMC made in November 2012 required us to make and publish an Expenditure Forecast Assessment Guideline for electricity distribution (Guideline).[20] We released our Guideline in November 2013.[21] The Guideline sets out our proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For Powercor, our framework and approach paper stated that we would apply the Guideline, including the assessment techniques outlined in it.[22] We may depart from our Guideline approach and if we do so, we need to provide reasons. In this determination, we have not departed from the approach set out in our Guideline.

We note that RIN data form part of a distributor's regulatory proposal.[23] In our Guideline we stated we would "require all the data that facilitate the application of our assessment approach and assessment techniques". We also stated that the RIN we issue in advance of a distributor lodging its regulatory proposal would specify the exact information we require.[24] Our Guideline made clear our intention to rely upon RIN data during distribution determinations.

6.3.1 Building an alternative estimate of total forecast capex

The following section sets out the approach we apply to arrive at an alternative estimate of total forecast capex.

Our starting point for building an alternative estimate is the distributor's proposal.[25] We review the proposed forecast methodology and the key assumptions that underlie the distributor's forecast. We also consider the distributor's performance in the previous regulatory control period to inform our alternative estimate.

We then apply our specific assessment techniques to develop an estimate and assess the economic justifications that the distributor puts forward. Many of our techniques encompass the capex factors that we are required to take into account. Appendix A and appendix B contain further details on each of these techniques.

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19 NEL, s. 7A.

20 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 114.

21 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013.

22 AER, *Final Framework and approach for the Victorian Electricity Distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 119–120.

23 NER, cll. 6.8.2(c2) and (d).

24 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 25.

25 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects or programs the distributor should or should not undertake. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects. Rather, we approve an overall revenue requirement that includes an assessment of what we find to be an efficient total capex forecast.[26]

We determine total revenue by reference to our analysis of the proposed capex and the various building blocks. Once we approve total revenue, the distributor is able to prioritise its capex program given its circumstances over the course of the regulatory control period. The distributor may need to undertake projects or programs it did not anticipate during the distribution determination. The distributor may also not require some of the projects or programs it proposed for the regulatory control period. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period in its decision-making.

As we explained in our Guideline:[27]

> Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but we intend to consider the inter-connections between our assessment techniques when determining total capex … forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques.

In arriving at our estimate, we weight the various techniques we used in our assessment. We weight these techniques on a case by case basis using our judgement. Broadly, we give more weight to techniques we consider are more robust in the particular circumstances of the assessment. By relying on a number of techniques, we ensure we consider a wide variety of information and can take a holistic approach to assessing the distributor’s capex forecast.

Where our techniques involve the use of a consultant, we consider their reports as one of the inputs to arriving at our preliminary decision on overall capex. Our preliminary decision clearly sets out the extent to which we accept our consultants' findings. Where we apply our consultants’ findings, we do so only after carefully reviewing their analysis and conclusions, and evaluating these against outcomes of our other techniques and our examination of Powercor's proposal.

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26 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. vii.

27 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 12.

We also take into account the various interrelationships between the total forecast capex and other components of a distributor's distribution determination. The other components that directly affect the total forecast capex include:

- forecast opex
- forecast demand
- the service target performance incentive scheme
- the capital expenditure sharing scheme
- real cost escalation
- contingent projects.

We discuss how these components impact the total forecast capex in Table 6.4.

Underlying our approach are two general assumptions:

- The capex criteria relating to a prudent operator and efficient costs are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[28]
- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.[29]

6.3.2 Comparing the distributor's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the distributor's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the distributor's proposal. The distributor's forecast methodology and its key assumptions may explain any differences between our alternative estimate and its proposal.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[30]

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[28] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013 , pp. 8 and 9. The Australian Competition Tribunal has previously endorsed this approach: see : Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by EnergyAustralia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by United Energy Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA).

[29] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

[30] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 112.

> The AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

As noted above, we draw on a range of techniques, as well as our assessment of elements that impact upon capex such as demand and real cost escalators.

Our decision on the total forecast capex does not strictly limit a distributor's actual spending. A distributor might spend more on capex than the total forecast capex amount specified in our decision in response to unanticipated expenditure needs.

The regulatory framework has a number of mechanisms to deal with such circumstances. Importantly, a distributor does not bear the full cost where unexpected events lead to an overspend of the approved capex forecast. Rather, the distributor bears 30 per cent of this cost if the expenditure is subsequently found to be prudent and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant, unexpected capex to customers, where appropriate.[31] Similarly, a distributor may spend less than the capex forecast because they have been more efficient than expected. In this case the distributor will keep on average 30 per cent of this reduction over time.

We set our alternative estimate at the level where the distributor has a reasonable opportunity to recover efficient costs. The regulatory framework allows the distributor to respond to any unanticipated issues that arise during the regulatory control period. In the event that this leads to the approved total revenue underestimating the total capex required, the distributor should have sufficient flexibility to allow it to meet its safety and reliability obligations by reallocating its budget. Conversely, if there is an overestimation, the stronger incentives the AEMC put in place in 2012 should result in the distributor only spending what is efficient. As noted the distributor and consumers share the benefits of the underspend and the costs of an overspend under the regulatory regime.

6.4 Reasons for preliminary decision

We applied the assessment approach set out in section 6.3 to Powercor. In this preliminary decision, we are not satisfied Powercor's total forecast capex reasonably reflects the capex criteria. We compared Powercor's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. Powercor's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

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[31] NER, r. 6.6.

Table 6.3 sets out the capex amounts by driver that we included in our alternative estimate of Powercor’s total forecast capex for the 2016–20 regulatory control period.

Table 6.3 Our assessment of required capex by capex driver 2016–20 ($2015, million)

Category	2016	2017	2018	2019	2020	Total
Augmentation	50.8	50.6	50.3	44.3	45.6	241.6
Connections	151.2	158.1	139.4	137.0	138.9	724.6
Replacement	110.7	108.7	122.4	127.2	139.7	608.7
Non-Network	48.9	49.6	49.1	42.0	36.7	226.4
Capitalised overheads	36.8	38.1	39.5	41.0	42.3	197.7
Labour escalation adjustment	-2.9	-5.5	-6.4	-7.1	-8.1	-29.9
Gross Capex (includes capital contributions)	**395.6**	**399.7**	**394.3**	**384.5**	**395.1**	**1969.1**
Capital Contributions	75.2	78.4	69.4	67.9	67.9	358.8
Net Capex (excluding capital contributions)	**320.4**	**321.3**	**324.9**	**316.6**	**327.2**	**1610.3**

Source: AER analysis.

Note: Numbers may not add up due to rounding.

We discuss our assessment of Powercor's forecasting methodology, key assumptions and past capex performance in the sections below.

Our assessment of capex drivers are in appendices A and B. These set out the application of our assessment techniques to the capex drivers, and the weighting we gave to particular techniques. We used our reasoning in the appendices to form our alternative estimate.

6.4.1 Key assumptions

The NER requires Powercor to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex. Powercor must also provide a certification by its Directors that those key assumptions are reasonable.[32]

The key assumptions that underlie Powercor’s capex forecast include:[33]

- stakeholder engagement feedback

[32] NER, cll. S6.1.1.1(2), (4) and (5).

[33] Powercor, *Regulatory proposal 2016–2020: Attachment 0.1: Certification of reasonableness of key assumptions*, 30 April 2015, pp. 2–3.

- labour escalation forecast
- contract escalation forecast
- current or impending regulatory obligations
- replacement program is appropriate to meet the capital expenditure objectives of the NER
- spatial peak demand growth forecast
- augmentation expenditure forecast consistent with compliance obligations under the Victorian Electricity Distribution Code
- network capacity program is appropriate to meet the capital expenditure objectives of the NER
- customer connection forecast, where customer contributions are based on Electricity Industry Guideline 14 requirements.

We assessed Powercor's key assumptions in the appendices to this capex attachment.

6.4.2 Forecasting methodology

The NER requires Powercor to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[34] Powercor must include this information in its regulatory proposal.[35]

The main points of Powercor's forecasting methodology are:[36]

- Powercor's capex forecast comprise the following categories consistent with the Expenditure Assessment Guideline: replacement, augmentation, connection and customer driven works, and non-network. Powercor also included an additional category related to the Victorian Bushfires Royal Commission (VBRC).
- Powercor developed its capex forecast having reference to asset management plans, and planning policies and guidelines across a range of expenditure categories. Powercor also engaged independent, expert advice to review and support its plans, processes and expenditure forecasts.
- Powercor modelled expenditure for a range of capex categories. These base capex models contain direct costs only. Powercor subsequently applied escalations and other factors through other models to arrive at the final capex forecast.
- Powercor developed a deliverability plan to ensure it is able to deliver its capex forecast. The deliverability plan will utilise internal labour resources, supplemented by external subcontractors, as required.

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[34] NER, cll. 6.8.1A and 11.60.3(c).

[35] NER, cl. S6.1.1(2).

[36] Powercor, *Regulatory proposal 2016–2020: Appendix E: Capital expenditure*, 30 April 2015, pp. 12–17.

We consider Powercor's forecasting methodology is generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment.

The Victorian Energy Consumer and Use Alliance (VECUA) considered the Victorian distributors overly relied on bottom up methodologies with insufficient regard to top down methods.[37] Origin Energy supported the application of both a top down and bottom up assessment:[38]

> to demonstrate that a level of overall restraint has been brought to bear. This dual exercise is necessary to ensure that forecast costs, including unit rates, have not been overstated and that inter-relationships and synergies between projects or areas of work which are more readily identified at a portfolio level are adequately accounted for.

As we noted in previous determinations, the drawback of deriving a capex forecast through a bottom-up assessment is it does not of itself provide sufficient evidence that the estimate is efficient. Bottom up approaches tend to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work. In contrast, reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency.[39]

6.4.3 Interaction with the STPIS

We consider our approved capital expenditure forecast is consistent with the setting of targets under the STPIS. In particular, we should not set the capex allowance such that it would lead to Powercor systematically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow a prudent and efficient service provider in Powercor’s circumstances to maintain performance at the targets set under the STPIS. As such, it is appropriate to apply the STPIS as set out in attachment 11.

In making our preliminary decision, we specifically considered the impact our decision will have on the safety and reliability of Powercor’s network.

In its submission, the CCP noted the following explanation from the AEMC:[40]

> …operating and capital expenditure allowances for NSPs should be no more than the level considered necessary to comply with the relevant regulatory obligation or requirement, where these have been set by the body allocated to that role. Expenditure by NSPs to achieve standards above these levels should

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[37] VECUA, *Submission: Victorian distribution networks’ 2016–20 revenue proposals*, 13 July 2015, p. 19.

[38] Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 13 July 2015, p. 8.

[39] For example, see AER, *Preliminary decision: Ergon Energy determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, April 2015, pp. 22–23.

[40] CCP, *Advice to the AER: AER’s Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks’ revised regulatory proposal*, August 2015, p. 27.

> be unnecessary, as they are only required to deliver to the standards set. It would also amount to the AER substituting a regulatory obligation or requirement with its own views on the appropriate level of reliability, which would undermine the role of the standard setting body, and create uncertainty and duplication of roles.
>
> NSPs are still free to make incremental improvements over and above the regulatory requirements at their own discretion. Such additional expenditure will not generally be recoverable, through forecast capital and operating expenditure. However, DNSPs are also provided with annual financial incentives to improve reliability performance under the STPIS.

We consider our substitute estimate is sufficient for Powercor to maintain the safety, service quality and reliability of its network consistent with its obligations. Our provision of a total capex forecast does not constrain a distributor's actual spending—either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a distributor might wish to spend particular capital expenditure differently or in excess of the total capex forecast in our decision. . However, such additional expenditure is not included in our assessment of expenditure forecasts as it is not required to meet the capex objectives. We consider the STPIS is the appropriate mechanism to provide distributors with the incentive to improve reliability performance where such improvements reflect value to the energy customer.

Under our analysis of specific capex drivers, we explained how our analysis and certain assessment techniques factor in safety and reliability obligations and requirements.

6.4.4 Powercor's capex performance

We looked at a number of historical metrics of Powercor's capex performance against other distributors in the national electricity market (NEM). We also compared Powercor's capex forecast against historical trends. These metrics are largely based on outputs of the annual benchmarking report and other analysis using data the distributors provided for the annual benchmarking report. The report includes Powercor's relative partial and multilateral total factor productivity (MTFP) performance, capex per customer and maximum demand, and Powercor's historical capex trend.

The NER sets out that we must have regard to our annual benchmarking report.[41] This section shows how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall understanding of Powercor's proposal in a broader context. However, in our capex assessment we have not relied on the high level benchmarking metrics set out below other than to gain a high level insight into Powercor's proposal. We have not used this analysis deterministically in our capex assessment.

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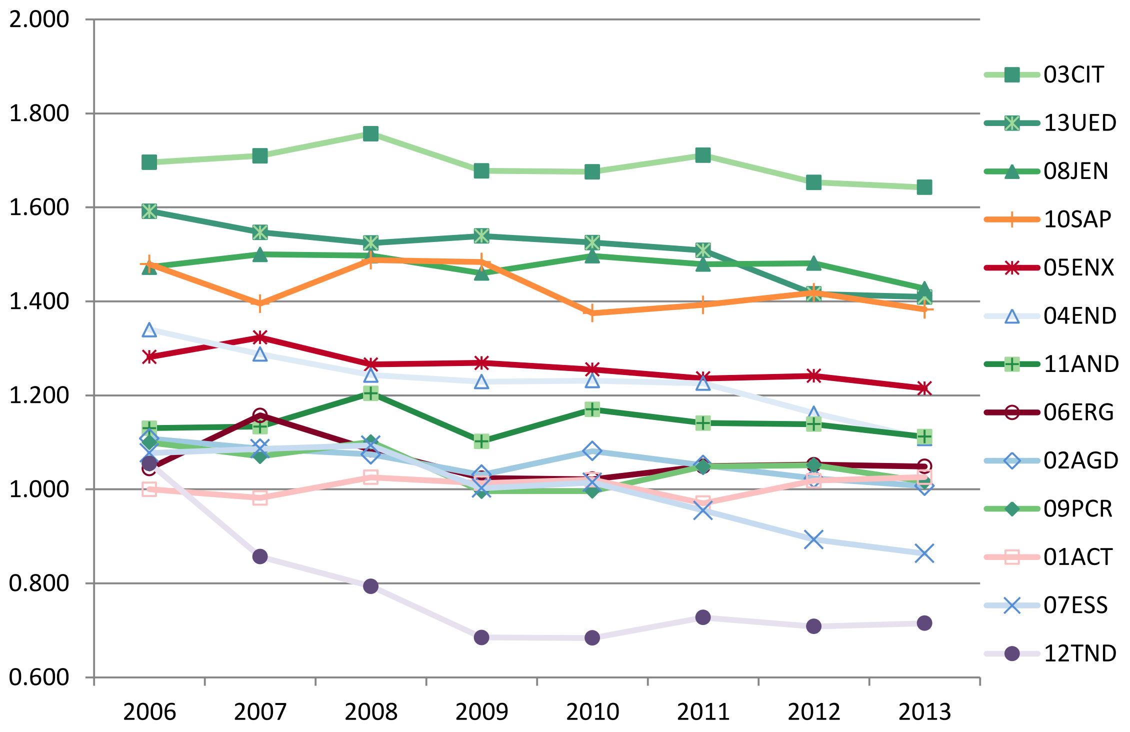
[41] NER, cl. 6.5.7(e).

Partial factor productivity of capital and multilateral total factor productivity

Figure 6.2 shows a measure of partial factor productivity of capital from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. Unlike the other Victorian distributors, Powercor is among the lesser performers in this metric.

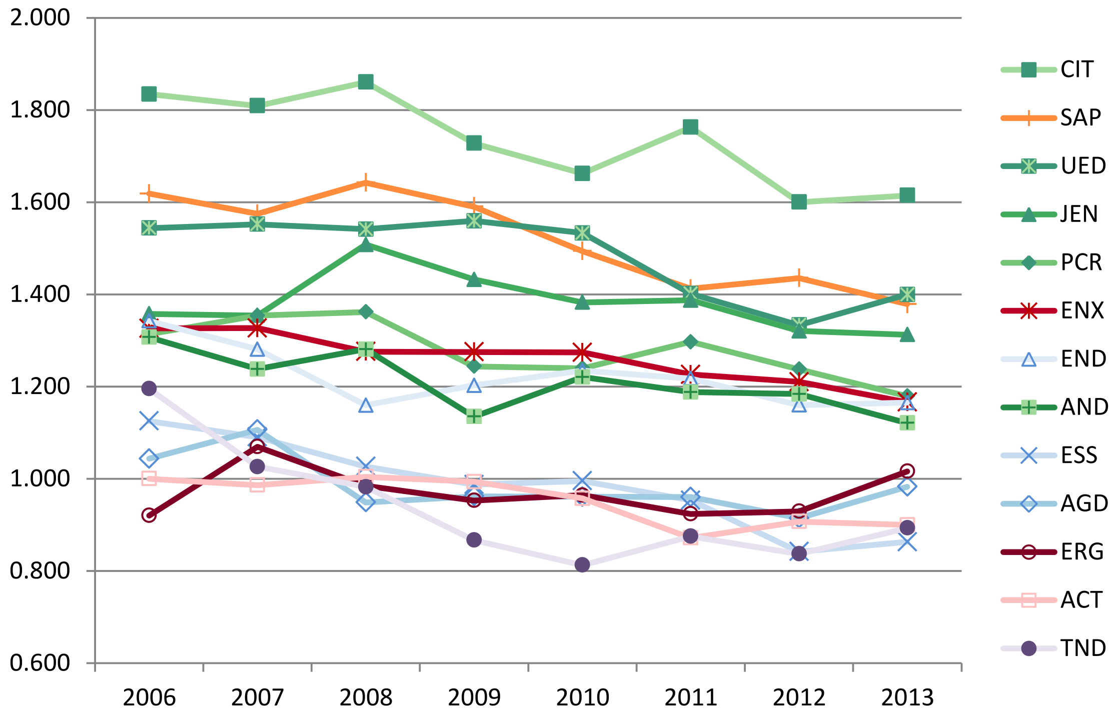
Figure 6.2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 33.

Figure 6.3 shows the performance on MTFP. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length). Powercor is among the better performers in this metric.

Figure 6.3 Multilateral total factor productivity



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 31.

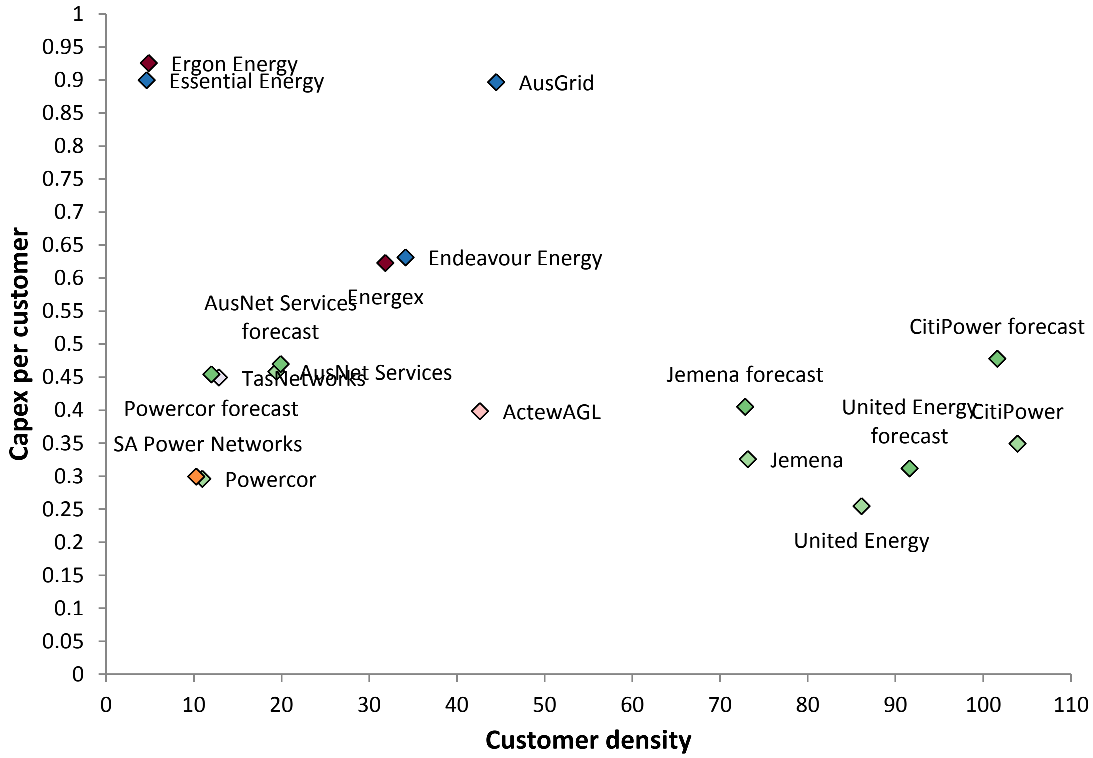
Relative capex efficiency metrics

Figure 6.4 and Figure 6.5 show capex per customer and per maximum demand, against customer density. Unless otherwise indicated as a forecast, the figures represent the five year average of each distributor's actual capex for the years 2008–12. We considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6.4 and Figure 6.5 show the Victorian distributors generally perform well in these metrics compared to other distributors in the NEM in the 2008–12 years. For completeness, we also included the other Victorian distributors' proposed capex for the 2016–20 regulatory control period in the figures. However, we do not use comparisons of Powercor's total forecast capex with the total forecast capex of the other Victorian distributors as inputs to our assessment. We consider it is appropriate to compare Powercor's forecast only with actual capex. This is because actual capex are 'revealed costs' and would have occurred under the incentives of a regulatory regime.

Figure 6.4 shows Powercor spent the least amount of capex per customer among the low density networks in the 2008–12 years. However, Powercor's capex per customer will increase in the 2016–20 period based on their proposed forecast capex.

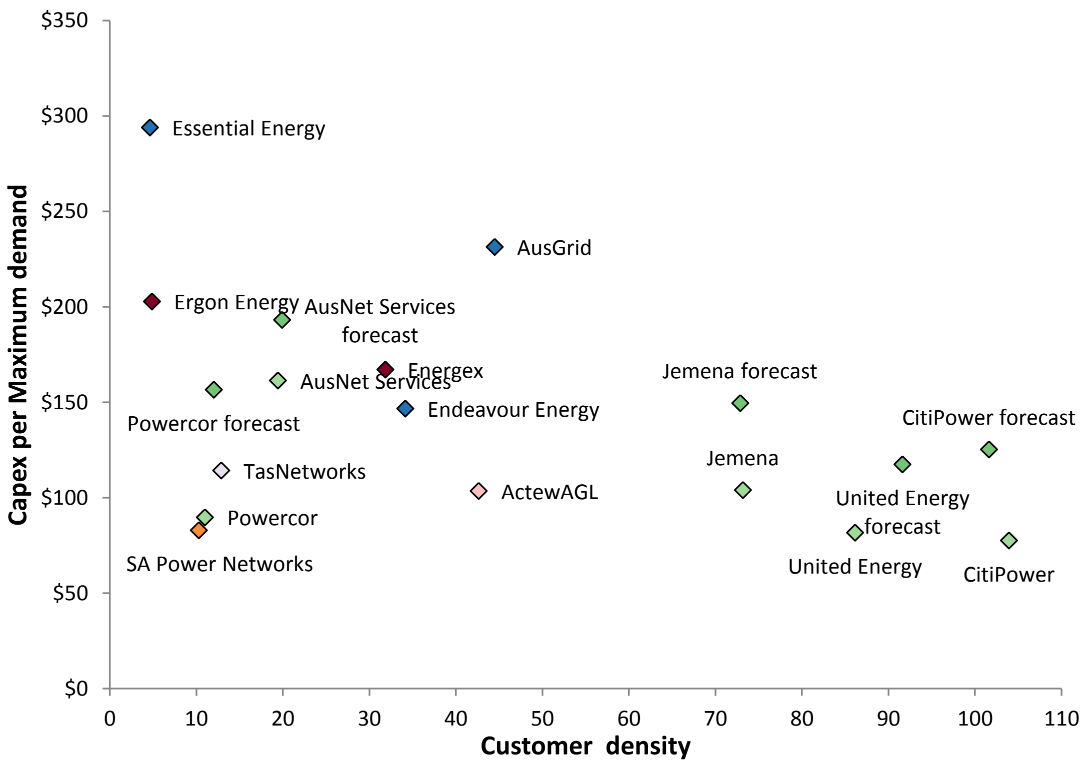
Figure 6.4 Capex per customer (000s, $2013-14), against customer density



Source: AER analysis.

Similar to Figure 6.4, Figure 6.5 shows Powercor spent among the least amount of capex per maximum demand among the low density networks in the 2008–12 years. However, Powercor's this metric will increase in the 2016–20 period based on their proposed forecast capex.

Figure 6.5 Capex per maximum demand (000s, $2013-14), against customer density



Source: AER analysis.

The Consumer Utilities Advocacy Centre (CUAC) expressed concern about the large increases in capex some Victorian distributors proposed and the decline in productivity in recent years.[42]

The Victorian Greenhouse Alliances (VGA) noted the increases in the capex forecast of the Victorian distributors. The VGA considered the increased capex forecasts were concerning given over-investment over recent regulatory control periods has led to excess levels of network capacity and declining network utilisation. The VGA also expressed concern that the Victorian distributors proposed such high levels of capex at a time of:[43]

- declining capacity utilisation
- reduced average asset age for most asset categories
- static or falling demand and consumption
- reductions in the reliability standards.

[42] CUAC, *Submission: Victorian electricity distribution pricing review (EDPR) 2016 to 2020*, 13 July 2015, p. 2.

[43] VGA, *Submission: Local Government response to the Victorian electricity distribution price review (EDPR) 2016–20*, July 2015, p. 33.

The Department of Economic Development, Jobs, Transport and Resources (DEDJTR) and the VECUA made similar points in their submissions.[44]

Appendix B details our assessment of Powercor's capex categories. These assessments, along with the high level analysis in this section 6.4.4, were inputs into our preliminary decision on Powercor's total capex for the 2016–20 regulatory control period. We consider our assessment results in a total capex forecast that is largely consistent with these submissions. Figure 6.1 shows our preliminary decision capex forecast is 3.9 per cent higher than Powercor's actual capex in the 2011–15 regulatory control period. By comparison, Powercor's proposed capex is 29.4 per cent higher than its actual capex for the 2011–15 regulatory control period.

To arrive at our preliminary decision, we considered the issues noted in these submissions, such as lower demand and declining utilisation in the network. For example, we consider Power's demand forecast does not reflect a realistic expectation of demand over 2016–20 and substituted a lower demand forecast (see appendix C). Our assessment of Powercor's augex forecast reflects this lower demand forecast (see section B.2). Importantly, our assessment considered many other factors such as asset age and condition. We discuss these and other issues relevant to Powercor's capex proposal in detail in appendix B.

Powercor’s historic capex trends

We compared Powercor’s capex proposal for the 2016–20 regulatory control period against the long term historical trend in capex levels.

Figure 6.6 shows actual historical capex and proposed capex between 2001 and 2020. This figure shows that Powercor's forecast is significantly higher than historical levels (actual spend).

The Consumer Challenge Panel (CCP) noted capex in the current period occurred under the 'old' national electricity rules, which the CCP considered overtly incentivised investment.[45] The CCP further noted the NER did not apply in Victoria prior to 2011. Despite the lower incentive in prior to 2011, the CCP noted that reliability did not suffer.[46]

Our detailed assessment in appendix B examined whether the increase in capex is reasonably reflective of the capex criteria.

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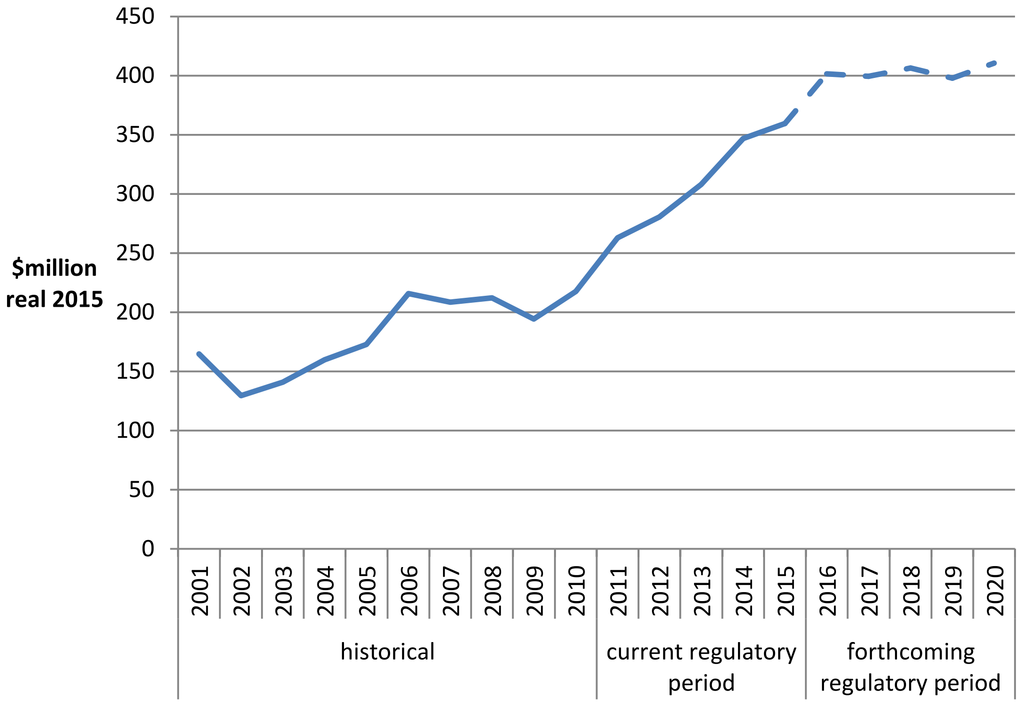
[44] DEDJTR, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 6; VECUA, *Submission: Victorian distribution networks’ 2016–20 revenue proposals*, 13 July 2105, pp. 6 and 18.

[45] That is, prior the AEMC's changes to the NER in Nov ember 2012.

[46] CCP, *Submission: Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 5 August 2015, p. 41.

Figure 6.6 Powercor total capex - historical and forecast for 2001–2020



Source: AER analysis.

6.4.5 Interrelationships

There are a number of interrelationships between Powercor's total forecast capex for the 2016–20 regulatory control period and other components of its distribution determination (see Table 6.4). We considered these interrelationships in coming to our preliminary decision on total forecast capex.

Table 6.4 Interrelationships between total forecast capex and other components

Other component	Interrelationships with total forecast capex
Total forecast opex	There are elements of Powercor's total forecast opex that are specifically related to its total forecast capex. These include the forecast labour price growth that we included in our opex forecast in Attachment 7. This is because the price of labour affects both total forecast capex and total forecast opex. More generally, we note our total opex forecast will provide Powercor with sufficient opex to maintain the reliability of its network. Although we do not approve opex on specific categories of opex such as maintenance, the total opex we approve will in part influence the repex Powercor needs to spend during the 2016–20 regulatory control period.
Forecast demand	Forecast demand is related to Powercor's total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
Capital Expenditure Sharing Scheme	The CESS is related to Powercor's total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, and that it

Other component	Interrelationships with total forecast capex
(CESS)	reasonably reflects the capex criteria. As we note in the capex criteria table below, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from Powercor's regulatory asset base. In particular, the CESS will ensure that Powercor bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Powercor can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, Powercor risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	The STPIS is interrelated to Powercor's total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2016–20 regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS. Further, the forecast capex should be sufficient to allow Powercor to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to Powercor systematically under or over performing against its targets.
Contingent project	A contingent project is interrelated to Powercor's total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of Powercor's total forecast capex for the 2016–20 regulatory control period. We did not identify any contingent projects for Powercor during the 2016–20 period.

Source: AER analysis.

6.4.6 Consideration of the capex factors

As we discussed in section 6.3, we took the capex factors into consideration when assessing Powercor's total capex forecast.[47] Table 6.5 summarises how we have taken into account the capex factors.

Where relevant, we also had regard to the capex factors in assessing the forecast capex associated with its underlying capex drivers such as repex, augex and so on (see appendix B).

Table 6.5 AER consideration of the capex factors

Capex factor	AER consideration
The most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient distributor over the relevant regulatory control period	We had regard to our most recent benchmarking report in assessing Powercor's proposed total forecast capex and in determining our alternative estimate for the 2016–20 regulatory control period. This can be seen in the metrics we used in our assessment of Powercor's capex performance.
The actual and expected capex of Powercor during any preceding regulatory control periods	We had regard to Powercor's actual and expected capex during the 2011–15 and preceding regulatory control periods in assessing its proposed total forecast. This can be seen in our assessment of Powercor's capex

47 NER, cll. 6.5.7(c), (d) and (e).

Capex factor	AER consideration
	performance. It can also be seen in our assessment of the forecast capex associated with the capex drivers that underlie Powercor's total forecast capex. For non-network capex, we rely on trend analysis to arrive at an estimate that meets the capex criteria.
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by Powercor in the course of its engagement with electricity consumers	We had regard to the extent to which Powercor's proposed total forecast capex includes expenditure to address consumer concerns that Powercor identified. Powercor has undertaken engagement with its customers and presented high level findings regarding its customer preferences.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing Powercor's proposed real cost escalation factors. In particular, we have not accepted Powercor's proposal to apply real cost escalation for labour.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between Powercor's total forecast capex and total forecast opex in Table 6.4 above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to Powercor	We had regard to whether Powercor's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Powercor's total forecast capex and the application of the CESS and the STPIS in Table 6.4 above.
The extent to which the capex forecast is referable to arrangements with a person other than the distributor that do not reflect arm's length terms	We had regard to whether any part of Powercor's proposed total forecast capex or our alternative estimate is referable to arrangements with a person other than Powercor that do not reflect arm's length terms. We do not have evidence to indicate that any of Powercor's arrangements do not reflect arm's length terms.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We had regard to whether any amount of Powercor's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriately be included as a contingent project.
The extent to which Powercor has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which Powercor made provision for efficient and prudent non-network alternatives as part of our assessment. In particular, we considered this within our review of Powercor's augex proposal.
Any other factor the AER considers relevant and which the AER has notified Powercor in writing, prior to the submission of its revised regulatory proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis.

A Assessment techniques

This appendix describes the assessment approaches we applied in assessing Powercor's total forecast capex. We used a variety of techniques to determine whether the Powercor total forecast capex reasonably reflects the capex criteria. Appendix B sets out in greater detail the extent to which we relied on each of the assessment techniques.

The assessment techniques that we apply in capex are necessarily different from those we apply in the assessment of opex. This is reflective of differences in the nature of the expenditure we are assessing. As such, we use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We set this out in our expenditure assessment guideline, where we stated:[48]

> Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across distributors) when forming a view on forecast unit costs.
>
> Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

Below we set out the assessment techniques we used to asses Powercor's capex.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. The NER requires us to consider the annual benchmarking report as it is one of the capex factors.[49] Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.[50] It allows us to compare the performance of a distributor against its own past performance, and the performance of other distributors. Economic benchmarking helps us to assess whether a distributor's capex forecast represents efficient costs.[51] As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[52]

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and

48 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 8.

49 NER, cl. 6.5.7(e)(4).

50 AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines,* November 2013.

51 NER, cl. 6.5.7(c).

52 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 25.

overall capex efficiency. In general, these measures calculate a distributor's efficiency with consideration given to its inputs, outputs and its operating environment. We considered each distributor's operating environment in so far as there are factors outside of a distributor's control that affect its ability to convert inputs into outputs.[53] Once such exogenous factors are taken into account, we expect distributors to operate at similar levels of efficiency. One example of an exogenous factor we took into account is customer density. For more on how we derived these measures, see our annual benchmarking report.[54]

In addition to the measures in the annual benchmarking report, we considered how distributors performed on a number of overall capex metrics, including capex per customer, and capex per maximum demand. We calculated these economic benchmarks using actual data from the previous regulatory control period.

The results from economic benchmarking give an indication of the relative efficiency of each of the distributors, and how this has changed over time.

A.2 Trend analysis

We considered past trends in actual and forecast capex as this is one of the capex factors under the NER.[55]

Trend analysis involves comparing a distributor's forecast capex and work volumes against historical levels. Where forecast capex and volumes are materially different to historical levels, we seek to understand the reasons for these differences. In doing so, we consider the reasons the distributor provides in its proposal, as well as changes in the circumstances of the distributor.

In considering whether the total forecast capex reasonably reflects the capex criteria, we need to consider whether the forecast will allow the distributor to meet expected demand, and comply with relevant regulatory obligations.[56] Demand and regulatory obligations (specifically, service standards) are key drivers of capex. More onerous standards will increase capex, as will growth in maximum demand. Conversely, reduced service obligations or a decline in demand will likely cause a reduction in the amount of capex the distributor requires.

Maximum demand is a key driver of augmentation or demand driven expenditure. Augmentation often needs to occur prior to demand growth being realised. Hence, forecast rather than actual demand is relevant when a business is deciding the augmentation projects it will require in an upcoming regulatory control period. To the extent actual demand differs from forecast, however, a business should reassess the

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[53] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

[54] AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014.

[55] NER, cl. 6.5.7(e)(5).

[56] NER, cl. 6.5.7(a)(3).

need for the projects. Growth in a business' network will also drive connections related capex. For these reasons it is important to consider how trends in capex (in particular, augex and connections) compare with trends in demand (and customer numbers).

For service standards, there is generally a lag between when capex is undertaken (or not) and when the service improves (or declines). This is important when considering the expected impact of an increase or decrease in capex on service levels. It is also relevant to consider when service standards have changed and how this has affected the distributor's capex requirements.

We looked at trends in capex across a range of levels including at the total capex level, and the category level (such as growth related capex, and repex) as relevant. We also compared these with trends in demand and changes in service standards over time.

A.3 Category analysis

Expenditure category analysis allows us to compare expenditure across NSPs, and over time, for various levels of capex. The comparisons we perform include:

- overall costs within each category of capex
- unit costs, across a range of activities
- volumes, across a range of activities
- asset lives, across a range of asset classes which we use in assessing repex.

Using standardised reporting templates, we collected data on augex, repex, connections, non-network capex, overheads and demand forecasts for all distributors in the NEM. The use of standardised category data allows us to make direct comparisons across distributors. Standardised category data also allows us to identify and scrutinise different operating and environmental factors that affect the amount and cost of works performed by distributors, and how these factors may change over time.

A.4 Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works. We have two predictive models:

- the repex model
- the augex model (used in a qualitative sense)

The use of the repex and augex models is directly relevant to assessing whether a distributor's capex forecast reasonably reflects the capex criteria.[57] The models draw

[57] NER, cl. 6.5.7(c).

on actual capex the distributor incurred during the preceding regulatory control period. This past capex is a factor that we must take into account.[58]

The repex model is a high-level probability based model that forecasts asset replacement capex (repex) for various asset categories based on their condition (using age as a proxy), and unit costs. If we consider a distributor's proposed repex does not conform to the capex criteria, we use the repex model (in combination with other techniques where appropriate) to generate a substitute forecast.

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.[59] The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the distributor over a given period.[60] In this way, the augex model accounts for the main internal drivers of augex that may differ between distributors, namely peak demand growth and its impact on asset utilisation. We can use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a distributor's augex forecast.[61]

For our preliminary decision we have relied on input data for the augex model to review forecast utilisation of individual zone substations to assess whether augmentation may be necessary to alleviate capacity constraints. We use this analysis both as a starting point for our further detailed evaluation and as a cross-check on our overall augex estimate. We have not otherwise used the augex model in our assessment of Powercor's augex forecast.

A.5 Engineering review

We drew on engineering and other technical expertise within the AER to assist with our review of Powercor's capex proposals.[62] We also relied on the technical review of our consultant, Energeia, to assist with our review of distributors' capex proposals. These involved reviewing Powercor's processes, and specific projects and programs of work.

Appendix B discusses in detail our consideration of these reviews in our assessment of Power's capex forecast.

Origin Energy submitted the AER must continue to apply technical assessments in concert with its benchmarking techniques to ensure a prudent balance between asset risk and input costs.[63]

[58] NER, cl. 6.5.7(e)(5).

[59] Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

[60] For more information, see: AER, *Guidance document: AER augmentation model handbook,* November 2013.

[61] AER, *'Meeting summary – distributor replacement and augmentation capex', Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution),* 8 March 2013, p. 1.

[62] AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 86.

[63] Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 13 July 2015, p. 1.

B Assessment of capex drivers

We present our detailed analysis of the sub-categories of Powercor's forecast capex for the 2016–20 regulatory control period in this appendix. These sub-categories reflect the drivers of forecast capex over the 2016–20 period. These drivers are augmentation capex (augex), customer connections capex, replacement capex (repex), reliability improvement capex, capitalised overheads and non-network capex.

As we discuss in the capex attachment, we are not satisfied that Powercor's proposed total forecast capex reasonably reflects the capex criteria. In this appendix we set out further analysis in support of this view. This further analysis also explains the basis for our alternative estimate of Powercor's total forecast capex that we are satisfied reasonably reflects the capex criteria. In coming to our views and our alternative estimate we applied the assessment techniques that we discuss in appendix A.

This appendix sets out our findings and views on each sub-category of capex. The structure of this appendix is:

- Section B.1: alternative estimate
- Section B.2: forecast augex
- Section B.3: forecast customer connections capex, including capital contributions
- Section B.4: forecast repex
- Section B.5: Victorian Bushfires Royal Commission
- Section B.6: forecast capitalised overheads
- Section B.7: forecast non-network capex.

In each of these sections, we examine sub-categories of capex which we include in our alternative estimate. For each such sub-category, we explain why we are satisfied the amount of capex that we include in our alternative estimate reasonably reflects the capex criteria.

B.1 Alternative estimate

Having examined Powercor's proposal, we formed a view on our alternative estimate of the capex required to reasonably reflect the capex criteria. Our alternative estimate is based on our assessment techniques, explained in section 6.3 and appendix A. Our weighting of each of these techniques, and our response to Powercor's submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in appendix B.

We are satisfied that our alternative estimate reasonably reflects the capex criteria.

B.2 Forecast augex

Powercor proposed a forecast of $362.3 million ($2015) for augmentation capex (augex), excluding overheads. This is a 67 per cent increase compared to actual augex incurred in the 2011–15 regulatory control period.

Augmentation is typically triggered by the need to build or upgrade the network to address changes in demand and network utilisation. However, it can also triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

As set out in Table 6.6, Powercor's proposed augex forecast is comprised of capex to meet demand and capex for non-demand drivers of expenditure. Powercor's augex forecast is comprised of several identifiable projects and programs, including new and upgraded zone substations, distribution feeder works and voltage regulation.

Table 6.6 Powercor's proposed augex ($2015, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Demand	41.6	42.0	43.8	40.4	27.2	195
Non-demand	18.7	22.2	14.1	13.8	14.4	83.1
VBRC	27.5	15.5	14.1	14.4	13.6	84.2
Total augex proposal	87.8	79.7	72.0	68.6	55.2	362.3

Source: Powercor reset RIN; Powercor regulatory proposal; Powercor response to AER Powercor 019.

Note: The annualised augex in this table differs from Powercor's reset RIN. The augex proposal in this table is based on the bottom-up build of the individual components of Powercor's forecast, based on costing information provided by Powercor in its regulatory proposal and in response to an information request. Numbers may not add up due to rounding.

Our estimate of required augex for Powercor for the 2016–20 period is $241.6 million ($2015), which is 43 per cent less than Powercor's proposal. This is primarily based on our finding that Powercor's forecast for maximum demand likely does not reasonably reflect a realistic expectation of demand over the 2016–20 period. Accordingly, we are not satisfied that Powercor's proposed forecast augex reasonably reflects the capex criteria.

We have formed this view by reviewing all of the material submitted by Powercor in its regulatory proposal and in response to requests for further information, and submissions from stakeholders. Our review used a combination of top-down and bottom-up assessment techniques to estimate the efficient and prudent capex that Powercor will require to meet its obligations given expected demand growth and other augmentation drivers. This is consistent with the overall approach set out in our Expenditure Forecast Assessment Guideline.[64]

First, we considered Powercor's proposed expenditure for demand-related capex in the context of past expenditure, demand and current network utilisation.[65] This trend analysis constitutes our top-down review. As set out in appendix C, we found that Powercor's forecasts of maximum demand do not reasonably reflect a realistic expectation of demand over the 2016–20 period. The available evidence suggests that maximum demand will remain generally flat over the 2016–20 period, which is consistent with the Australian Energy Market Operator's (AEMO) independent forecasts for Powercor's network.

On this basis we consider that Powercor's forecasts of network utilisation over the 2016–20 period are overstated. As set out further in section B.2.1, we observe that, by adopting a more realistic demand forecast, Powercor's forecasts for network utilisation over the 2016–20 period may be broadly similar to that experienced over the 2011–15 period. Powercor spent $101.7 million over 2011–15 to augment its network to alleviate capacity constraints in response to demand. This provides an initial and high-level indication of the prudent and efficient amount for Powercor to meet forecast demand and alleviate capacity constraints over the 2016–20 period.

Second, we undertook a bottom-up review of Powercor's demand-driven forecast by conducting more detailed technical reviews of Powercor's forecasting framework and its major demand-driven projects and programs. This informs our top-down review by assessing whether Powercor used processes that would derive efficient design, costs and timing for each project.[66] In undertaking these technical reviews, we draw on engineering and other technical expertise within the AER.

Based on our technical project review, we formed an alternative bottom-up estimate of the augex required to meet a realistic expectation of demand. This includes making necessary adjustments to individual projects or programs so that the project costs reflect prudent and efficient costs.[67] We found that our bottom-up review produced an alternative augex forecast of $99.9 million ($2015). This is consistent with our top-down estimate of $101.7 million for demand-related augex. On this basis, we consider that $101.7 million reasonably reflects a prudent and efficient amount for Powercor to meet a realistic expectation of demand, and we have included this within our substitute estimate. This is a reduction of around 47 per cent from Powercor's proposal for demand-related augex.

Third, we undertook a technical review of Powercor's major non-demand projects. We focused primarily on capex associated with the Deer Park terminal station and the

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64 AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, p. 82.

65 This is supported by the AER's augex model to generate trends in asset utilisation. We have not otherwise used the augex model to estimate forecast augex.

66 AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, p. 128.

67 AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, p. 128.

voltage regulation program. On the basis of this review, we consider that an alternative estimate of $55.4 million (one third less than proposed) satisfies the capex criteria for these non-demand projects. We have therefore included this amount in our substitute estimate.

Our project reviews and detailed bottom-up estimates for demand and non-demand augex is set out in section B.2.2.

Finally, we reviewed Powercor's proposed capex related to the Victorian Bushfires Royal Commission (VBRC) recommendations. This is set out in appendix B.5. For the reasons set out in that appendix, we consider that Powercor's proposed capex related to the VBRC reasonably reflects the capex criteria and therefore we include it in our alternative estimate.

It is important to note that our overall capex decision does not approve or reject funding for individual projects. Rather, as set out in our Expenditure Forecast Assessment Guideline, we conduct technical project reviews to help us assess the efficient overall capex required for network augmentation, in conjunction with other techniques such as trend analysis.[68] For this particular decision, we have used technical analysis to inform our alternative bottom-up augex estimate, which we have then compared against our top-down estimate. Within the overall capex and revenue allowance we provide in this preliminary decision, it is up to Powercor to allocate its capital and operating budget to meet its obligations (including as circumstances change over time).

Table 6.7 sets out our overall alternative estimate of Powercor’s augex forecast, including the differences between our alternative estimate for demand and non-demand related augex.

Table 6.7 AER's alternative estimate of augex ($2015, million)

	2016	2017	2018	2019	2020	Total
Powercor augex forecast	87.8	79.7	72	68.6	55.2	362.3
AER adjustment for demand-related augex	-15.8	-14.1	-21.1	-26.8	-15.5	-93.3
AER adjustment for non-demand-related augex	-5.5	-5.5	-5.5	-5.5	-5.5	-27.4
Alternative estimate	66.5	60.1	45.4	36.3	34.2	241.6
Difference	-35.2%	-30.5%	-46.0%	-59.6%	-50.4%	-43.4%

Source: AER analysis.

Note: The annualised augex in this table is different from Powercor’s reset RIN and our capex model for Powercor. Our alternative estimate, and the difference to Powercor’s proposal, is based on the bottom-up build of the

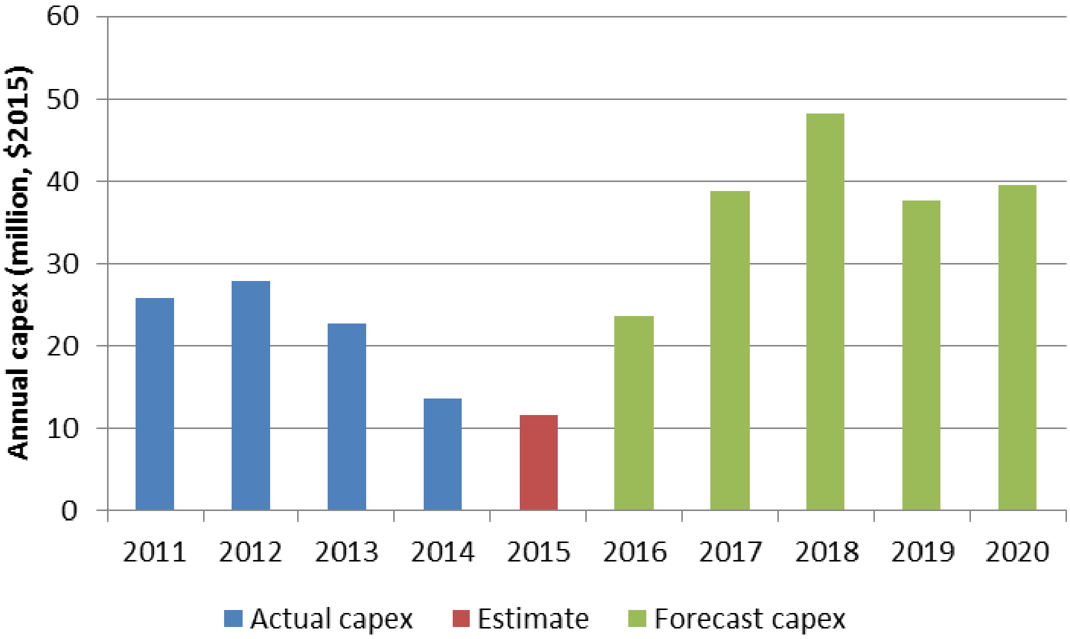
68 AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, pp. 128–130.

individual augex components. The alternative estimate in our capex model is based on applying the 43.4 per cent difference to each year of Powercor's augex forecast as contained in its reset RIN.

B.2.1 Trend analysis

The largest component of Powercor's augex forecast is $195 million ($2015) for demand-driven augex (excluding overheads). Figure 6.7 shows that Powercor's demand-driven augex is 90 per cent higher compared to its actual demand-driven augex in the 2011–15 regulatory control period, which was $101.7 million ($2015).

Figure 6.7 Powercor's demand-driven capex historic actual and proposed for 2016–20 period ($2015, million, excluding overheads)



Source: AER analysis, Powercor's reset RIN, Powercor's response to AER Powercor 002.

The key driver of Powercor's demand-driven augex proposal is forecast growth in maximum demand.[69] Powercor proposed a number of augmentation projects, including new zone substations at Torquay and Truganina, upgrades to capacity in the Geelong East and Merbein zone stations, and high voltage feeders upgrades.[70] The proposed demand-driven augex for 2016–20 is approximately 9 percent of Powercor's proposed capex program.[71]

69 Powercor, *Response to information request AER Powercor IR# 002*, 18, 22 and 26 June 2015.

70 Powercor, *Regulatory Proposal 2016–2020*, Appendix E, April 2015, p. 86.

71 Powercor, *Regulatory Proposal 2016–2020*, Appendix E, April 2015, p. 5; Powercor, *Response to information request AER Powercor IR# 00*2, 18, 22 and 26 June 2015.

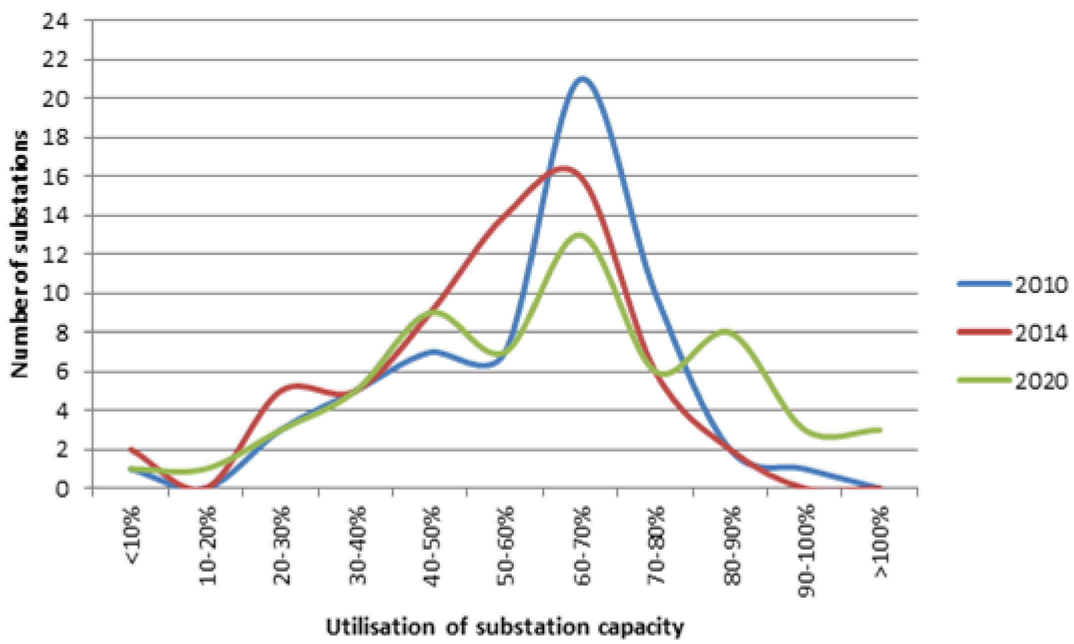
Powercor forecast relatively high growth in maximum demand over the 2016–20 period. As set out in Appendix C, we consider that the available evidence points to flatter demand growth for the 2016–20 period. This suggests that Powercor's demand-driven augex will be overstated when compared to a more realistic expectation of demand over the 2016–20 period.

To examine the impact of a maximum demand on the need for network augmentation, we then look at network utilisation. Network utilisation is a measure of the installed network capacity that is in use (or is forecast to be). Where utilisation rates are shown to be declining over time (such as from a decline in maximum demand), it is expected that total augex requirements will similarly fall.

Figure 6.8 shows Powercor's zone substation utilisation between 2010 and 2014, and forecast utilisation in 2020 (at the end of the regulatory control period). Between 2010 and 2014 Powercor undertook zone substation augmentation, which is shown in a decrease in the number of substations operating above 60 per cent of their maximum capacity. The flattening of maximum demand between 2010 and 2014 also contributed to reduction in the utilisation of the network. As of 2014, there are no substations operating above their maximum capacity.

The forecast of zone substation utilisation in 2020 is based on Powercor's forecast demand at each substation and existing levels of capacity (without additional augmentation). The increase in the number of highly utilised zone substations (above 80 per cent utilisation) reflects Powercor's expectations on demand growth between 2015 and 2020 (shown in Figure 6.8 as a shift to the right in network utilisation forecast in 2020).

Figure 6.8 Powercor zone substation utilisation 2010 and 2014 actual, and 2020 forecast



Source: AER analysis, Powercor's reset RIN.

Note: The utilisation rate is the ratio of maximum demand and the thermal rating of each feeder for the specified years. Forecast utilisation in this figure is based on forecast weather corrected 50% POE maximum demand at each substation and existing capacity without additional augmentation over 2016–20.[72]

We expect that Powercor will be able to maintain current levels of network utilisation over the 2016–20 period. We accept that there will likely be parts of Powercor's network that require augmentation due to localised demand growth (as we discuss further below), to the extent that the number of highly utilised sub-stations may increase. However, the forecast increase in network utilisation by 2020 is likely significantly overstated, which suggests that its augex forecast is similarly overstated.

As stated above, Powercor's forecast network utilisation is driven by its forecast of relatively high growth in maximum demand over the 2016–20 period. In reality, the available evidence points to flatter demand growth for the 2016–20 period, as we discuss in Appendix C. When we apply a realistic and flatter demand forecast for Powercor, this will mean that current levels of network utilisation will remain overall. We accept that there will likely be parts of Powercor's network that require augmentation due to localised demand growth (as we discuss further below), to the extent that the number of highly utilised zone sub-stations may increase. However, the general flattening of demand should mean that Powercor's forecast increase in network utilisation by 2020 is likely to be significantly overstated, which suggests that its augex forecast is similarly overstated.

Similar levels of demand growth were experienced, on average, over the 2011–15 period. Over this period, Powercor spent $101.7 million to augment its network to alleviate capacity constraints, which is evident in the overall decrease in network utilisation between 2010 and 2014 in Figure 6.8. This gives us a high-level indicator of the likely quantum of capex Powercor may require to augment its network over the 2016–20 period.

We have also reviewed some of the specific substations that Powercor proposes to augment in the 2016–20 period. We have reviewed the forecast utilisation at these substations to assess whether augmentation may be prudent based on alleviating capacity constraints. The VECUA supported this approach in its submission that stated:

> The AER needs to determine the distributors' augmentation capex needs utilising credible demand forecasts at the zone substation level and taking into account local system utilisation and excess capacity levels.[73]

Table 6.8 shows the forecast utilisation (without augmentation) for the Geelong East, Melton and Merbein zone substations, and the zone substations that will have their

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[72] We have used Powercor's 'Transformer Normal Cyclic Total' reported in its Reset RIN, rather than using the reported 'Substation Normal Cyclic' rating. Powercor report that the substation normal cyclic rating reported is not the maximum cyclic rating the substation can support, as it runs zone substations based on their ability to withstand contingency events. See Powercor, *2014 Reset RIN basis of preparation*, p. 26.

[73] Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 25.

load reduced with the construction of zone substations at Truganina and Torquay. These figures show that, based on Powercor’s demand forecasts, utilisation is expected to significantly increase over the period in all substations.

Table 6.8 Utilisation of zone substations affected by augmentation

Zone substation	2015	2020
Geelong East	0.97	1.17
Merbein	0.82	1.01
Melton	0.76	0.91
Bacchus Marsh	0.71	0.85
Laverton	0.75	0.91
Laverton North	0.74	0.91
Sunshine	0.67	0.79
St Albans	0.73	0.82
Werribee	0.73	0.88
Waurn Ponds	0.80	1.08

Source: AER analysis, Powercor’s Reset RIN.

On the basis of this analysis, we can make some observations about the need to augment network capacity based on Powercor's maximum demand forecasts at the zone substation level and realistic demand forecasts (based on the reasoning set out in Appendix C):

- The forecast utilisation of the Geelong East substation will be over capacity by 2020. This indicates that augmentation should be required to ease load pressures. Because significant capacity constraints already exist at this zone substation, augmentation will likely still be required under a lower demand forecast (which is considered further in section B.2.2).
- The forecast utilisation of the Merbein substation will be approximately at capacity by 2020. This indicates that augmentation will likely be required at some point to ease load pressures. Because capacity constraints already exist at this zone substation and localised demand growth in the region, augmentation will likely still be required under a lower demand forecast (which is considered further in section B.2.2).
- The forecast utilisation of zone substations around the west of Melbourne (Laverton, Sunshine, St Albans and Werribee) is expected to increase over the 2016–20 period. The forecast load at these zone substations will decrease after the construction of the proposed Truganina zone substation. This suggests that some augmentation may be required to ease load pressures. Under lower demand forecasts, the extent to which capacity constraints will exist is not clear, and

therefore more detailed technical project analysis may be required. We consider this in section B.2.2.

We understand that Powercor is in the process of updating its demand forecasts as part of drafting its 2015 distribution annual planning report. We also note that AEMO will publish updated connection point demand forecasts for Victoria. As we state in Appendix C, we will consider updated demand forecasts and other information (such as AEMO's updated connection point forecasts) in our final decision to reflect the most up to date data.

We have considered the potential impact of adopting more realistic demand forecasts in our review of Powercor's major augex projects and programs in section B.2.2.

A number of submissions commented on network utilisation:

- The Consumer Challenge Panel submitted that Powercor's existing utilisation data and declining peak demand supports a view that there is little need for augmentation capex.[74] The CCP accepted that each Victorian distributor identifies that there are pockets of demand growth in its network that require augmentation. However, it also noted that there are also pockets of declining usage, meaning there is the potential to utilise assets no longer needed in some parts of the network and relocate them to where growth is being experienced.[75]
- The VECUA and the Victorian Greenhouse Alliances also submitted that there were significant investments in the Victorian networks over recent regulatory control periods which has led to excess levels of network capacity and declining network utilisation.[76] Both submitted that we should consider this evidence closely in our capex assessment.

As noted by these stakeholders, we agree that current levels of network utilisation are important factors to consider in reviewing augmentation requirements over time. However, in terms of determining a level of augex for the 2016–20 period, it is also necessary to consider future demand and forecast network utilisation over this period. We considered this above.

We note the comments of CCP in relation to the ability to relocate assets. Advice from our technical and engineering staff suggests that it is generally not technically or economically feasible to relocate distribution assets to other parts of the network to any significant degree. We understand that any ability to relocate assets would be limited and would not impact materially on the required expenditure for the 2016–20 period.

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74 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, p. 17.

75 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, p. 17.

76 Victorian Energy Consumer and User Alliance, ***Submission to the AER Victorian Distribution Networks' 2016–20*** *Revenue Proposals*, 13 July 2015, p. 4 and 22–24; Victorian Greenhouse Alliances, *Local Government Response to the Victorian Electricity Distribution Price Review 2016–20* , 13 July 2015, pp. 33–34.

The remaining component of Powercor's augex forecast is $83.1 million ($2015) for non-demand related augex (excluding overheads). This is 50 per cent more than the actual non-demand augex that Powercor spent during the 2011−15 regulatory control period. This is primarily driven by augex associated with the Deer Park terminal station and a voltage regulation program. These capex projects are not primarily driven by forecast maximum demand and network utilisation; hence we have assessed these projects through more specific technical analysis.

B.2.2 Project and program reviews

We have examined Powercor's major augmentation projects and planning approach to assess whether they reflect the efficient costs that a prudent operator would require to achieve the capex objectives. In particular, we reviewed Powercor's Truganina, Torquay, Merbein and Geelong East zone substation projects, the Deer Park terminal station project, and the high voltage feeders and voltage compliance programs. On the basis of our analysis, we then formed an alternative bottom-up estimate of the prudent and efficient capex required for augmentation.

As part of our review, we first considered Powercor's governance and forecasting process to assess how it goes about making investment and operational decisions. As set out in our Expenditure Forecast Assessment Guideline, we considered:[77]

- The identified need for the project in terms of satisfying the capex objectives in the NER (in particular meeting a realistic expectation of demand forecasts)
- Powercor's network planning methodology and criteria to consider whether it reflects good industry practice to determine if the proposed costs are consistent with incurring efficient and prudent expenditure
- Powercor's cost-benefit analysis and options analysis, including considering non-network options to prudently defer major augmentation
- The net benefit to consumers from proceeding with Powercor's proposed augmentation projects and programs.

As set out previously, we draw on engineering and other technical expertise within the AER to conduct these assessments.

On the basis of our review, we are satisfied that Powercor's forecasting approach reflects good industry practice. This is because Powercor applies cost-benefit and probabilistic network planning methods to its sub-transmission and zone substation augmentation projects that take into account VCR. This is a risk based economic approach to network planning in which Powercor's compares the forecast cost to consumers from losing energy supply that may be avoided by augmentation expenditure (e.g. when demand exceeds available capacity) against the proposed cost

[77] AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, pp. 81–83, 84–86, 167–168.

to augment capacity. The annual cost to consumers is calculated by multiplying the expected un-served energy (e.g. the expected energy not supplied based on probability of supply constraint occurring in a year) by VCR. This is then compared with the annualised augmentation solution cost.

However, we consider that Powercor's proposed augex need is overstated because:

- the VCR it uses for some of its augmentation cost-benefit analyses is outdated and likely overstated
- its forecasts of maximum demand for the 2016–20 period likely overstate demand compared to a more realistic expectation of demand.

Powercor's submission stated that it has adopted AEMO's 2014 Victorian VCR estimate for its augex forecast in its regulatory proposal. AEMO's 2014 VCR for Victoria is $39,500 ($/kWh), which is significantly lower than previous values estimated for 2013.[78] Powercor submits that:

> The large reduction in the AEMO VCR values between 2013 and 2014 resulted in the deferral of some anticipated projects from the 2016–2020 regulatory control period to 2021 and beyond. This includes the deferral of the planned new 66kV switching station at Hexham and a new sub-transmission line from Numurkah to Cobram East zone substation.[79]

While Powercor stated in its proposal that it adopted AEMO's 2014 Victorian VCR estimate, some of its augmentation project planning documents and supporting information indicates that it has applied the higher 2013 VCR estimates. In particular, some of its regulatory investment test documents for its proposed zone substation augmentation projects adopt a VCR of $67,800 ($/kWh) or greater, which is 70 per cent higher than AEMO's 2014 estimate.[80] Powercor's augmentation planning documents were prepared prior to the release of AEMO's 2014 VCR estimates in December 2014 which likely explains why it adopted a higher VCR. However, it is not clear whether Powercor has reconsidered all of its augmentation requirements in light of the publication of AEMO's 2014 VCR estimate.

As set out in Appendix C and above, we also consider that Powercor's demand forecast is overstated. The available evidence points to flatter demand growth for the 2016–20 period than forecast by Powercor, which is consistent with the independent demand forecast from AEMO. However, demand growth is not consistent across Powercor's network and there may be pockets of higher demand growth on the network which support some augmentation.

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[78] AEMO, Value of Customer Reliability Review, Final Report, September 2014.

[79] Powercor, *Regulatory Proposal 2016–20*, Appendix E, April 2015, p. 68.

[80] See Powercor, *Regulatory Proposal 2016–20*, Appendix E.37, April 2015, p. 9 and 22; Powercor, *Regulatory Proposal 2016–20*, Appendix E.37, April 2015, p. 9 and 22; Powercor, *Regulatory Proposal 2016–20*, Appendix E.38, April 2015, p. 10; Powercor, *Regulatory Proposal 2016–20*, Appendix E.39, April 2015, p. 7; Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 16.

We have considered the impact of a lower VCR and lower demand forecasts on Powercor's augmentation requirements in our review of each major project and program. This is set out in the sections below.

On the basis of our analysis, we then formed an estimate of the prudent and efficient capex for each of the augex projects and programs we reviewed. This analysis forms the basis for our alternative bottom-up estimate of Powercor's total augex requirements for the 2016–20 period. This is shown in Table 6.9.

Table 6.9 AER alternative estimate of Powercor's major augex projects and programs ($2015, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Demand	**23.1**	**28.3**	**14.4**	**19.8**	**14.2**	**99.9**
Truganina new zone substation	5.4	8.9	0.2	0.0	0.0	14.5
Torquay new zone substation	0.0	0.0	0.0	0.0	0.0	0.0
Geelong East zone substation upgrade	3.5	5.2	0.0	0.0	0.0	8.7
Merbein zone substation upgrade	0.0	0.0	0.0	5.5	0.0	5.5
HV feeder upgrades	8.9	8.9	8.9	8.9	8.9	44.6
LV feeders and distribution transformers	0.9	0.9	0.9	0.9	0.9	4.4
Other augmentation projects	4.4	4.4	4.4	4.4	4.4	22.2
Non-demand	**13.2**	**16.7**	**8.6**	**8.3**	**8.9**	**55.8**
Deer Park Terminal Station augex	6.8	9.3	0.3	0.0	0.0	16.4
Voltage regulators	0.0	0.0	0.0	0.0	0.0	0.0
SCADA	5.6	6.7	7.5	7.5	8.2	35.5
Other non-demand	0.8	0.8	0.8	0.8	0.8	3.9
Total augex proposal	36.3	45.0	23.0	28.1	23.2	155.7

Source: AER analysis; Powercor regulatory proposal; Powercor response to AER Powercor 19.

Note: Numbers may not add up due to rounding.

Truganina zone substation

Powercor proposed $14.4 million to build a new zone substation in the suburb of Truganina, and an additional $8.6 million to install a third transformer in this zone substation by 2019. This new zone substation is proposed to meet expected increases in demand in the Western Melbourne growth area, and relieve capacity constraints in the surrounding suburbs.

Truganina and the surrounding suburbs currently served by substations at St Albans, Werribee, Laverton, Laverton North and Sunshine. As set out previously, these substations are forecast to be relatively highly utilised by 2020 without any augmentation (using normal cyclic capacity). Powercor submitted that these zone substations are already operating above their emergency n-1 capacity (i.e. the available capacity if there is a loss of a single transformer).[81]

Powercor forecast demand growth at the Western Melbourne zone substations will be around 20 per cent over the 2016–20 period. As set out in Appendix C, we consider that demand growth will likely be significantly flatter than forecast by Powercor across its network. However, we recognise that demand growth is not equal across the network and there will be areas of higher growth and low growth (or even negative growth).

One driver of differences in demand growth will be differences in population growth. In the Western Melbourne growth area, the City of Wyndham (the local council for Truganina and Werribee)[82] and the City of Brimbank (the local council for the other zone substation)[83] forecasts population growth over 2016–20 period between 12 per and 43 per cent. We consider that the existence of significant forecast population growth in these areas supports higher demand growth than the system average.

As set out above, Powercor employs a probabilistic approach to augmentation planning. This involves modelling the expected cost to consumers from losing energy supply (e.g. when demand exceeds available capacity) if a project does not proceed. This is then compared to the proposed cost to augment capacity to determine whether the project reflects the efficient costs to address expected outages and losses of energy supply.

Given Powercor's own demand forecasts, it calculated that the cost to consumers from expected unserved energy due to network outages and capacity constraints will be $19.5 million if the new zone substation is not built by 2023.[84] In the event of the failure of one transformer, the cost to consumers will increase significantly to $27 million in 2020 and $54 million in 2023.[85] This exceeds Powercor's proposed $14.4 million cost to build the Truganina substation. Even under a slightly lower demand forecast, Powercor's proposal reasonably reflects the prudent and efficient costs to meet forecast demand growth and alleviate capacity constraints in the Western Melbourne growth area.

We note that Powercor's planning documentation calculates its proposed costs to consumers using the 2013 VCR estimate, which is higher than AEMO's 2014 estimate. Because AEMO's 2014 VCR estimate is approximately 40 per cent lower than Powercor's estimate, this means that applying AEMO's 2014 estimate will reduce the

81 Powercor, *Regulatory Proposal 2016–20*, Appendix E.37, April 2015, p. 14.

82 See http://forecast.id.com.au/wyndham/dwellings-development-map?WebID=170.

83 See http://forecast.id.com.au/brimbank/dwellings-development-map?WebID=290.

84 Powercor, *Regulatory Proposal 2016–20*, Appendix E.37, April 2015, p. 14.

85 Powercor, *Regulatory Proposal 2016–20*, Appendix E.37, April 2015, p. 14.

cost to consumers from a power outage by up to 40 per cent. It is not clear whether Powercor has reconsidered its cost-benefit analysis in light of AEMO's 2014 VCR.

While adopting a lower VCR will lower the expected costs to consumers if the new substation is not built, the unserved energy cost to consumers is still significantly greater than the cost of the proposed augmentation work. On this basis, we are satisfied that the construction of a new zone substation remains a prudent and efficient option.

Powercor submitted that the forecast demand at the new Truganina zone substation is expected to exceed its emergency n-1 capacity by 2020.[86] On this basis, it proposes to install a third transformer by 2019. We are not satisfied that the construction of a third transformer by 2019 reflects the prudent and efficient option to alleviate future capacity constraints at this substation. This is because:

- The proposed cost of the third transformer is 64 per cent of total cost to construct the Truganina zone substation. Given that civil works are already covered in the initial construction, this cost seems excessive and may not reflect the efficient costs to install a new transformer.
- Powercor estimated the value of unserved energy based on a 2013 VCR.[87] After applying the AEMO's 2014 VCR, we found the risk to consumers could not justify the cost of the third transformer before 2021.

Powercor also considered the cost of demand management as an alternative to installing a third transformer. Based on Powercor's documentation, it estimated that demand management will cost approximately $1.5 million per year, which exceeds the per annum cost of installing the third transformer.[88] On this basis, Powercor dismissed the option of utilising demand management. However, Powercor's proposed cost of demand management is calculated by considering substation capacity in Truganina when there is the loss of a single transformer. We have undertaken a technical review, drawing on internal engineering and technical expertise, and consider that because the existing transformers in the Truganina zone substation are newly installed the total loss of one of these transformers is extremely unlikely. Because Powercor's demand management cost estimate did not factor in the very low likelihood of transformer failure, the expected cost of demand management is therefore likely overstated.

On the basis of our analysis, we have included capex for the new Truganina zone substation in our alternative bottom-up estimate because the capex reflects a prudent and efficient amount for Powercor to meet demand growth and alleviate capacity constraints. However, we are not satisfied that the construction of a third transformer by 2019 reasonably reflects the prudent and efficient option to alleviate future capacity constraints at this substation. Powercor may also be able to efficiently defer the need for a third transformer through demand management activities.

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[86] Powercor, *Regulatory Proposal 2016–20*, Appendix E.66, April 2015, p. 3.

[87] Powercor, *Regulatory Proposal 2016–20*, Appendix E.37, April 2015, p. 22.

[88] Powercor, *Regulatory Proposal 2016–20*, Appendix E.66, April 2015, p. 4.

Geelong East zone substation upgrade

Powercor proposed $8.7 million to upgrade the Geelong East zone substation to meet expected demand growth and existing alleviate capacity constraints at this zone substation.

As set out above, the Geelong East zone substation is forecast to significantly exceed its normal operating capacity by 2020. Powercor stated that is currently operating above its emergency n-1 capacity (i.e. the available capacity if there is a loss of a transformer).[89] In addition, Powercor submits that:

> Limited load transfer capability exists between GLE [Geelong East] zone substation and three neighbouring zone substations. As a result, customers could potentially be left without supply until capacity in the neighbouring network becomes available for supply to be restored.[90]

Powercor forecast demand growth at the Geelong East zone substation will be around 20 per cent over the 20156–2020 period (or 4 per cent per annum). As set out in Appendix C, we consider that demand growth will likely be flatter than forecast by Powercor across its network. The City of Greater Geelong's population forecast for 2016–2021 averages 1.8 per cent per annum.[91] This also suggests that maximum demand may be less than forecast by Powercor.

While demand growth in the Geelong East region may be less than forecast by Powercor, existing capacity constraints mean that a small increase in demand may risk a loss of supply to consumers (in particular if there is a loss of single transformer). In the event of the failure of one transformer, Powercor calculates that the cost to consumers from expected unserved energy from network outages at the Geelong East zone substation will be $290 million in 2017 without any augmentation.[92] This significantly exceeds the proposed $8.7 million to upgrade the Geelong East zone substation. On this basis, Powercor's proposal reflects the prudent and efficient costs to alleviate capacity constraints in East Geelong.

We note that in reality the forecast unserved energy cost will likely be lower than estimated by Powercor. Powercor calculates the cost to consumers using a VCR of $77,000 ($/kWh), which is based on the 2013 VCR estimates.[93] Applying AEMO's 2014 VCR estimate will reduce the cost to consumers from a power outage by up to 40 per cent. In addition, Powercor has not considered the potentially low probability of transformer failure in its cost-benefit analysis which also inflates the expected costs to consumers.

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89 Powercor, *Regulatory Proposal 2016–20*, Appendix E.39, April 2015, p. 3.

90 Powercor, *Regulatory Proposal 2016–20*, Appendix E.39, April 2015, p. 3.

91 See http://forecast.id.com.au/geelong?WebID=190.

92 This is based on Powercor's 50 PoE demand forecasts for the Geelong East zone substation, at n-1 capacity.

93 This estimate is higher than the $67,800 ($/kWh) applied to other proposals. Powercor's VCR for Geelong East includes a higher proportion of commercial and industrial demand to reflect the customer base in this area.

However, even after accounting for a lower demand forecast and a lower probability of transformer failure and applying AEMO's 2014 VCR estimate, we found the benefit of augmentation still exceeded the cost. On the basis of this analysis, we have included capex to upgrade the Geelong East zone substation in our alternative bottom-up estimate because the capex reflects a prudent and efficient amount for Powercor to alleviate capacity constraints in Geelong East.

Merbein zone substation upgrade

Powercor proposed $5.5 million to upgrade the Merbein zone substation in 2016. This zone substation serves residential, commercial and agricultural customers in the Mildura area of Victoria. The upgrade is proposed to meet forecast demand and alleviate capacity constraints at the Merbein and Mildura zone substations.

As set out above, the Merbein zone substation is forecast to operate at its normal operating capacity by 2020. Powercor submits that it is currently operating above its emergency n-1 capacity.[94] This suggests that augmentation may be required to address the risk of a loss of energy supply to customers.

Given Powercor's demand forecasts, it calculates that the cost to consumers from expected unserved energy from network outages will be up to $2.5 million by 2020.[95] As with some of Powercor's other augmentation projects, it adopts its 2013 VCR estimate to calculate the cost to consumers. If we adopt AEMO's 2014 Victorian VCR, we calculate that this reduces the cost to consumers to approximately $1.3 million in 2020.

Powercor calculated that the annualised cost of upgrading the Merbein zone substation will be $456,000.[96] This is less than the $1.3 million annual cost to consumers from a loss of energy supply in 2020. On this basis, Powercor's proposal reflects the prudent and efficient costs to meet forecast demand growth and alleviate capacity constraints.

Powercor forecast demand growth at the Merbein zone substation will be around 22 per cent over the 2015-2020 period. As set out in Appendix C, we consider that demand growth will likely be flatter than forecast by Powercor across its network. However, AEMO's demand forecast at the local Red Cliff terminal station predicts 16 per cent growth in demand over the 2015–20 period, which is only 6 per cent lower than Powercor's forecasts. This suggests that the need for augmentation might be deferred to later in the 2016–20 regulatory control period, but not avoided altogether.

On the basis of our analysis, we have included capex to upgrade the Merbein zone substation in our alternative bottom-up estimate because the capex reflects a prudent

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94 Powercor, *Regulatory Proposal 2016–20*, Appendix E.38, April 2015, p. 7.

95 This is based on the forecast cost of expected unserved energy at the Merbein and Mildura zone substations, using a 0.7/0.3 weighted average of Powercor's 50 PoE and 10 PoE demand forecasts.

96 The annualised cost reflects the annual costs faced by consumers for this project. This is calculated based on the annual depreciated cost of the project and the cost of capital required.

and efficient amount for Powercor to meet demand growth and alleviate capacity constraints. Based on a slightly reduced demand forecast, we consider that the need for augmentation at the Merbein substation can be prudently deferred until later in the 2016–20 period. However it is ultimately Powercor's responsibility to determine the precise timing of this project within the 2016–20 period.

Torquay zone substation

Powercor proposed $20.7 million to build a new zone substation in Torquay. This new zone substation is proposed to meet demand growth, alleviate capacity constraints at the existing Waurn Ponds zone substation, and manage voltage issues in the Torquay and Surf Coast region.[97]

As set out above, the Waurn Ponds zone substation is forecast to operate above its normal operating capacity by 2020. Powercor submitted that it is currently operating above its emergency n-1 capacity (i.e. the available capacity if there is a loss of a transformer).[98] This suggests that augmentation may be required at some point to address the risk of a loss of energy supply to customers.

Powercor forecast demand growth at the Waurn Ponds zone substation will be around 34 per cent over the 2016–20 period. Under this forecast, the potential for demand to exceed capacity may increase significantly over the next regulatory control period. However, we are not satisfied that this demand forecast is realistic for the following reasons:

- AEMO's demand forecast for the Geelong Terminal Station (which serves the Waurn Ponds zone substation and Surf Coast region) only predicts 1 per cent demand growth over the 2015–20 period.[99]
- The City of Greater Geelong only forecasts 2.4 per cent population growth in Waurn Ponds over the 2016–2021 period, which does not suggest that population growth will support significant increases in maximum demand.[100]
- There will be significant growth in the local Armstrong Creek region over the next 20 years due to residential development. However, Powercor states that this growth is expected to be served by the Geelong East zone substation rather than the Waurn Ponds zone substation.[101]

Given Powercor's demand forecasts, it calculated that the cost to consumers from expected unserved energy from network outages at the Waurn Ponds zone substation

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[97] Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 3.

[98] Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 17.

[99] AEMO actually forecasts negative demand growth over the 2015-20 period. However this includes reductions in block load due to the closure of manufacturing plants in 2016. After accounting for these reductions, AEMO forecasts approximately 1% annual demand growth for the remainder of the 2015-20 period. See AEMO, *Value of Customer Reliability Review*, Final Report, September 2014.

[100] See http://forecast.id.com.au/geelong/population-households-dwellings?WebID=420.

[101] Powercor, *Regulatory Proposal 2016–20*, Appendix E.39, April 2015, p. 9.

will be between $1.4 million and $1.8 million by 2020.[102] The proposed annualised cost of the new Torquay zone substation is $1.33 million, which suggests that the benefit of this project marginally exceeds the cost. However, this calculation is based on Powercor's 2013 estimate of VCR. If instead we adopt AEMO's 2014 Victorian VCR, we calculate that this reduces the cost to consumers (if the new zone substation does not proceed) to approximately $950,000 in 2020, which is less than the proposed annualised cost of the new zone substation.

When we also take into account lower than forecast demand, the cost of unserved energy to consumers falls further, which suggests that building a new zone substation in Torquay in the 2016–20 period does not reasonably reflect the prudent and efficient costs to meet demand growth and alleviate capacity constraints.

Powercor also submitted that the Waurn Ponds 22kV feeders supplying the Surf Coast areas are projected to not meet the voltage standards set out in Victorian Distribution Code by 2018. This Code requires that Powercor maintain voltage levels at +/- 6 per cent on 22kV feeders (and +/- 10 per cent in rural areas).[103]

Powercor submitted that three of its five 22kV feeders supplying Torquay will be below the minimum voltage levels set out in the Code by 2018.[104] Powercor also states that:

> Powercor is currently taking action - including the installation of voltage regulators and high voltage capacitors - to manage voltage issues in the Torquay and Surf Coast area. However, by 2018, such measures will be unable to ensure Powercor's on-going compliance with the minimum voltage requirements prescribed in the Code. There is, therefore, a need for Powercor to take further action.

Powercor proposed that the new Torquay zone substation, and associated feeder works, will allow it to manage voltage levels. This is because:

> Under this option, approximately 30 MVA of load would be transferred from the overloaded WPD [Waurn Ponds] zone substation to the new Torquay zone substation, enabling Powercor to supply customers in the Torquay / Surf Coast area in accordance with the voltage standards specified in the Code.[105]

A common low cost method for correcting feeder voltage drops is to install voltage regulators at the load end of the feeders. Powercor dismissed the option of voltage regulators as an interim solution because "the feeder loads will be too high compared to the standard Powercor regulator."[106] However, advice from our technical and engineering staff suggests that larger regulators are available to handle large loads. This suggests that Powercor may have lower cost solutions at hand for the anticipated voltage problems.

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[102] This is based on Powercor's demand forecasts at 2020 at the 50 PoE and 10 PoE levels, using its 2013 estimates of VCR. See Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 17.

[103] Clause 4.2.2 of the Victorian Distribution Code.

[104] Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 7.

[105] Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 8.

[106] Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 7.

In addition, our analysis of Powercor's own supporting documentation shows that forecast drops in voltage levels on its feeders will be less pronounced under a lower demand forecast.[107] In reality, Powercor will likely experience a lower (potentially significantly lower) rate of growth than it forecasts (for the reasons set out above and in Appendix C), which means it will experience less voltage issues than it expects. On this basis, we consider that Powercor will likely be able to effectively maintain the supply voltage in this region without a new zone substation.

On the basis of our analysis, we have not included any capex for this project in our alternative bottom-up estimate. This is because Powercor's proposed augmentation cost to build the new Torquay zone substation exceeds the benefits delivered to consumers when realistic assumptions of VCR and demand are applied. We also consider that Powercor should be able to effectively manage voltage levels on its feeders over the 2016–20 period through other means including voltage regulators due to lower than forecast demand growth.

Deer Park terminal station augex

Powercor proposed $16.4 million to build sub-transmission lines to connect to the new Deer Park terminal station that is being built by AusNet Services Transmission. This will allow Powercor to transfer load from the Melton and Sunshine zone substations to the Deer Park Terminal Station.

The primary driver of the construction of the Deer Park Terminal Station and Powercor's sub-transmission lines is capacity constraints at the existing Keilor Terminal Station. AEMO, Powercor and Jemena jointly completed a regulatory information test for transmission (RIT-T) in May 2012 for this project. This concluded that a new Deer Park Terminal Station and Powercor zone substation load transfer is the preferred option to address forecast capacity constraints at the Keilor Terminal Station.

We have not assessed the need for the new Deer Park Terminal Station in this decision. The investment in the Deer Park Terminal Station is made by AusNet Services Transmission, rather than Powercor. Powercor's proposed sub-transmission lines will be necessary to allow load transfer to occur immediately after AusNet Services completes the Deer Park Terminal Station construction in 2018. This will maximise the benefit of the combined project by immediately utilising the Deer Park Terminal Station asset capacity.

On this basis, we have included Powercor's proposed capex in our alternative bottom-up estimate because it likely reflects the prudent and efficient costs to maximise the benefits from the construction of the Deer Park terminal station.

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[107] Powercor, *Regulatory Proposal 2016–20*, Appendix E.40, April 2015, p. 8.

HV Feeders

Powercor proposed $107.5 million ($2015, excluding overheads) to augment HV feeders across its network due to demand growth over the 2016–20 period. This is a 130 per cent increase over the $43.5 million Powercor spent over the current 2011–15 period.

Powercor submitted that demand growth continues to drive HV feeder investment through specific growth areas across its networks. These areas include outer western Melbourne, Geelong, Bendigo and Ballarat, with each area exhibiting residential, commercial and industrial load growth.[108] We consider that Powercor did not submit sufficient supporting information to justify an increase in HV feeder augmentation above the historical average. Our assessment has relied on limited information provided by Powercor in response to information requests.[109]

We have included $44.6 million for HV feeders in alternative estimate which we consider reasonably reflect the prudent and efficient amount for Powercor to meet expected demand growth in its network. Our alternative estimate is the average of the actual annual expenditure on HV feeders in the 2011–14 period. We note that Powercor has used this averaging forecasting methodology for its forecasts of gifted assets, rebates and low volume connections work that cost less than $2.5 million.[110]

We forecast limited overall peak demand growth of 0.27 per cent per annum, based on AEMO's demand growth projections as we discuss in Appendix C. In contrast, Powercor forecasts 3.5 per cent annual growth in demand over the 2016–20 period. As peak demand is not expected to grow significantly, we consider an allowance based on actual expenditure will be sufficient for Powercor to augment in areas required to meet localised demand growth.

We also note that:

- Powercor has not justified HV feeder augmentation in some areas, for example in Keilor. This is particularly an issue where feeder augmentation is not linked to zone substation augmentation.
- For some specific feeder augmentations, it appears that funding could be obtained (at least in part) through customer contributions. We have not seen any information to indicate that customer contributions have been considered, despite the feeders being associated with the connection works for individual customers.
- Powercor has not justified its forecast expenditure on voltage regulators to address expected demand-driven voltage issues.
- Some of the proposed expenditure is for feeder ties, which primarily improve reliability under outage conditions rather than satisfy augmentation requirements.

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108 Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015, p. 3.

109 Powercor *Response to AER Information Request Powercor IR# 017*, 30 July 2015.

110 Powercor, *Regulatory Proposal 2016–20*, Appendix E, April 2015, pp. 114–115.

In coming to this position, we have considered a number of Powercor's proposed HV feeder augmentation projects. In the sections below we consider the HV feeder augex proposed for each major zone of the network. We highlight a number of proposed projects that appear justifiable, and those that do not appear to justifiable due to differences in demand forecasts and/or due to a lack of information. We consider the evidence indicates that Powercor may need to augment feeders in some areas, but it doesn't justify expenditures incremental to those approved for the 2011–15 period. We therefore consider an allowance based on historical expenditure is appropriate.

Geelong

Powercor proposed $18.7 million to augment HV feeders in the Geelong areas. Some of these feeders are associated with Powercor's proposed new and upgraded zone substation in the Greater Geelong and Surf Coast area that are serviced by the Geelong Terminal Station.

We observe that the following proposed HV feeders could be deferred:[111]

- TQY 5th Feeder - Messmate Road. We consider this feeder can be delayed until the following regulatory control period, consistent with our position that the Torquay zone substation can be delayed.
- GLE22 – a new 22kV feeder to Armstrong Creek. We also consider this feeder can be delayed until the following regulatory control period, consistent with our position that the Torquay zone substation can be delayed.
- WPD14 – an alternate route to a customer line. This is to construct a new feeder to replace the existing feeder that shares a customer line. Powercor has not provided supporting information or underlying drivers to justify this feeder.
- GL13 – a new feeder to Bannockburn. Powercor state the feeder is to allow for future load growth and secure higher levels of contingency transfers during unplanned outages.[112] It adds that it will be built at 66kV and will be used to supply a future zone substation at Bannockburn (BBN). We consider this feeder is not warranted as:
    - the forecast load growth is likely overstated;
    - the extra cost of building to 66kV construction is not justified (as it has not explained why a future zone substation is required); and
    - the higher levels of transfers during unplanned outages (for reliability improvement purposes) is not relevant to augex nor separately justified.
- FNS 31 – a new feeder to Lara, and FNS 33 – a new feeder to Heales Rd / Avalon area. Consistent with our position on other feeders affected by the Torquay

[111] Some information sourced from Powercor's augmentation capex model submitted as part of its regulatory proposal.

[112] Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015,, p. 5.

substation, we consider the need for the FNS 33 feeder is likely delayed beyond the 2016–20 period.

The cost of the five deferred feeders amounts to $12.9 million out of $18.7 million, or 60 per cent, of demand-driven feeder augmentation in the Geelong area.[113]

Terang

Powercor has proposed the following new feeders for the Terang area:

- WBL4 feeder to Allansford to support the growing diary load in the area.
- Upgrading 10 feeders for the Apollo Bay harbour development at a cost of $4.9 million. It noted that feeders CLC006 and CLC007 currently have utilisation rates of 101 per cent and 89 per cent respectively.[114]

Our analysis shows that WBL4 currently faces maximum demand above its operational capacity. In addition, Powercor's demand growth from WBL4 and CLC006/7 are consistent with or lower than AEMO's connection point forecast growth of 1.2 per cent per annum (summer peaking) over ten years.[115] On the information before us we consider augmentation of feeders around the Terang area may be required.

Deer Park

Powercor has proposed $13.4 million for the following new feeders in the Deer Park area:

- Eight new feeders from the new Truganina Zone Substation. The first five feeders will be completed over the period 2014–18 at a cost of $1.6 million (which includes $0.2 million incurred in 2014 and 2015). An additional five feeders are scheduled for completion for 2019 and 2020 at a cost of $7.2 million.[116]
- a further two feeders, which Powercor did not provide information to justify:
    - Establishing a new SU14 feeder to a customer site, $2.0 million to be completed in 2019.
    - MLN32 New 22kV Feeder to offload MLN24 & accept 5MW from BMH, $1.8 million by 2017.

We consider the additional five feeders from Truganina proposed for 2019 and 2020 could be deferred until the following regulatory control period, consistent with our view that the third transformer at Truganina Zone substation can be deferred.

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113 Based on our analysis of Powercor's augmentation capex model submitted as part of its regulatory proposal.

114 Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015, p. 6.

115 AEMO, *Transmission Connection Point Forecasting Report for Victoria,* September 2014.

116 We note Powercor's augex modelling includes forecast expenditure for the installation for 10 feeders, however Powercor report they will install eight. See Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015, p. 7.

In the absence of information on customer contributions, we consider it is probable based on our demand forecast that the feeder to the customer site can be delayed to the following regulatory control period.

Ballarat

Powercor has proposed a large increase (from $2.1 million to $13.2 million) for projects in the Ballarat area. It explains that the increase is due to deferred projects that were planned for the 2011–15 period.[117]

Powercor proposed two new feeder projects from the Ballarat South zone substation:

- BAS31 New 22kV Ring Road feeder. This new feeder is to the western Ballarat area to supply residential load growth in the new Lucas suburb and commercial/industrial load growth in the Ballarat West Employment Zone. This is not scheduled until 2020.
- BAS33 New 22kV Sebastopol feeder. This is a new feeder to supply new load and development, scheduled for completion by 2017.

We consider it is likely that the need for the BAS31 can be efficiently deferred to the next regulatory control period. This is based on Powercor's forecast of 0.5 - 2 per cent growth rates on its feeders across Ballarat, which is higher than AEMO's Ballarat connection point growth forecast of 0.4 per cent per annum (winter peaking).[118]

We also note that it is unclear how customer contributions for these developments have been considered in the expenditure forecasts.

Bendigo

Powercor proposed $10.2 million for new feeder projects to increase capacity in the Bendigo area over the next five years. It stated that development in the inner urban suburbs is near capacity and now moving to the outer urban areas.[119] Three projects make up 60 per cent of the planned HV feeder forecast expenditure in the Bendigo area (to Huntly, Heathcote and Ravenswood):

- Powercor proposed $3.9 million to increase feeder capacity for Huntly, which includes the construction of a new feeder (EHK11) in 2019 and expansion of the EHK22 feeder in two stages in 2018 and 2020.[120]
- Powercor proposed $1.2 million to increase feeder capacity for Heathcote, which includes an extension of the BGO23 feeder and an unnamed new subsidiary feeder, projects planned for 2019 and 2017 respectively.

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[117] Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015, p. 7.

[118] AEMO, *Transmission Connection Point Forecasting Report — For Victoria*, September 2014.

[119] Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015..

[120] Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015, p. 8.

- Powercor proposed $1.0 million for a feeder tie between feeders CMN3 and BET4 for Ravenswood. This project is scheduled for 2019.

We recognise that some feeders in the area currently operate above their maximum operational capacity. However, we note that its demand growth forecasts across Bendigo feeders (EHK, BGO, CMN, BET) vary between 0.4 - 3 per cent per annum. Most of these feeder growth forecasts are higher than AEMO's connection point growth forecast from Bendigo (66kv) of 0.5 per cent per annum over 10 years.[121] Further, some feeders that Powercor has proposed to augment e.g. EHK23, BGO23, will not be close to operating at capacity even assuming Powercor's demand growth forecast.

This evidence indicates that Powercor may need to undertake some augmentation of feeders around Bendigo, but it doesn't justify additional expenditure beyond its actual expenditure over the 2011–15 period, consistent with our position across all HV feeders. We therefore consider an allowance based on historical expenditure is appropriate.

Keilor

Powercor proposed $4.8 million to continue augmentation work in the Keilor area, as this high growth area of Western Melbourne reaches maturity.[122] It noted that the forecast expenditure is a reduction from the $9.9 million expenditure in the 2011–15 period.

Powercor did not provide sufficient information to justify feeder augmentation works in the Keilor area. Our analysis also shows that most of the proposed expenditure is for the Woodend area, however it appears that even assuming Powercor's expected demand growth rate (1.5 - 2 per cent per annum) none of the feeders will be operating above their maximum capacity in 2020.

Other areas (Horsham, Kerang, Shepparton, Altona-Brooklyn, Red Cliff)

Powercor stated that proposed HV feeder expenditure in these areas have similar or comparable expenditures between the 2011–15 and 2016–20 regulatory control periods, and have therefore been excluded from a detailed expenditure analysis.[123]

Our analysis of the proposals in these areas revealed there are inconsistencies between Powercor's demand forecast and AEMO's connection point forecast by area.[124] We also found that on current and forecast utilisation rates, some feeders may require augmentation:

- Horsham – Powercor forecast growth rates between 0.3 and 2.5 per cent across these feeders, which is on average higher than AEMO's forecast winter maximum

[121] AEMO, *Transmission Connection Point Forecasting Report — For Victoria*, September 2014.

[122] Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015, p. 9.

[123] Powercor, *Response to AER Information Request Powercor IR# 017*, 30 July 2015, p. 9.

[124] AEMO, *Transmission Connection Point Forecasting Report — For Victoria*, September 2014.

demand growth of 0.6 per cent per annum. Additionally, based on Powercor's forecast, only one feeder is expected to be around capacity in 2020.

- Kerang – Powercor forecast growth rates between 0.2 and 1.2 per cent across feeders from Swan Hill and Cohuna. This growth rate is higher than AEMO's summer maximum demand growth forecast from the Kerang connection point of 0.1 per cent per annum (summer peaking). As most of the augmentation is proposed for 2019 and 2020, we consider there is scope for these projects to be delayed.
- Shepparton – Most of Powercor's proposed feeder augmentation in this area is around Mooroopna, which appears to have some feeders running at high utilisation rates at present. Although Powercor's demand forecast (0.5 - 1 per cent) is higher than AEMO's (0.4 per cent summer peaking), it does appear that some augmentation may be warranted.
- Altona-Brooklyn – A number of Powercor's feeders around Laverton and Laverton North are operating near capacity and we recognise demand is increasing in these areas.
- Red Cliff – Powercor's demand growth forecasts on feeders around Merebin and Mildura vary considerably (0 to 4.8 per cent), which appears to be consistent with AEMO's forecast (2.9 per cent per annum, summer peaking). However it appears that none of the feeders in Merebin will be at capacity in 2020 based on Powercor's growth rates.

This evidence indicates that Powercor may need to augment feeders in some of these areas, but it doesn't justify additional expenditure beyond its actual expenditure over the 2011–15 period, consistent with our position across all HV feeders. We therefore consider an allowance based on historical expenditure is appropriate.

Feeder ties

Additionally, we also note there are 22 feeder ties itemised in the plan, which amounts to $8.3 million in total. Feeder ties connect a subsection of a network to an adjacent or parallel part of the network, which allows for the quick restoration of supply in the event of an outage. We therefore consider that feeder ties are primarily used to improve reliability rather than for augmentation purposes. Powercor did not provide information to justify this expenditure. This adds further support to our conclusion of an overestimate in the forecast.

Voltage regulators

Powercor has proposed $6.2 million for 23 new or upgraded voltage regulators to address expected demand-driven voltage issues.[125] However, Powercor has not provided supporting information to justify expenditure on voltage regulators. We note

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[125] Powercor, PAL CONFIDENTIAL MOD 1.17 - PAL augmentation capex.

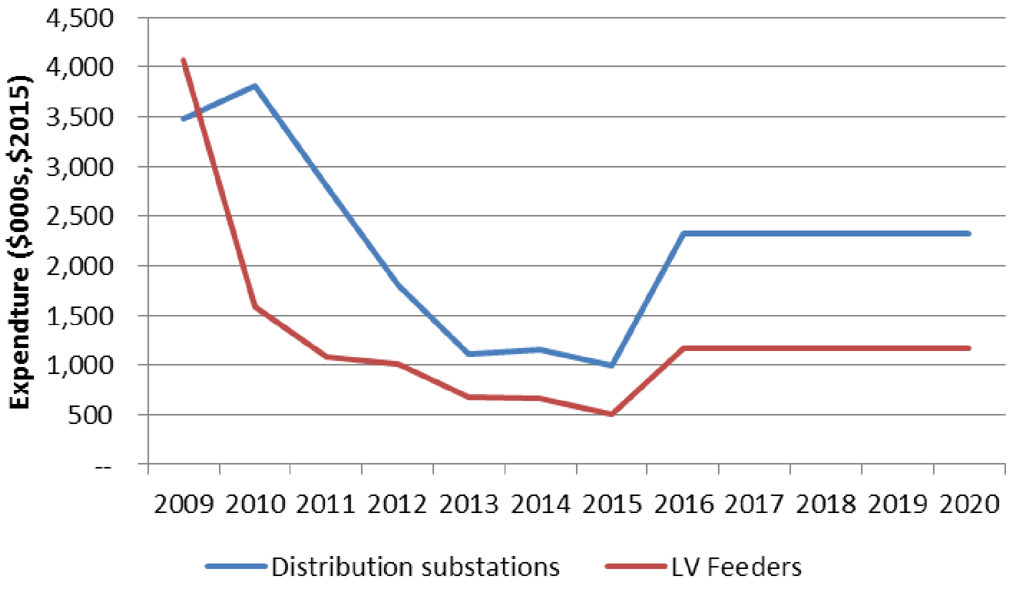
that eight regulators, totalling $2.2 million is forecast for the last year of the regulatory control period. In the absence of further information, we consider it is probable based on our demand forecast that the expenditure for the final eight voltage regulators can be delayed to the following regulatory control period.

LV feeders and distribution substations

Powercor forecast $6.2 million ($2015) for augmentation of LV feeders and distribution substations. This represents approximately a 54 per cent increase from actual expenditure of $4 million in the 2011–15 period. Powercor stated the forecast for LV Feeders and distribution substations was based on the historical average expenditure from 2009–15.[126]

Figure 6.9 shows that Powercor's expenditure on LV feeders and distribution substations steadily decreased between 2009 and 2015, but is forecast to increase in the 2016–20 period. Given the observed trends in expenditure over the last regulatory control period, an averaging process that picks up two high years from the regulatory control period before last (2009 and 2010) may tend to bias the forecast upward.

Figure 6.9 Powercor's historic and forecast expenditure on LV feeders and distribution substations ($2015)



Source: AER Analysis, Powercor's reset RIN.

Powercor did not provide information to justify why a forecast based on its 2009–15 average expenditure is appropriate, nor why it forecasts an increase in expenditure on LV feeders and distribution substations.

126 Powercor response to AER Powercor 017, p. 10.

Although Powercor did not discuss growth in network demand as a driver of this increased expenditure, we do not accept that demand is increasing significantly overall. As we outline in Appendix C, we consider that the available evidence points to flatter demand growth for the 2016–20 period. This suggests that Powercor's demand-augex for LV feeders and distribution substations may be overstated when compared to a more realistic expectation of demand over the 2016–20 period.

We consider it is appropriate to consistently base trend forecasts around the same years from one regulatory control period, where the data does not indicate a departure from current expenditure levels. Our alternative estimate is therefore the average of 2011–14, resulting in a forecast of $4.4 million. We consider this estimate reflects the prudent and efficient amount for Powercor to meet expected demand growth in localised areas of its network.

Voltage compliance program

Powercor proposed $27.3 million to install 89 bidirectional voltage regulators on its network to manage voltage levels on long feeders driven by the uptake of solar PV generation. It proposed this expenditure as non-network capex,[127] however we have considered it as non-demand augex.

We consider expenditure on bidirectional voltage regulators is not justified. Below we highlight key concerns with the proposal, in particular in reference to findings from the AECOM solar impact study.

Powercor stated that it will selectively target long rural feeders to upgrade voltage regulation devices. It says this is required to ensure voltage levels remain within limits and enable customers to connect solar PV cells to the network, and in turn to maintain compliance with the Victorian Electricity Distribution Code (EDC).[128]

Powercor referenced a report by AECOM. The report suggested, however that there is no need for voltage regulators at present, as Powercor is within its prescribed regulatory requirements.[129] Further, it noted that Powercor reviewed its existing policies and introduced a customer guideline for connecting to the HV network.[130] AECOM considered that the guideline should assist in maintaining HV distribution system quality of supply.

The AECOM report concluded that there are no voltage control issues at present, based on analysing voltage profiles across the nine feeders selected by Powercor for analysis. Further, PV penetration would need to reach 20 per cent for reverse feeder power flow. The maximum current PV penetration on any of the rural long feeders in

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[127] Powercor , *Regulatory Proposal 2016–20*, Appendix E, April 2015, p. 174.

[128] Powercor, *Regulatory Proposal 2016–20, Appendix E.67*, April 2015, p. 1.

[129] Powercor, *Regulatory Proposal 2016–20, Attachment 9.24*, April 2015, p. i.

[130] Powercor, *Customer Guideline – High voltage distribution connected embedded generation, Version 2*.

the study was 16 per cent. AECOM therefore found that none of the feeders studied recorded step voltages outside of the required range in the EDC.[131]

The report projected a need for installation of new regulators (including replacing unidirectional with bidirectional) when certain threshold levels of PV uptake are reached. This projected need is based on an assumption of continuing growth in PV installation leading to voltage standard breaches. However, the report tempered the requirement with the following statement (noting that Powercor has Advanced Metering Infrastructure (AMI), which enables detailed analysis of voltage issues across its entire network in near real-time):[132]

> To provide more accurate network modelling and to assess the impacts on the system voltages during the different loading periods, metered data at solar cell connection points should be obtained on the selected distribution feeders to perform additional studies.

We consider that the recommendation to engage in additional studies is an indication that the need for bidirectional regulators is not immediate. Additionally, once Powercor studies the additional data provided by AMI meters, it can provide a more prudent and robust as well as more targeted proposal for bidirectional voltage regulators.

Powercor also assumed that there will be 13.3 per cent growth in PV installation across every feeder in its network (evident in the extract from the AECOM report),[133] although there is no substantive reason given to such a uniform increase across all feeders. Powercor did provide the following information:[134]

> At Powercor 235 MW of solar PV is installed (as at March 2015) which is 37% of solar PV installed within Victoria.
>
> At Powercor the 12 month up take of solar PV to Sept 2014 has been 12,514 Customers with a generation of 51.4MW. Given Queensland and SA take up rates, the decreasing costs of solar PV systems and ability for customers to offset energy costs, this increase in solar PV is projected to continue at this present rate. Based on this current rate of up-take, by 2020 Powercor's customer will have deployed in total approximately 570MW.

Without substantive reasoning and evidence to support a PV uptake rate similar to Queensland's and South Australia's, it is unclear to us whether or not a uniform rate over time and across the network is reasonable.

We consider that based on information from the AECOM study, investment in bidirectional voltage regulators is not required over the 2016–20 period for Powercor to manage voltage levels on its network. We note that all feeders are currently within

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131 Powercor, *Regulatory Proposal 2016–20, Attachment 9.24*, April 2015, p. 75.

132 Powercor, *Regulatory Proposal 2016–20, Attachment 9.24*, April 2015, p. i.

133 Powercor, *Regulatory Proposal 2016–20, Attachment 9.24*, April 2015, pp. a-1–a-9.

134 Powercor, *Regulatory Proposal 2016–20, Appendix E.67*, April 2015, p. 2.

regulatory requirements, and AMI meters are recommended to be used to assess voltage impacts, which suggest bidirectional regulators are not a necessity at present.

B.3 Forecast customer connections capex, including capital contributions

Connections capex is incurred by Powercor to connect new customers to its network and where necessary augment the shared network to ensure there is sufficient capacity to meet the new customer demand.

New connection works can be undertaken by Powercor or a third party. The new customer provides a contribution towards the cost of the new connection assets. This contribution can be monetary or in contributed assets. In calculating the customer contribution, Powercor is required to take into account the forecast revenue anticipated from the new connection. These contributions are subtracted from total gross capex and as such decrease the revenue that is recoverable from all consumers. Customer contributions are sometimes referred to as capital contributions or capcons.

The mix between net capex and capcons is important as it determines from whom and when Powercor recovers revenue associated with the capex investment. For works involving a customer contribution, Powercor recovers revenue directly from the customer who initiates the work at the time the work is undertaken. This is different from net capex where Powercor recovers revenue for this expenditure through both the return on capital and return of capital building blocks that form part of the calculation of Powercor's annual revenue requirement.[135] That is, Powercor recovers net capex investment across the life of the asset through revenue received for the provision of standard control services. Powercor has forecast $458.1 million ($2015-16) of expenditure for connection works for the 2016–20 regulatory control period, net of customer contributions. Table 6.10 shows Powercor's proposed allowance for connections expenditure. This is made up of a forecast of gross expenditure of $774.1 million and customer contributions of $316.0 million.

Table 6.10 Powercor proposed connections capex ($2015/16, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Gross connections capex	166.1	170.8	147.5	143.7	146	774.1
Customer contributions	69.5	76.2	59.3	55.6	55.4	316.0
Net connections capex	96.7	94.5	88.2	88.1	90.5	458.1

Source: Powercor, PAL PUBLIC MOD 1.18 - PAL Capex consolidation.xlsx.

135 For more information on the building blocks included in the determination of Powercor's annual revenue requirement see our attachments on the regulatory asset base and regulatory depreciation.

B.3.1 AER Position

We do not accept Powercor's net connections capex forecast. We have instead included an amount of $365.8 million ($2015−16) in our substitute estimate of forecast capex. Our decision is based on gross connections expenditure of $724.7 million and customer contributions of $358.9 million ($2015−16).

To reach our alternative estimate of Powercor's connections forecast, we considered:

- the trends in Powercor's connections capex across time, and
- Powercor's forecast methodology and the data relied on to produce the forecast.

Our alternative estimate is shown in Table 6.11.

Table 6.11 AER adjusted connections capex ($2015/16, million, excluding overheads)

Category	2016	2017	2018	2019	2020	Total
Gross connections capex	151.2	158.1	139.4	137.0	138.9	724.7
Customer contributions	75.2	78.4	69.4	67.9	67.9	358.9
Net connections capex	76.0	79.6	70.0	69.1	71.0	365.8

Source: AER analysis.

We note that stakeholders have raised some concerns with the classification of connection services.[136] Our assessment of service classification is discussed in Attachment 13.

B.3.2 Trend analysis

As we noted above in section A.2, when assessing Powercor's connections capex we have considered the trends in actual and forecast capex.[137] We have used this analysis to provide context to Powercor's proposal, in particular trend analysis has allowed us to:

- gauge the degree to which Powercor's proposal is consistent with past connections capex
- understand variations between Powercor's capex allowances for connections and that incurred in the 2011–15 regulatory control period, and
- the basis of the key drivers underlying Powercor's forecast methodology connections capex for the 2016–20 regulatory control period.

136 Consumer Challenge Panel 3 – Victorian DNSPs revenue reset comments on DNSPs proposal pp. 54-56. Vector, *Submission on the AER's Issues Paper on Victorian Electricity Distribution Pricing Review for 2016–2020,*13 July 2015 pp. 4-5.

137 This is one of the capex factors to which we are required to have regard to under the NER. (NER, cl. 6.5.7(a)(5)).

As explained in the next section, we have also used trend analysis as a basis for our substitute estimate where our analysis has shown that the forecast methodology used by Powercor may lead to an overestimate of the required expenditure.

B.3.3 Basis of AER’s alternative estimate

When determining our alternative estimate of net connections capex and customer contributions we must be satisfied of Powercor's requirements for the 2016–20 regulatory control period. We have:

- adopted Powercor’s forecast for connection types we consider reasonable, and
- where we are not satisfied with Powercor’s approach we have substituted the historical trend in expenditure.

In determining our substitute estimate of net connections capex and customer contributions, we compared Powercor's proposal to our substitute estimate that we constructed using the approach and techniques outlined in the following sections. Where our substitute estimate trends forward historical expenditure, this provides Powercor an allowance for net connections capex and customer contributions for the 2016–20 regulatory control period that reflects the actual expenditure from the 2011–15 regulatory control period. With respect to the forecasts of low volume connections, we are satisfied that Powercor’s forecast approach provides a realistic expectation of the connections capex it requires for the 2016–20 regulatory control period.

Whilst we note that there are pockets of growth in Powercor’s network, as discussed in Appendix C, peak demand growth across the whole of Powercor’s network is likely to be relatively flat. We note that an input into forecasting maximum demand is the level of customer growth on the network. We consider that forecast stability in peak demand indicates that observed trends in network growth capex (including connections) are reasonable indicators of future capex requirements. We are satisfied that it is reasonable to rely on recently observed trends as a basis for establishing a substitute estimate.

We further note that Powercor has relied on trending the low volume connection projects for which there are no known projects. We are satisfied that this approach is reasonable and consider it valid for all categories where volumes and unit costs are likely to be relatively constant.

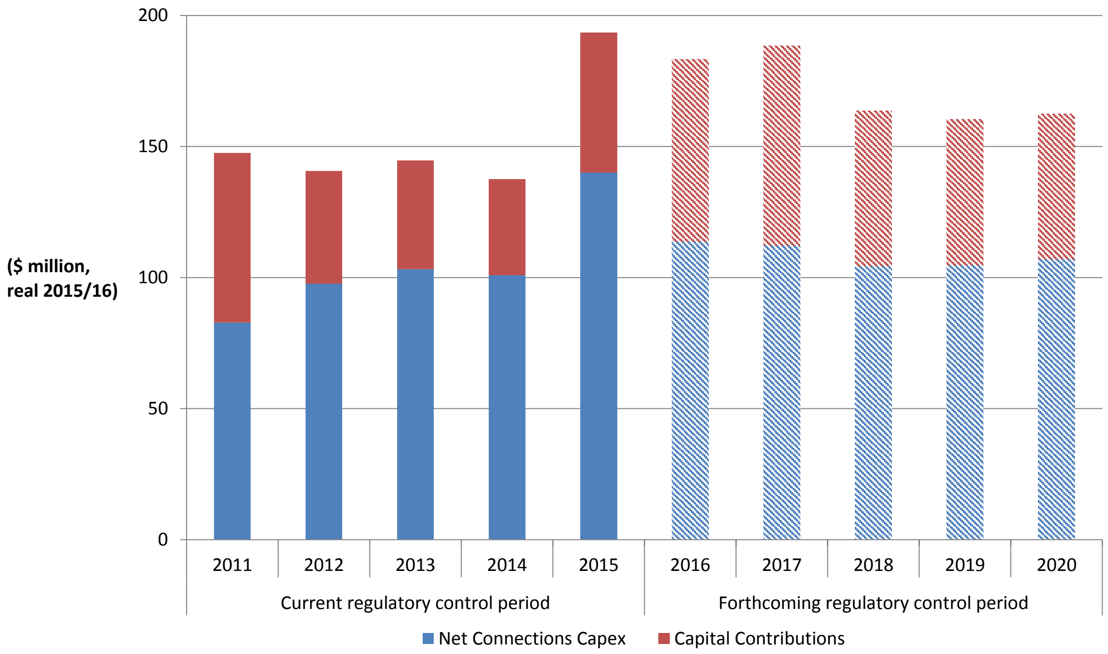
We recognise that our alternative estimate cannot perfectly predict Powercor’s connections capex for the 2016–20 regulatory control period, in the same way that no prediction of future needs will be absolutely precise. However, we consider our approach is based on verifiable data. Further, we are satisfied historical capex is an appropriate basis on which to determine forecast connections capex because the drivers of customer connections remain relatively constant across regulatory control periods. In addition, there are no external or exogenous factors that have been identified that would result in expenditures that were inconsistent with recently observed trends.

B.3.4 AER Analysis

Actual and forecast customer connections

Figure 6.10 shows the trend in Powercor's actual and forecast gross connections capex by both net connections capex and customer contributions.

Figure 6.10 Powercor connections and capital contributions, historic actual and proposed for forecast 2016–20 regulatory control period ($2015/16, million)



Source: AER analysis, PAL PUBLIC MOD 1.18 - PAL Capex consolidation.

Figure 6.10 shows that between 2011 and 2014 gross connections capex was relatively stable. With respect to gross capex, there has been a relatively small decline in capital contributions, resulting in increases in the prominence of net capex.

We note there is a timing mismatch whereby Powercor submits its regulatory proposal before the calendar year 2015 is complete.[138] This means the expenditure and volumes that Powercor has reported for 2015 are estimates. Given this, we have not used the 2015 data for the purposes of comparing actual expenditure observed in the last regulatory control period with the expenditure forecast by Powercor for the next period.

Excluding the estimated year, Powercor's proposal represents an average increase of 28.3 per cent from actual expenditure from the current period in net terms.

[138] Powercor submitted its regulatory proposal to the AER on 30 April 2015, in advance of the actuals for calendar year 2015 being finalised.

At the time of the last determination, we note our consultant found that during the 2006-10 regulatory control period the Victorian DNSPs:[139]

- consistently forecast higher levels of expenditure than has been required, and
- projected higher levels of expenditure for the estimate years of the regulatory control period than has actually been incurred.

Historic spend

In determining whether we are satisfied that Powercor's forecast connections capex meets the criteria in the rules we must have regard to Powercor's actual and expected capex during any preceding regulatory control periods.[140] We note that Powercor is forecasting to underspend its regulatory allowance in the 2011–15 regulatory control period by 14 per cent.[141] Powercor considers the primary reason for underspending to be a result of the slowdown in the broader economy following the global financial crisis.[142]

Figure 6.11 compares Powercor's connections capex spend in the 2011–15 regulatory control period with the allowance included in the capex determination.[143]

[139] Nuttall Consulting Report, *Capital Expenditure, Victorian Electricity Distribution Revenue Review - A report to the AER, Final Report*, 4 June 2010, P. 23.

[140] NER 6.5.7(e)(5).

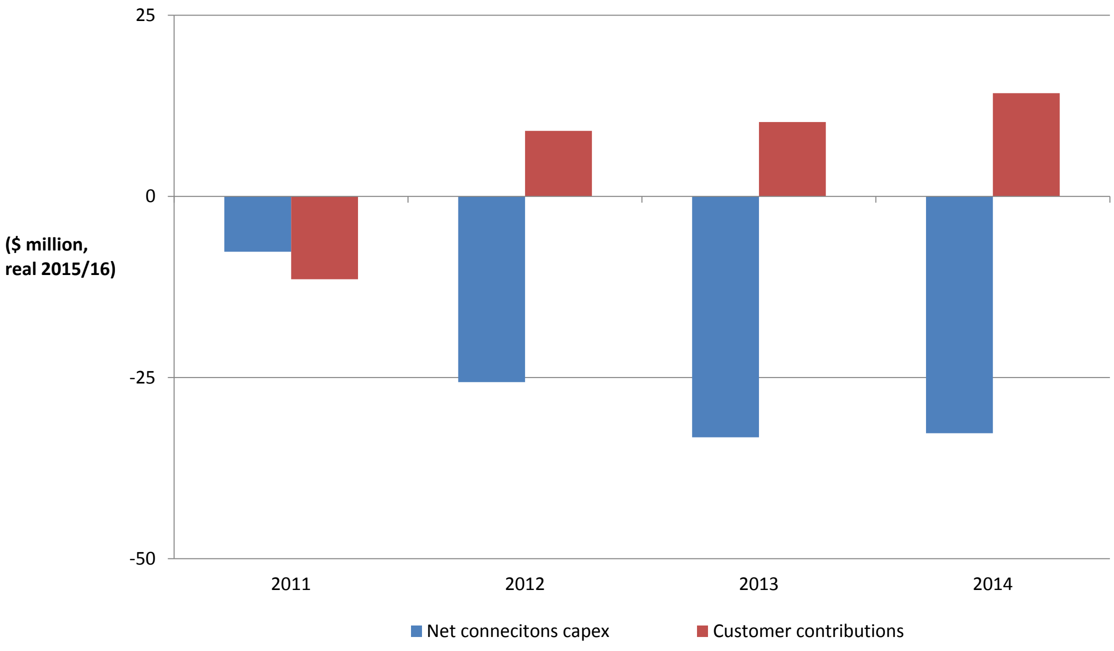
[141] Powercor, *2016–20 Price Reset Appendix E Capital Expenditure April 2015*, p. 116.

[142] Powercor, *2016–20 Price Reset Appendix E Capital Expenditure April 2015*, p. 116.

[143] 2011-15 allowance: AER Victorian Distribution Determinations 2011-15 - Final Decisions - Table 8.24 (adjusted for inflation)

2011-15 actual: Powercor Reset RIN – Table 2.1.1 Expenditure Summary – Standard Control Capex – Connections.

Figure 6.11 Powercor 2011-14 difference between actual and allowed connections capex ($2015/16, million)



Source: AER analysis.

We consider that across time changes to definitions of expenditure, service classifications or cost allocation methods can impact on the availability of comparable data. On this basis, we sought feedback from Powercor on whether changes to service classifications or cost allocation methods may explain the differences illustrated in Figure 6.11.[144] Powercor stated that the differences between the 2011–15 forecast and actual connections capex was a consequence of their previous forecasting methodology overestimating the volume of connections.[145] Powercor considers that changes in the classifications of services did not have an impact.[146]

We are satisfied that Figure 6.10 shows that compared with its allowance in the 2011–15 period, Powercor underspent on net connections capex and received more customer contributions than forecast. We note that a major feature of the regulatory framework is the incentives Powercor has to achieve efficiency gains whereby actual expenditure is lower than the allowance. Differences between actual and allowed connections capex could be the result of efficiency gains, forecasting errors or some combination of the two. Powercor noted it has improved its forecasting methodology for the 2016–20 regulatory control period by incorporating economic modelling and utilising key economic and demographic variables.[147] On this basis Powercor considers

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[144] Powercor, *Response to AER Information Request IR# 012*, 24 July 2015.

[145] Powercor, *Response to AER Information Request IR# 012*, 24 July 2015.

[146] Powercor, *Response to AER Information Request IR# 012*, 24 July 2015.

[147] Powercor, *Response to AER Information Request IR# 012, 24 July 2015*.

it is not appropriate to compare the actual and allowed standard control connections capex.[148] We have considered Powercor's forecasting methodologies when considering if the proposed expenditure forecast is justified.[149]

B.3.5 Powercor's forecasting methodology

Powercor has combined two separate methodologies for forecasting customer connections, depending on whether the category of connection has a high or low volume of activity:

- for connection activities with high volumes, Powercor has adopted a two stage process. Powercor relied on an external consultant, the Centre for International Economics (CIE) to produce volume forecasts to which Powercor applied historical unit rates to generate a gross capex forecast [150], and
- for low volume categories of connections, Powercor has generated its forecast using a bottom-up build of major projects.[151]

These forecasts are in gross terms, that is, they include customer contributions. Powercor has derived a customer contribution rate by sampling historical projects that it applied to the gross forecasts to produce forecasts of net connections capex and customer contributions.[152] Table 6.12 shows Powercor's forecasts for connections capex.

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148 Powercor, Response to AER Information Request IR# 012, 24 July 2015.

149 NER cl. 6.5.7.

150 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, p. 112 Table 5.1. High volume categories of connection follow the RIN definitions of residential complex at LV; residential complex HV works connected at LV, commercial/industrial HV works connected at LV; and subdivision.

151 Low volume categories of connection follow the RIN definitions of commercial/industrial connected at HV, embedded generation and recoverable works (reported as quoted services). In determining its forecasts for these low volume categories, Powercor used forecasts of customer connections estimated using a bottom-up build of major projects.

152 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure,* April 2015, p. 110.

Table 6.12 Powercor proposed connections capex ($2015/16, million, excluding overheads)

	2016	2017	2018	2019	2020	Total
High volume categories forecasts						
Gross connections capex	86.3	84.1	79.5	78.0	78.4	406.3
Customer contributions	30.7	34.3	26.3	24.1	24.0	139.4
Net connections capex	55.5	49.7	53.1	53.9	54.4	266.6
Low volume categories forecast						
Gross connections capex	26.9	31.3	11.4	7.4	7.4	84.4
Customer contributions	9.6	12.8	3.8	2.3	2.3	30.8
Net connections capex	17.3	18.5	7.6	5.1	5.1	53.6

Source: Powercor, PAL PUBLIC MOD 1.18 - PAL Capex consolidation.
Note: Excludes recoverable works, gifted assets and escalators.

In determining whether we are satisfied that Powercor's forecast meets the capex criteria, we have assessed the above forecasting methodologies.

High volume categories of connections

Powercor derives its high volume forecast by multiplying volumes as calculated by the CIE by its estimate of unit costs.[153] CIE produced forecasts for residential, commercial/industrial and subdivision high volume categories.[154] It did this by:

- assessing historical correlations between each connection type and economic and demographic variables, identifying population growth, dwelling growth and economic activity as key drivers of connections expenditure on Powercor's network[155]
- isolating the sensitivity of changes in these variables on the amount of connection activity, and[156]
- applying the sensitivities to independent forecasts of the identified key drivers.[157]

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[153] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor,* November 2014. (Powercor, *Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor,* November 2014).

[154] Powercor, *Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, Chapter 6.

[155] Powercor, *Regulatory Proposal* 2016–20, *Appendix E: Capital Expenditure*, April 2015, p. 113.

[156] Powercor, *Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, Chapter 5.

[157] Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure,* April 2015, p. 113

To determine whether we are satisfied this methodology produces a forecast of capex that Powercor requires to achieve the capex objectives, we have assessed:

- the correlations of observable trends in the economic and demographic variables and Powercor's historic connections volumes
- the projections of the economic and demographic variables underlying the forecast relied on by Powercor, and
- the use of historic unit costs on each of the volume projections.

We have made these assessments for each forecast of residential, commercial/industrial and subdivision connections categories in the following sections.

Residential Connections

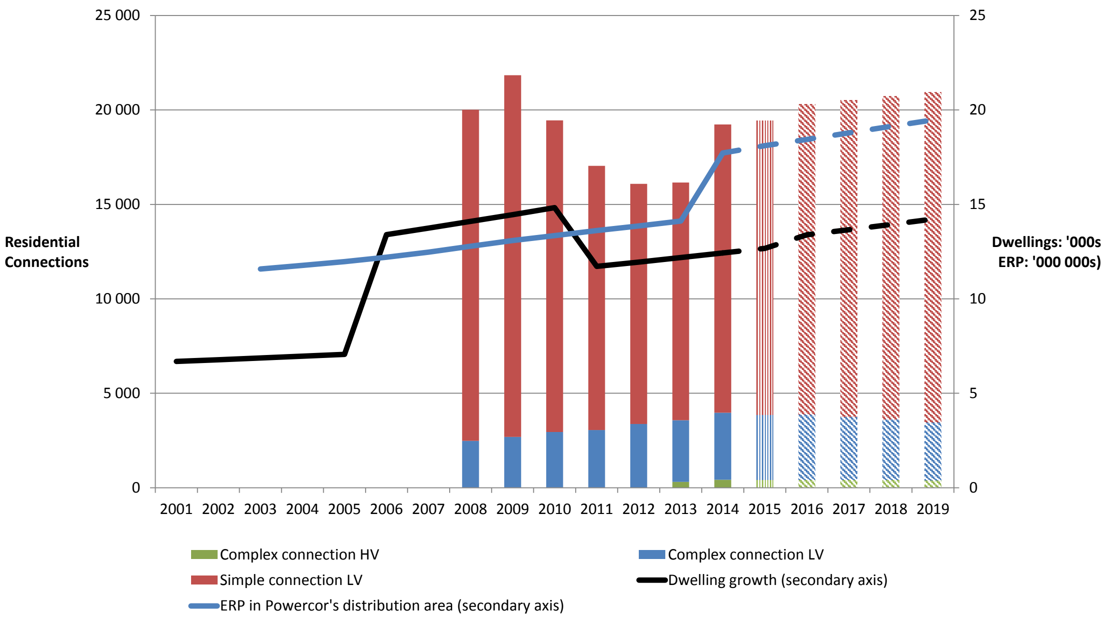
We are not satisfied that Powercor has demonstrated that the forecast volumes of residential type connections represent a realistic expectation of this type of connection activity that Powercor will be required to undertake over the 2016–20 regulatory control period. In determining this we consider that CIE has:

- not accurately identified the key drivers of residential connection activities, and
- relied on historical and forecast data that has been prepared on an inconsistent basis.

Figure 6.12 shows the historical residential customer connections on Powercor's network and the volumes forecast for the 2016–20 regulatory control period. We have also included the trends in estimated resident population (ERP) and dwelling growth as these are the variables CIE has identified as key drivers of the number of residential connections projects.[158]

[158] Powercor, *Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor,* November 2014.

Figure 6.12 Powercor residential connections identified by key drivers



Source: AER analysis.[159]

CIE is forecasting the number of residential connections for both LV and HV works to grow in line with the forecasts of dwelling approvals.[160] The historical dwelling data is published by the ABS once every five years. To produce the trend shown in Figure 6.12, Powercor interpolates this data to produce the yearly time series shown.[161]

We note Figure 6.12 shows an increasing trend in the growth of dwellings in Powercor's distribution area. Further, we note there are significant positive and negative spikes that coincide with the periodic publication of the ABS dwelling data. Given the timing of these spikes we consider the historical data CIE has relied on represents the average change in total dwellings across time rather than the actual year on year trend in total dwellings.

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159 Connection data: PAL PUBLIC RIN 1.1 Powercor, Vic Reset RIN 2016–20 - Consolidated Information, PAL PUBLIC RIN 1.19 Powercor, 2009-2013 Category Analysis RIN and PAL PUBLIC RIN 1.20 Powercor, 2014 Category Analysis RIN

Dwelling growth: PAL PUBLIC MOD 1.51 - CIE customer number forecasts February 2015 and years prior to 2006, AER application of CIE interpolation method

Population historical years ABS – 3218.0 Estimated Resident Population, Statistical Areas Level 2 (SA2), Victoria using CIE mapping of SA2 to Local Government Areas

Population forecast years - Victoria In Future 2015 (VIF 2015) – ERP – VIFSA mapped to Powercor distribution area as described in Schedule 2 of Powercor's distribution licence.

160 Powercor, *Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 33.

161 Powercor, *Attachment: PAL PUBLIC MOD 1.51 - CIE customer number forecasts February 2015 Worksheet: "C. Dwelling forecasts*".

Further, we note the time series data beyond 2011 applies the same interpolation technique to a different source than the earlier years, the 2016 projection of dwellings made by the Victorian Department of Transport, Planning and Local Infrastructure.

The projections of total dwellings form a key input into CIE's forecast of residential connections. In turn, these dwelling projections rely on historical and forecasts of the estimated resident population (ERP) within Powercor's network. Figure 6.12 shows the ERP used in the dwelling projections.[162] CIE sourced the historical ERP from ABS data mapped to Powercor's distribution area, we have used the same mapping to the ERP underlying the dwelling projections. We note that the projections incline at a similar rate to the historical ERP after an initial step change. The step change in the projection is caused by different assumptions of the birth rate, death rate and net migration within Powercor's distribution area than the ABS used to collect the actual data.[163] We are not satisfied Powercor has demonstrated that the assumptions in the forecast are more realistic than those used by the ABS.

After establishing the trend and the projections of changes in population and dwelling growth, CIE then determined the correlation of these variables to the number of residential connections.[164] CIE noted that there are difficulties associated with the limited amount of time series data available and the inherent volatility and potential inaccuracy of data at a local and regional level.[165] CIE applied statistical modelling techniques to overcome these difficulties, from which CIE determined a model fit which it considered most appropriate for forecasting residential customer connections.[166]

For each connection type, CIE compared how this model fit performed in predicting residential connections when inputting the selected driver variables.[167] In doing so CIE determined that:

- the number of private sector house approvals is the key driver of residential complex LV projects, and[168]
- the change in population is the key driver of residential complex HV projects.[169]

162 Underlying CIE's forecasts for residential connections are projections on dwelling growth in Victoria. CIE relies on projections included in the Victoria in Future 2014 Population and household projections. Figure 3 is updated for to include the data published in the Victoria in Future 2015 report which was not available at the time Powercor submitted its regulatory proposal.

163 The population projections relied on in the Victoria in Future 2015 report utilise the same Cohort Component Model used by the ABS to generate the historical data. The VIF 2015 projections has applied different assumptions to the ABS for the key drivers of population change: fertility and mortality rates.

164 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 9.

165 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 13.

166 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, pp. 14-15.

167 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 14.

168 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 15.

We note that in determining these relationships, CIE has relied on a limited series of observations comparing the predicted connections with the actual residential connections.[170] Also, CIE's model for LV connections, which uses housing approvals as its key driver, shows a weaker predictive power than the HV connection model that relies on population growth.[171] Further, we consider the actual data used to observe the relationship between the drivers and residential connections is not consistent with the projections used in the forecast.

Accordingly, we are not satisfied that Powercor's expectation that residential connections for both LV and HV works will grow in line with forecasts of dwelling approvals represents the best possible forecast in the circumstances. We have instead included in our alternative capex estimate an amount which trends forward the average of the actual residential connections to Powercor's network over the 2011-14 period. Table 6.13 compares Powercor's proposal with the actual expenditure over the 2011–15 regulatory control period for residential connections.

Table 6.13 Powercor residential connections, actual and proposed ($2015/16, million, excluding overheads)

	2011–15 expenditure	2016–20 proposal
Gross connections capex	165.4	178.5
Customer contributions	72.3	61.2
Net connections capex	93.1	117.3

Source: AER analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation.

Note: Includes estimated year 2015. Excludes recoverable works, gifted assets and escalators.

We discuss the basis of our alternative estimate in the section B.3.3.

Commercial/industrial Connections

We are not satisfied that Powercor uses a realistic expectation of the volume of commercial/industrial type connection activities that it will be required to undertake over the 2016–20 regulatory control period. In estimating the volume of commercial/industrial connection activities, Powercor have again relied on statistical modelling undertaken by CIE.

In summary:

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169 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 16.

170 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, pp. 15-17.

171 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, comparing Figure 2.13 and 2.15.

- CIE relies on econometric modelling that identifies that together the value of non-residential building approvals and GSP are statistically significant indicators of connection activity.[172] We note CIE has only used GSP in the forecasting process as independent building approvals data is unavailable
- we accept it is plausible for there to be a correlation between GSP and commercial/industrial connection activities. However, we are not satisfied the CIE model has reliably proven a quantitative link that can be used to reliably forecast commercial/industrial connection volumes, and
- CIE relies on inconsistent GSP forecasts to determine the value of the coefficient in its model and in applying this model to determine the commercial/industrial type connection forecast.

Given these shortcomings, we have trended forward past expenditure levels as we consider that this better reflects the expenditure likely to be required by Powercor to meet commercial/industrial connection activities.

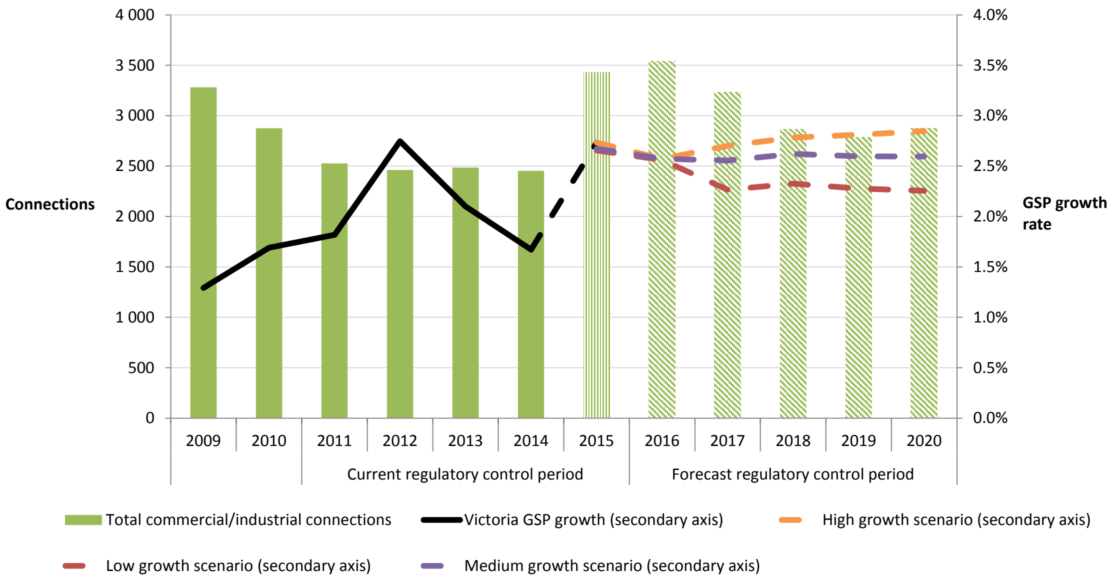
CIE econometric modelling

Figure 6.13 below shows the actual historical commercial/industrial customer gross connections capex and Powercor's forecast for the 2016–20 regulatory control period. We have also included the trend in gross state product (GSP) as Powercor relied on this as a key input into its forecasts of these types of connections projects.[173]

[172] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 23.

[173] Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure,* April 2015.

Figure 6.13 Powercor commercial/industrial customer connections - historic, actual and proposed for 2016–20 regulatory control period



Source: AER analysis.[174]

In its report CIE notes:

> The key determinant of the number of commercial/industrial electricity connections is the number of employing businesses, which is partly driven by GSP growth. A rise in the number of businesses will generally increase demand for non-residential buildings and in turn connection projects.

CIE assessed the historical correlation between connection projects and the change in population, the number of dwelling approvals, and state final demand across the electricity networks of Victoria, South Australia and Queensland. CIE determined there is a moderately positive correlation between commercial/industrial connection projects and the change in population, building approvals and economic activity.[175]

CIE has applied statistical modelling techniques to determine a model fit which it considered most appropriate for forecasting commercial/industrial customer connections. CIE tested the model by comparing its performance in predicting connections using the change in GSP and the total value of non-residential building approvals as the driver variables. CIE determined there is a statistically significant relationship between these driver variables and the number of connections. However, when CIE fits the model only with GSP it does not find a significant relationship

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[174] Expenditure data: Powercor, *Response to AER information request IR# 012*, 24 Jul 2015.
GSP – AEMO National Electricity Forecasting Report (NEFR) 2015, NEFR Supplementary Information 2015

[175] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 22.

between change in GSP and commercial /industrial connections.[176] Despite this finding, given the availability of independent forecast data, CIE has only used projections of GSP to forecast commercial/industrial connections. CIE appear to acknowledge the shortcoming in this approach and state that they have placed higher weight on historical averages than the forecast GSP growth. However, from the information provided it is not clear how this weighting process was undertaken.[177]

We note in its report CIE does not find a significant univariate relationship between change in GSP and the level of commercial/industrial connection activity.[178] With this in mind, we are not satisfied the quantitative relationship between GSP and commercial/industrial connections has been identified.

Use of different GSP forecasts

Once CIE determined the model specification for forecasting commercial/industrial connections, it used forecasts of GSP relied on by AEMO as part of its National Electricity Forecasting Report.[179] Further, CIE has relied on qualitative analysis from the Victorian Treasury of the drivers of the forecast GSP growth.[180] Given the GSP used by AEMO has a different profile to that forecast by Victorian Treasury, we consider that the drivers underlying the two forecasts are not necessarily the same. As such, we are not satisfied that the forecasts of GSP relied on to produce Powercor's forecast of commercial/industrial customer connections have been justified.

For these reasons, we are not satisfied producing a commercial/industrial connections forecasts expenditure profile that purely uses GSP forecasts is appropriate.[181] We have instead included in our alternative capex estimate an amount which trends forward the average of the actual residential connections to Powercor's network over the 2011-14 period.

Table 6.14 compares Powercor's proposal with the actual expenditure over the 2011–15 regulatory control period for commercial/industrial connections.

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176 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 25.

177 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 29.

178 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 25.

179 AEMO, *National Electricity Forecasting Report Supplementary Information 2015* - AEMO commissioned KPMG to develop forecasts of Gross State Product.

180 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 30.

181 Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 35.

Table 6.14 Powercor commercial/industrial connections - actual and proposed ($2015/16, million, excluding overheads)

	2011–15 expenditure	2016–20 proposal
Gross connections capex	151.2	168.8
Customer contributions	65.2	58.2
Net connections capex	86	110.6

Source: AER analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation.xlsx. Note: Includes estimated year 2015. Excludes recoverable works, gifted assets and escalators.

We discuss the basis of our alternative estimate in the section B.3.3.

Subdivision Connections

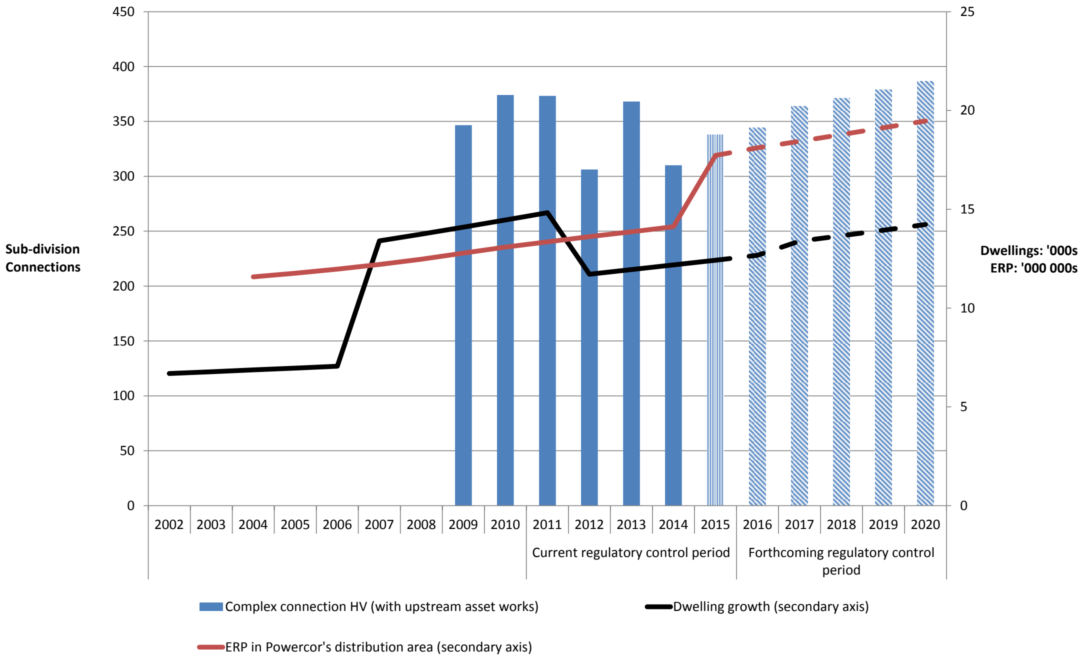
To develop a subdivision connections expenditure forecast, Powercor has again relied on a forecast of subdivision customer connections prepared by CIE. As with the residential and commercial/industrial connection forecasts, we are not satisfied that Powercor has demonstrated that this represents a realistic expectation of the volume of subdivision type connection activities that Powercor will be required to undertake over the 2016–20 regulatory control period. In determining this we consider that:

- CIE has not accurately identified the key drivers of subdivision connection activities, and
- CIE has relied on historical and forecast data that was prepared on an inconsistent basis.

Figure 6.14 shows the actual historical subdivision gross connections capex and Powercor's forecast for the 2016–20 regulatory control period. We have also included the trends in population and dwelling growth. These are the variables CIE has identified as key drivers of the number of subdivision connections projects.[182]

[182] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics, Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 27.

Figure 6.14 Powercor subdivision connections - historic, actual and proposed for 2016–20 regulatory control period



Source: AER analysis.[183]

CIE is forecasting subdivision connections to remain at a similar level as a proportion of residential connections to that experienced over 2009-13.[184] CIE expects the level of residential connections to grow in line with the forecasts of dwelling approvals. In effect, CIE is forecasting the trend in subdivision connections to resemble the forecast trend in residential connections. Unlike its forecasts for residential and commercial/industrial connections, CIE has not analysed the correlations between population, dwelling growth and subdivision connections.

CIE adopted similar statistical modelling techniques for its forecast of subdivision connections as it did for residential and commercial/industrial connections. From these techniques, CIE specified a different model fit to that used for residential and commercial/industrial connections.[185] CIE compared its models performance with the

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[183] Expenditure data: Powercor – response to AER information request 012.

Dwelling growth: PAL PUBLIC MOD 1.51 - CIE customer number forecasts February 2015 and years prior to 2006, AER application of CIE interpolation method.

Population historical years ABS – 3218.0 Estimated Resident Population, Statistical Areas Level 2 (SA2), Victoria derived from CIE mapping of SA2 to Local Government Areas.

Population forecast years - Victoria In Future 2015 (VIF 2015) – ERP – VIFSA mapped to Powercor distribution area as described in Schedule 2 of Powercor's distribution licence.

[184] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 36.

[185] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 27.

selected driver variables, total dwelling approvals and change in population.[186] In doing so CIE determined that the model is able to predict accurately the number of connections.[187] CIE noted:

- an increase in the value of non-residential building approvals results in a close to proportionate increase in the number of connections, and[188]
- an increase in the level of population growth results in a roughly proportionate increase in the number of connections.[189]

We agree with CIE that its model and variable specification show reasonable fit for forecasting subdivision connections when comparing data for historical connections. We note that the forecasts rely on the same independent projections of total dwellings and estimated residential population (ERP) relied upon in the residential connections forecast.[190] As per the residential connections model, we are not satisfied the historical data is consistent with the projections relied upon in the forecast. In particular, we note the dwelling data comes from different sources across time, further CIE has applied manipulations on this data to interpolate the actual trend.[191]

The ERP projections rely on different assumptions than the actual data relating to the fertility, mortality and net migration rates. We are not satisfied these data quality issues have been factored into the model specification processes, nor when selecting the independent forecasts of dwellings and estimated resident population. On this basis, we are not satisfied Powercor's subdivision connections forecasts represent the best possible in the circumstances. We have instead included in our alternative capex estimate an amount which trends forward the average of the actual subdivision connections to Powercor's network over the 2011-14 period. Table 6.15 compares Powercor's proposal with the actual expenditure over the 2011–15 regulatory control period for subdivision connections.

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[186] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 14.

[187] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 28.

[188] PAL PUBLIC ATT 9.3 - The Centre for International Economics, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 15.

[189] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, p. 28.

[190] Powercor, *Regulatory Proposal 2016–20, Attachment: PAL PUBLIC ATT 9.3 - The Centre for International Economics*, *Forecasting connection projects for CitiPower and Powercor*, November 2014, pp. 42–43.

[191] See our discussion of the residential connection forecasts.

Table 6.15 Powercor subdivision connections - actual and proposed ($2015/16, million, excluding overheads)

	2011–15 expenditure	2016–20 proposal
Gross connections capex	54.2	59.0
Customer contributions	24.4	20.2
Net connections capex	29.8	38.8

Source: AER Analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation.

Note: Includes estimated year 2015. Excludes recoverable works, gifted assets and escalators.

We discuss the basis of our alternative estimate below.

Unit Costs

Powercor mapped the volume forecasts generated by CIE for residential, commercial/industrial and subdivision categories to its internal reporting codes and multiplied these by applicable unit rates.[192]

Powercor derived each unit rate by dividing the relevant total expenditure and volumes for over the 2011-14 period.[193] Powercor notes that this approach reflects historical costs for similar projects and reflects the risks and uncertainties that will be present in the forecast volumes.[194]

We have assessed the Powercor mapping of the residential, commercial/industrial and subdivision categories and the descriptions of the internal function codes. Overall we consider that the mapping represents a reasonable allocation between the residential, commercial/industrial and subdivision connection categories and Powercor's internal function codes. For example:

- more than half of the residential connections of less than 63kVA are mapped as HV connections—consistent with a rural distributor such as Powercor
- subdivision costs were allocated to complex HV connections, highlighting that basic subdivision works are performed by third parties*, and*
- all co-generation function codes were allocated to complex connections, as small connection charges are either fee based or no longer provided due to a change in obligations.[195]

[192] Powercor, *Regulatory Proposal 2016–20, Appendix: E Capital Expenditure,* April 2015, p. 113.
[193] Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure,* April 2015, p. 113.
[194] Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure,* April 2015, p. 113.
[195] Powercor, *Regulatory Proposal 2016–20,* April 2015, p. 300.

Low volume categories of connections

Separate to the high volume forecasts, Powercor has undertaken forecasts of categories of connections where there are typically low volumes.[196] As explained in this section, we are satisfied that Powercor's low volume forecast reasonably reflects the required expenditure.

Powercor considers low volume connection activities are often determined by government policy or specific customer needs and have therefore adopted a combination of bottom-up builds and trending forward historical expenditure.[197] In particular for projects:

- that cost less than $2.5 million, Powercor has adopted a forecast approach that involves trending forward the 2011-14 actual historical expenditure. Powercor considers the volumes of these smaller projects to be consistent across time, and[198]
- costing $2.5 million or more, Powercor has identified known projects to occur over the forecast period. Based upon correspondence with the customer, Powercor considers these projects are highly likely to proceed and have included the connection expenditure in the forecast.[199] For connection categories where there is currently no known major project for the forecast period, Powercor has assumed expenditure based on the average major project expenditure in that category for the 2011-2014 period.[200]

For forecasts where Powercor has trended forward historical connection expenditure, we are satisfied these forecasts reasonably reflect the capex criteria. [201] We agree with Powercor that these projects have reasonably consistent volumes across time and we have included this expenditure in our determination for the 2016–20 regulatory control period. This is the same methodology as we have adopted for the development of our substitute forecast of high volume connection expenditure.

With respect to Powercor's forecasts of known major projects, we consider it is good industry practice when forecasting customer initiated work to account for the probability of delays or cancellations in projects. For example, with respect to the embedded generation projects, we note changes to the renewable energy target can impact on the demand for renewable projects. Any increase in renewable funding will act to increase the likelihood of the projects proceeding as described, while adverse changes will see the projects delayed or possibly cancelled.

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196 The low volume forecasts have been prepared for commercial/industrial connections connected at HV, embedded generation and recoverable works (reported as quoted services).

197 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, p. 114.

198 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, p. 114.

199 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, p. 114.

200 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, p. 114..

201 Powercor included business cases for each known project.

We note as part its proposal for the 2011–15 regulatory control period, Powercor's forecast identified economic conditions and development demographics, including major projects arising from mining, pipelines, generation and agricultural development as the key drivers of its major connections forecast. We have identified the following projects which were included in Powercor's allowance for the 2011–15 regulatory control period which did not proceed as forecast:

- Armstrong Creek was expected to commence in 2011, but has only just commenced[202]
- Construction of a new zone substation in Torquay and two sub-transmission lines to serve Torquay from the Waurn Ponds zone substation, was a project that was "efficiently" deferred from the current regulatory control period[203]
- Delay of the Bendigo terminal station to Charlton 66 kV sub-transmission line upgrade as a result of a third party dispute relating to property rights[204]
- Numurkah to Cobram East 66kV line upgrade project was "prudently" deferred while Powercor assessed options associated with a major supply upgrade proposal from a large customer in the area, and[205]
- A range of other smaller projects were also deferred as a result of lower than expected growth in peak demand, such as feeder projects, including Ballarat South 31 and 33, and Ford North Shore 31 and 33 22kV feeders.

When drivers change, as identified above, projects associated with the original drivers can be deferred or delayed. Given the timeframes for major projects to be completed, the changing of drivers results in a asymmetric bias for lower than expected expenditures.

We requested Powercor provide further detail for its major projects, in particular we sought that it identify how the forecast recognises the probability of project deferrals.[206] Powercor referenced customer correspondence which it considered provided the necessary surety of each projects completion.[207] We consider that such correspondence does not necessarily guarantee the project will be undertaken. However, we note that the majority of the forecast expenditure for low volume connections is expected to occur within the first two years of the next regulatory control period. As such, it is to be expected that the projects would be more certain than if they were scheduled to be undertaken in the latter part of the next period.

Therefore, on balance, and in the context of a total forecast for connections, we are satisfied that Powercor's forecast for low volume connections is a realistic expectation

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202 Powercor, *2016–20 Price Reset Regulatory Proposal*, p. 125.

203 Powercor, *2016–20 Price Reset Regulatory Proposal*, p. 123.

204 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, p. 79.

205 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, p. 79.

206 AER*, Information Request to Powercor IR# 012*, 9 July 2015.

207 AER*, Information Request to Powercor IR# 012,* 9 July 2015.

of the required expenditure. We have therefore included this amount in alternative capex estimate.

Table 6.16 compares Powercor's proposal with the actual expenditure over the 2011–15 regulatory control period for the low volume connection categories.

Table 6.16 Powercor low volume connections ($2015/16, million, excluding overheads)

	2016	2017	2018	2019	2020	Total
Gross connections capex	26.9	31.3	11.4	7.4	7.4	84.4
Customer contributions	9.6	12.8	3.8	2.3	2.3	30.7
Net connections capex	17.3	18.5	7.6	5.1	5.1	53.7

Source: AER Analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation.xlsx.

Note: Excludes recoverable works, gifted assets and escalators.

Customer Contributions

When a new customer connects to the network, it is required to provide a contribution towards the cost of the connection assets. This contribution can be monetary or in contributions (gifted assets). In addition, a new customer is able to select a provider other than Powercor to construct the new connection assets. Following construction, Powercor pays a rebate to the customer equal to the value of what it would have charged to construct the asset and assumes responsibility for its future maintenance. Powercor's forecast for customer contributions is set out in Table 6.17.

Table 6.17 Powercor customer contributions ($2015/16)

	2016	2017	2018	2019	2020
Cash contributions	61.2	68.0	51.0	47.3	47.2
Gift Assets	24.9	24.9	24.9	24.9	24.9
Rebates	-16.7	-16.7	-16.7	-16.7	-16.7
Total Contributions	69.5	76.2	59.3	55.6	55.4

Source: AER Analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation

Note: Cash contribution includes recoverable works.

In this section we consider Powercor's application of the relevant guideline to forecast the customer contributions. We then consider the forecast of contributions, by the following categories:

- cash contribution associated with high and low volume works
- gifted assets, and
- rebates for work undertaken by third parties.

We note Powercor has included in its forecast customer contributions an amount of $60 million ($2015/16) for the Victorian Government's Powerline Fund for the replacement of assets in high risk bushfire areas. We are satisfied that the Victorian Government has provided sufficient surety of the continuation of this program into the forecast period. We have therefore included an amount for this program in our forecast of customer contributions.

Connection Charge Guideline

In Victoria, the Essential Services Commission's (ESCV) Guidelines 14 and 15 determine the customer connection charges. In its proposal, Powercor noted it was unclear at this stage whether it will be required to comply with the AER's Connection Charge Guideline or the ESCV's Guidelines 14 and 15 when determining connection charges, including capital contributions. We note that in June 2012, the Victorian Government announced it will defer its transition to the National Energy Customer Framework (NECF).[208] A transition to the NECF would give effect to Powercor needing to comply with the AER's Connection Charge Guideline.

We addressed this in our framework and approach for the 2016–20 regulatory control period Powercor determination where we noted that the size of customer contributions will be calculated as provided for in Guideline 14 or, if Chapter 5A applies, the AER's connection guideline.[209]

The CCP in its submission noted:

> Victoria has not yet ratified NECF so the connections policies embedded in NECF do not apply to the Victorian DNSPs and should use the ESCV guidelines for new connections. The AER has a guideline for new connections, developed from NER Chapter 5A and the F&A seems to imply that ESCV guideline should apply. Despite this, some of the DNSPs. seem to indicate that they have followed the AER guideline. This issue needs to be clarified.[210]

Powercor notes in its proposal that in calculating the customer contributions for the capital expenditure forecasts, Powercor has assumed that Guidelines 14 and 15 will continue to apply.[211] We are satisfied that Powercor has prepared its forecasts in accordance with the prevailing connection charge guideline.

Cash contributions for high and low volume works

Figure 6.15 shows the trend in Powercor's actual and forecast high volume cash customer contributions.

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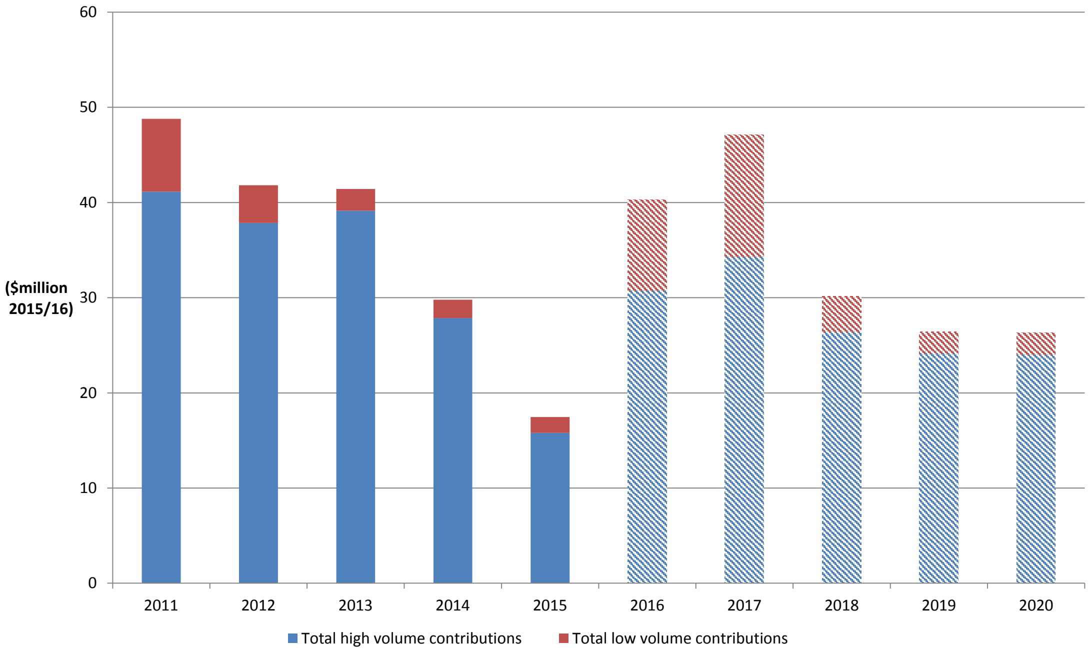
[208] For more information see: http://www.energyandresources.vic.gov.au/energy/about/legislation-and-regulation/national-energy-customer-framework.

[209] AER, *Final Framework and approach for the Victorian Distributors Regulatory Period commencing 1 January 2016*, 24 October 2014, p. 42.

[210] Consumer Challenge Panel 3 – Victorian DNSPs revenue reset comments on DNSPs proposal, p. 54.

[211] Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure,* April 2015, p. 111.

Figure 6.15 Powercor cash contributions by connection type - historic, actual and proposed for 2016–20 regulatory control period ($2015/16, million)



Source: Powercor, Response to information request 012.

We note that actual customer contributions have been steadily declining over the 2011-14 period before a significant uptick in 2015. As noted previously, the timing mismatch whereby Powercor submits its regulatory proposal before the calendar year 2015 is complete means that this 2015 year is an estimate.[212] For the reasons discussed above we are not satisfied that the 2015 year can be used to accurately gauge the trend in customer contributions.

Comparing customer contributions for the 2011-14 period with Powercor's forecast for the 2016–20 regulatory control period, we note that the forecast represents, on average, a 19 per cent decrease in the amount of cash customer contributions.[213]

We note that this trend is different to the one observed for the other Victorian DNSPs. We note that another Victorian DNSP, Jemena is forecasting an increase in the proportion of gross connections capex being recovered through customer contributions.[214] We consider the drivers behind this increase relate to:

- the inclusion of income tax liabilities in the incremental costs incurred when a contribution is received, and

212 See discussion of options analysis in our assessment of Powercor's low volume forecast.

213 When comparing the 2011-14 annual average with the annual average being forecast for the 2016–20 regulatory control period.

214 AER, *Jemena Preliminary Determination, Attachment 6 Capital Expenditure*, 29 October 2015.

- a forecast fall in average customer load consumption, this has the effect of reducing the revenue recovered through network tariffs.

We note in Jemena's case it has adopted a similar approach to Powercor by deriving its contribution forecast by sampling historical contribution rates.[215] However, the sampling approach used by Jemena includes a number of years, in contrast to Powercor's approach which relies on a sample from 2013 only, as discussed below.

In determining whether we are satisfied the Powercor forecast meets the capex criteria, we have assessed the methodology used to produce the forecast below.

Powercor forecast methodology

Powercor's forecast of customer contributions relies on multiplying a derived contribution rate to the high and low volume gross connection capex forecasts.[216] The model Powercor submitted accompanying its regulatory proposal that takes a sample of 262 customer projects on Powercor's network in 2013 to calculate the contribution rate. The sample projects are from across various internal reporting categories or function codes of connection projects.[217]

We sought further information from Powercor to clarify the rationale behind the selection of the sample. In particular, we sought clarification on why the sample of was restricted to projects undertaken in 2013 as well how the sample relates to the forecast projects.[218] In its response, Powercor noted that the model was originally built in the latter part of 2013 and as such the sample of projects was selected from 2013. Powercor also noted that the year does not have an impact on the modelling.[219] Powercor referred to the following explanation:

> The sample selection was based on typical projects within each category and is representative of history. The size of the sample is deemed adequate for the projection of projects going forward as it represented the same customer contribution percentage for that year. The details of each sample projects such as incremental load, customer directly attributed cost and MCR level were used to complete a detailed. analysis such that there are no outliers that could unduly influence the contribution rates. This analysis was then used to project contribution rates going into 2016–20.
>
> There is no reason for us to believe that future mix of projects will be vastly different from the past mix.[220]

We are not satisfied that Powercor has demonstrated that the sample used to generate the contribution rate is reflective of the projects included in its forecast. In particular, as

[215] AER, *Jemena Preliminary Determination, Attachment 6 Capital Expenditure*, 29 October 2015.

[216] Powercor, *Regulatory Proposal 2016–20,* April 2015*,* p. 138.

[217] Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure,* April 2015, p. 110.

[218] AER, *Information request to Powercor IR# 012*, 9 July 2015.

[219] Powercor*, Response to AER information request IR# 012*, 24 July 2015.

[220] Powercor*, Response to AER information request IR# 012*, 24 July 2015..

we note above, the drivers of customer initiated work can change across time and we would expect a sampling approach to select projects across a number of years.

We have instead included in our alternative capex estimate an amount which trends forward the average of high volume cash contributions to Powercor's network over the 2011-14 period. We discuss the basis of our alternative estimate in the section B.3.3. In addition, we note that this trending approach has been used by Powercor for other contribution categories. As we set out below, we consider this is an appropriate approach and we have included those forecasts in our preliminary decision.

Powercor's cash contribution forecast for low volume work is largely associated with major projects in years 2016 and 2017. Given this, we have not sought to apply a trending approach to this category. Consistent with our decision on the gross connections expenditure for low volume work, we have accepted Powercor's cash contribution forecast for low volume work. Table 6.18 compares Powercor's proposal with the actual customer contributions over the 2011–15 regulatory control period.

Table 6.18 Powercor cash contribution actual and proposed ($2015/16, million)

	11-14 average	2016	2017	2018	2019	2020
High volume	36.5	30.7	34.3	26.3	24.1	24.0
Low volume	n/a	9.6	12.8	3.8	2.3	2.3
Powercor forecast		40.3	47.1	30.1	26.4	26.3
AER Decision		46.1	49.3	40.3	38.8	38.8

Source: AER Analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation.xlsx

Note: Excludes recoverable works, gifted assets and rebates.

Gifted assets and rebates

As outlined above, new customers can choose a third-party provider to build their connection assets. Customers pay the third party provider for the cost of the asset, but receive a rebate from Powercor equal to the value of Powercor undertaking the work themselves. The aim of this process is to encourage competition for the provision of connection services. Powercor's forecast for the rebates it is likely to pay out and the assets it is likely to be gifted is set out in Table 6.19.

Table 6.19 Powercor gifted assets and rebates forecast ($2015/16, million)

	11-14	2016	2017	2018	2019	2020
Gifted Assets	24.9	24.9	24.9	24.9	24.9	24.9
Rebates	16.7	16.7	16.7	16.7	16.7	16.7

Source: AER Analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation.xlsx.

As shown, Powercor has forecast these amounts based on an average of the actual value of rebates and gifted assets in the years 2011-2014. This is the same methodology as we have used in forming substitute estimates in other areas of our connection expenditure decision.

Based on the reasons set out in section B.3.3, we are satisfied that this trending approach is an appropriate method for forecasting connections and contributions in the current circumstances and we have included this amount in our preliminary decision.

AER Preliminary Decision on Contributions

The sections above have considered cash contributions, gifted assets and rebates. Table 6.20 below brings these together and sets out the contributions we have included in our Preliminary Decision.

Table 6.20 AER Customer contributions substitute estimate ($2015/16, million)

	2016	2017	2018	2019	2020
Cash contributions	67.0	70.2	61.2	59.7	59.7
Gift Assets	24.9	24.9	24.9	24.9	24.9
Rebates	-16.7	-16.7	-16.7	-16.7	-16.7
Total Contributions	75.2	78.4	69.4	67.9	67.9

Source: AER Analysis, Powercor PAL PUBLIC MOD 1.18 - PAL Capex consolidation.

Note: Cash contribution includes recoverable works.

B.4 Forecast repex

Repex is driven by the inability of network assets to meet the needs of consumers and the overall network. The decision to replace can be based on cost, quality, safety, reliability, security, or a combination of these factors. In the long run, a service provider's assets will no longer meet the requirements of consumers or the network and will need to be replaced, refurbished or removed.[221] Replacement is commonly driven when the condition of the asset means that it is no longer economic or safe to be maintained. It may also occur due to jurisdictional safety regulations, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network. Technological change may also advance the timing of the replacement decision and the type of asset that is selected as the replacement.

[221] Assets may also be replaced due to network augmentation. In these cases the primary reason for the asset expenditure is not the replacement of an asset that has reached the end of its economic life, but the need to deploy new assets to augment the network, predominantly in response to changing demand.

Electricity network assets are typically long-life assets and the majority will remain in use for far longer than a single five year regulatory control period. Many of these assets have economic lives of 50 years or more. As a consequence, a service provider will only replace a portion of its network assets in each regulatory control period. The majority of network assets will remain in commission well beyond the end of any single regulatory control period.

Our assessment of repex seeks to establish the portion of Powercor's assets that will likely require replacement over the 2016–20 regulatory control period, and the associated expenditure. Powercor's forecast of repex includes estimates of the capex it considers necessary to comply with safety obligations implemented in response to the 2009 Victorian Bushfires Royal Commission (VBRC). Powercor also included estimates in its augex forecast for VBRC. Our analysis of Powercor's repex and augex forecast for VBRC is included together at appendix B.5, as the expenditure driver is related. The repex aspects are then included in the total repex forecast, while the augex aspects are included in the augex forecast at appendix B.2.

B.4.1 Position

We do not accept Powercor's proposed repex of $722 million. We have instead included in our alternative estimate of overall total capex, an amount of $644 million ($2015) for repex, excluding overheads. This is 89 per cent of the amount that Powercor proposed. We are satisfied that this amount reasonably reflects the capex criteria.

B.4.2 Powercor's proposal

Powercor's proposed forecast repex is $722 million. Powercor submitted that this expenditure is driven by:[222]

- increased replacement of poles and cross-arms to mitigate the increasing failure rate
- re-commencement of the replacement of high-voltage overhead conductor program
- additional replacement of transformers and switchgear in the network given the Health Indices are forecasting increased network risk.

B.4.3 AER approach

We have applied several assessment techniques to assess Powercor's forecast of repex against the capex criteria. These techniques were:

- analysis of Powercor's long term total repex trends
- predictive modelling of repex based on Powercor's assets in commission

222 Powercor, *Regulatory Proposal 2016–2020*, April 2015, p. 112.

- technical review of Powercor’s approach to forecasting, costs, work practices and risk management
- consideration of various asset health indicators and comparative performance metrics.

We primarily use our predictive modelling to assess approximately 63 per cent of Powercor’s proposed repex in combination with the findings of Energeia's technical review. For the remaining categories of expenditure, we may use predictive modelling where suitable asset age data and historical expenditure are available, but will also rely on analysis of historical expenditure. We explain the reasons for this approach in the “other repex categories” section below.

We note that the assessment of long term trends, the consideration of asset health indicators and comparative metrics are also considered as part of our assessment process. However, we have not ultimately used these to reject Powercor’s forecast of repex or develop our alternative estimate. Our findings from these assessment techniques are consistent with our overall conclusion.

In its report on the Victorian distributor’s the CCP considered that the suite of approaches we use in our assessment or repex provides a much better top down approach to identifying the upper bounds for efficient capex proposals than appears to be the view of the distributors.[223]

Trend analysis

We recognise the limitations of expenditure trends, especially in circumstances where replacement needs may change over time (e.g. a distributor may have a lumpy asset age profile or legislative obligations may change over time). In recognising these limitations, we have used this analysis to draw general observations in relation to the modelled categories of repex, but we have not used it to reject Powercor’s forecast of repex or develop our alternative estimate. However, we have relied on trend analysis to assist our assessment of the unmodelled categories of repex.

Predictive modelling

Our predictive model known as the repex model can be used to predict a reasonable amount of repex Powercor would require if it maintains its current risk profile for condition-based replacement into the next regulatory control period. Using what we refer to as calibrated replacement lives in the repex model gives an estimate that reflects Powercor’s 'business as usual' asset replacement practices. We explain the calibrated replacement life scenario, along with other input scenarios, further below.

[223] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 38.

As part of the 'Better Regulation' process we undertook extensive consultation with service providers on the repex model and its inputs. The repex model we developed through this consultation process is well-established and was successfully implemented it in a number of revenue determination processes including the recent NSW/ACT decisions. It builds on repex modelling we undertook in previous Victorian and Tasmanian distribution pricing determinations.[224] The CCP countered the view of the distributors that there are significant shortcomings in our repex modelling approach. The CCP recognised that predictive modelling is part of our overall approach which also uses other techniques such as trend analysis.[225]

The repex model has the advantage of providing both a bottom up assessment, as it is based on detailed sub-categories of assets using data provided by the service providers, and once aggregated it provides a well-founded high level assessment of that data. The model can also be calibrated using data on Powercor's entire stock of network assets, along with Powercor's recent actual replacement practices, to estimate the repex required to maintain its current risk profile.

We recognise that predictive modelling cannot perfectly predict Powercor's necessary replacement volumes and expenditure over the next regulatory control period, in the same way that no prediction of future needs will be absolutely precise. However, we consider the repex model is suitable for providing a reasonable statistical estimate of replacement volumes and expenditure for certain types of assets, where we are satisfied we have the necessary data. We explain our reasons for this in Appendix E of our preliminary decision. We also note that the service providers (including Powercor) rely on similar predictive modelling to support their forecast amount for repex.

We use predictive modelling to estimate a value of ‘business as usual’ repex for the modelled categories to assist in our assessment. However, predictive modelling is not the only assessment technique we have relied on in assessing Powercor’s proposal. Our other techniques, which are qualitative in nature, allow us to form a view on whether or not ‘business as usual’ expenditure appropriately reflects the capex criteria.

Any material difference from the 'business as usual' estimate could be explained by evidence of a non-age related increase in asset risk in the network (such as a change in jurisdictional safety or environmental legislation) or evidence of significant asset degradation that could not be explained by asset age. Powercor faces a number of new safety obligations arising from the recommendations of the VBRC. These are assessed at appendix B.5 of this preliminary decision.

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224 We first used the predictive model to inform our assessment of the Victorian distributors' repex proposals in 2010. We undertook extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline. We have since used the repex model to inform our assessment of repex proposals for Tasmanian, NSW, ACT, QLD and SA distributors.

225 Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 38.

Technical review

We engaged Energeia to perform a technical review of Powercor’s proposed repex. Energeia assessed Powercor’s approach to forecasting, in particular, whether Powercor’ forecast repex in order to maintain its safety and reliability, or whether it was seeking to improve these outcomes. In doing so, Energeia took account of indicators of safety and reliability, forecast expenditure, and qualitative information from Powercor on the matters it has regard to when forecasting repex. Energeia’s review was limited to the six asset categories included in the repex model.

As set out above, we considered Energeia's findings in assessing whether Powercor’s forecast will allow it to prudently and efficiently maintain the safety and reliability of its network. As all Victorian network businesses have used predictive modelling as part of their initial proposal, this allows us to have confidence that the use of the repex model is suitable in either accepting a network business’s proposal, or in arriving at our alternative estimate.

Asset health indicators and comparative performance metrics

We have used a number of asset health indicators with a view to observing asset health. While providing some context for our decision, we have not relied on these indicators to any extent to inform our alternative estimate, they have provided context for our decision and the findings are consistent with our overall conclusion.

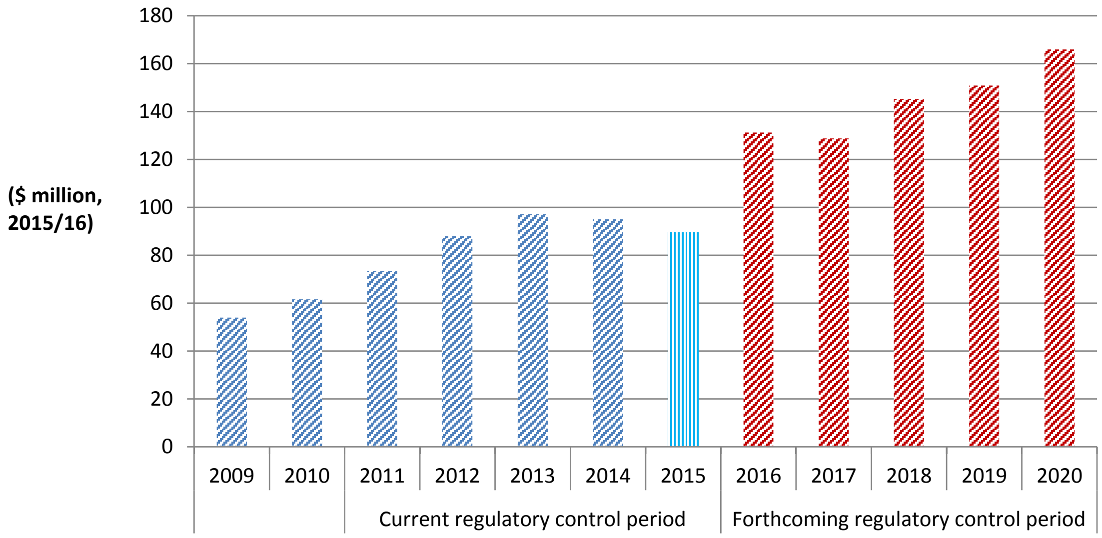
Similar to trend analysis, our use of these high level benchmarks has been to inform the relative efficiency of Powercor’s previous repex. However, we have not used this analysis in rejecting Powercor’s proposal and in developing our alternative estimate. We used this analysis as a cross-check with the findings of other techniques.

B.4.4 AER repex findings

Trends in historical and forecast repex

We have conducted a trend analysis of repex. The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period. Our use of trend analysis is to gauge how Powercor’s historical actual repex compares to its expected repex for the 2016–20 regulatory control period. Figure 6.16 shows Powercor’s repex spend has been trending up with the exception of 2014 and 2015.

Figure 6.16 Powercor - Actual and forecast repex ($ million, 2015/16)



Source: PAL PUBLIC RIN 1.1 Powercor, Vic Reset RIN 2016–20 - Consolidated Information, PAL PUBLIC RIN 1.19 Powercor, 2009-2013 Category Analysis RIN and PAL PUBLIC RIN 1.20 Powercor, 2014 Category Analysis RIN.

When considering the above trend we acknowledge there are limitations in long term year on year comparisons of replacement expenditure. In particular we are mindful that during the 2011–15 regulatory control period, Powercor forecasts to overspend its regulatory allowance for replacements by 1 per cent.[226] Powercor in its proposal noted this expenditure reflects a range of competing factors:

- a higher volume and expenditure on pole replacements undertaken during the period as a result of the higher volume of defects identified by the asset inspection regime than originally forecast;
- a higher volume and expenditure on cross-arm replacements undertaken during the period as a result of the higher defect volumes identified by the asset inspection regime than originally forecast;
- a lower than anticipated volume and expenditure on the proactive overhead conductor replacement works program, as a result of the program being paused due to the uncertainty surrounding the Powerline Bushfire Safety Taskforce's (PBST) requirements for the undergrounding of assets; and
- an unanticipated obligation to install new generation electronic ACRs to SWER lines.

An increasing or decreasing trend does not, in and of itself, indicate that a service provider has proposed repex that is likely to reflect or not reflect the capex criteria. In

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[226] Powercor, *Regulatory Proposal 2016–2020, Appendix E: Capital Expenditure*, April 2015, p. 45.

the case of Powercor, which has proposed an increase in repex from the last regulatory control period, we must consider whether it has sufficiently justified that this increase is required to reflect the capex criteria. We use our predictive modelling, the advice of our consultants, the views of stakeholders, the material put forward by Powercor in support of its forecast, and our consideration of any repex required to meet the new safety obligations arising from the recommendations of the VBRC, to help us form a view on whether Powercor has sufficiently justified its increase in repex from the last period.

Predictive modelling

We use predictive modelling to estimate how much repex Powercor is expected to need in future, given how old its current assets are, and based on when it is likely to replace the assets. We modelled six asset groups using the repex model. These were poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories.

We have sufficient replacement volume, cost and asset age data for these modelled categories at a granular level. This gives us the ability to assess the outcomes of benchmark data across all distributors in the NEM. For other categories, we do not necessarily have sufficient data to allow such comparison, for example, repex without an associated age profile. In this instance, we rely more heavily on other assessment techniques such as business cases and high level justifications put forward by the service providers. However, where we have age and historical volumes, we may still choose to use the repex model to test both the service provider's proposal and our own findings. Our predictive modelling process is described further at appendix E. In total, the assets in these six categories represent 63 per cent of Powercor's proposed repex.

We consider the best estimate of business as usual repex for Powercor is provided by using calibrated asset replacement lives and unit costs derived from Powercor's recent forecast expenditure. This estimate uses Powercor's own forecast unit costs, but it effectively 'calibrates' the proposed forecast replacement volumes to reflect a volume of replacement that is consistent with Powercor's recent observed replacement practices, rather than relying on a purely aged based indicator. We have assessed this finding in the context of our technical review before forming a view as to the appropriate repex component of capex for Powercor. We set out below our views on their suitability for use in our assessment.

In total for all six modelled categories we have included an amount of $375 million ($2015–16) in our alternative estimate of total forecast capex, compared to Powercor's forecast of $452 million for these categories. We have had regard to the outcome and the findings of the technical review in considering whether it is appropriate to forecast repex on the basis of a business as usual estimate, or whether Powercor has provided sufficient evidence to suggest that its replacement needs are higher in the next period.

Our technical consultant, Energeia, assessed Powercor's approach to forecasting, In particular, whether Powercor's forecast repex was necessary in order to maintain its safety and reliability, or whether it was seeking to improve these outcomes. Energeia states that Powercor claims its repex focuses on the drivers of asset failure more than the consequences of those failures. While Powercor provided evidence of policies and procedures for trading-off on the basis of risk adjusted costs, it did not evidence that this process was followed by providing a ranking of potential safety repex options by category. Energeia could not conclude that Powercor's proposed repex was prudent and efficient due to the number and degree of significant risks and/or issues identified.[227]

The CCP stated that it is consumer experience that should be the core drive of repex levels, concluding that consumers are satisfied with current levels of repex and therefore they see no need for a step increase in repex. It considered that the distributors' proposed overall level of repex is not justified as current reliability levels do not suggest there is a need to increase repex. The CCP was of the view that the residual ages of the distributors' assets have maintained or improved over time, opex spending has been increasing, and condition based assessments appear subjective and likely conservative.[228]

Model inputs

The repex model uses the following inputs:

- The asset age profile input is the number of assets in commission and when each one was installed.
- The replacement life input is a mean replacement life and standard deviation (i.e. on average, how old assets are when they are replaced).
- The unit cost input is the unit cost of replacement (i.e. on average, how much each asset costs to replace).

In appendix E, we describe using the repex model to create three scenarios. In each of the three modelling scenarios (base case scenario, calibrated scenario and benchmark scenario) we combined different data for the final two inputs.

Under all scenarios, the first input is Powercor's asset age profile (how old Powercor's existing assets are). This is a fixed input in all three scenarios.

The second and third inputs can be varied by using different input assumptions about:

- how long we expect an asset to last before it needs replacing; and
- how much it costs to replace it.

The repex model takes the replacement life input for each asset category and applies it to the actual age of the assets in each asset category. In doing this it calculates how

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227 Energeia, *Review of Victorian Distribution Network Service Provider's Initial Replacement Capex Proposals 2016–2020*, September 2015, pp. 32–33.

228 Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, p. 47.

many assets are likely to need replacement in the near future.[229] The model then applies the unit cost input to calculate how much expenditure is needed for that amount of replacement in each asset category. This is aggregated to a total repex forecast for each of the next 20 years.

In the remaining part of this section, we outline the replacement lives and unit cost inputs we tested in the repex model to assess Powercor's proposed repex. As part of our assessment, we compared the outcomes of using Powercor's estimated replacement lives and its unit costs, both forecast and historical, with the replacement lives and unit costs achieved by other NEM distributors. We also used the repex model to determine calibrated replacement lives that are based on Powercor's past five years of actual replacement data (its recent replacement practices). These reflect Powercor's immediate past approach to replacement.[230] We calculated historic unit costs by dividing historic expenditure by historic volumes and forecast unit costs by dividing forecast expenditure by forecast volumes. Detail on how we prepared the model inputs is at Appendix D of this preliminary decision.[231]

Our repex modelling assessment is exclusive of expenditure required for VBRC repex, which Powercor has identified in its 'other' repex category.

'Business as usual' repex

The calibrated asset life scenario gives an estimate based on Powercor's current risk profile, as evidenced by its own replacement practices. Our estimate brings forward the current replacement practices that Powercor has used to meet the capex objectives in the past. Calibrated replacement lives use Powercor's recent asset replacement practices to estimate a replacement life for each asset type. These replacement lives are calculated by using Powercor's past five years of replacement volumes, and its current asset age profile (which reveals how many, and how old, Powercor's assets are), to find the age at which, on average, Powercor replaces its assets.

The calibrated replacement life may be different to the "nameplate" or nominal replacement age of the asset (which we considered under the "base case" scenario). Powercor reports these expected asset lives as part of its RIN response. However these reflect expectations of lives from engineering and manufacturing information, rather than observations of the economic lives achieved on the network. Using the lives provided in the RIN response in the repex model provides estimates of repex that greatly exceed Powercor's own expectation of its replacement needs over the next period. From this, we observe that, in general, these technical estimates of asset life tend to understate the actual lives achieved on the network, and are a conservative

229 The repex model predicts replacement volumes for the next 20 years.

230 For discussion on how we prepared each of the inputs see AER, *Preliminary decision, Energex distribution determination Attachment 6: Capital expenditure*, *Appendix E* :*Predictive modelling approach and scenarios*, *May 2015.*

231 AER, *Preliminary decision, Energex distribution determination, Attachment 6: Capital expenditure, appendix E*, May 2015.

estimate of the observable economic life of the assets, when compared to the calibrated replacement life.

The calibrated asset life scenario has been our preferred modelling scenario in recent reviews of other service providers.[232] This is because we considered the calibrated replacement lives formed the basis of a business as usual estimate of repex, as they are derived from the service provider's actual replacement practice observed over the past five years and the observable (or revealed) economic replacement lives of the assets.

A service provider decides to replace each asset at a certain time by taking into account the age and condition of the asset, its operating environment, and its regulatory obligations. If the service provider is currently meeting its network reliability, quality and safety requirements by replacing assets when they reach a certain age, then by adopting the same approach to replacement in future they are likely to continue to meet its obligations. Consequently, the estimates derived from the model reflect the replacement practices that Powercor has used in the past to meet the capex objective of maintaining the safety and reliability of the network.

If underlying circumstances are different in the next regulatory control period, then this approach to replacement may no longer allow a service provider to meet its obligations. We consider a change in underlying circumstances to be a genuine change in the underlying risk of operating an asset, genuine and justifiable evidence that there has been a change in the expected non-age related condition of assets from the last regulatory control period, or a change in relevant regulatory obligations (e.g. obligations governing safety and reliability).

If we are satisfied that there is evidence of a change in a service provider's underlying circumstances, we will accept that future asset replacement should not be based on a business as usual approach. This means that where there is evidence that a service provider's obligations have changed then it may be necessary to provide a forecast of repex different to the business as usual estimate. This alternative forecast would be required in order to satisfy us that the amount reasonably reflects the capex criteria.

Where there are new obligations (or fewer obligations) we can use the service provider’s past practices as a first step before estimating the impact of the change. The new safety obligations arising from the VBRC recommendations represent a change in circumstances from the ‘business as usual’ practices of the last period. The impact of these are set out in appendix B.5 and, as noted above, are included within our consideration of total repex. We do not consider that Powercor has identified other new obligations for the next regulatory control period that cannot be captured by adopting the ‘business as usual’ forecast of repex. Consequently, we have relied on our estimate from the calibrated repex model, in combination with our findings in relation to

232 See final decisions for NSW (April 2015) and Queensland and South Australian distributors (October 2015).

the new safety obligations, in assessing whether Powercor proposed repex reasonably reflects the capex criteria.

The CCP highlighted variances across distributor's stated asset lives and anomalies in the Victorian distributors' data. The CCP supported a more standard approach to asset lives across the distributors. It noted the average residual ages of the distributors' assets have been maintained or improved over time. The current levels of capex have not resulted in a deterioration of residual asset lives, which the CCP considers implies there is no need for an increase in repex over current expenditure levels.[233] Bendigo Manufacturing Group also raised concerns about the asset lives distributors were using to justify the proposed increases in repex.[234] We consider these views support our use of the calibrated scenario as the asset lives are derived from a distributor's revealed replacement approach.

The Victorian Greenhouse Alliance was concerned with the significant increases to repex the Victorian distributors are proposing. It considered this was concerning given that over-investment in the networks over recent regulatory control periods has led to excess levels of network capacity and declining network utilisation. It is also found it concerning that high revenue proposals were being put forward at a time of declining capacity utilisation, a reduced average asset age for most asset categories, static or falling demand and consumption, and reductions in the excessive reliability standards.[235]

As noted above, we are satisfied that with the exception of additional funding to address the impact of new safety obligations a business as usual approach to repex will provide Powercor with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system.

That said, we have also considered whether the service provider's replacement practices from the last regulatory control period did more than maintain safety, reliability and security of the distribution system, such that applying the business as usual approach for asset replacement may result in replacement practices that provide for expenditure over and above what is necessary to satisfy the capex objectives. In considering the efficiency of recent replacement practices, we place some weight on the ex-ante capex incentive framework under which the service providers' operate.

There are incentives embedded in the regulatory regime that encourage a service provider to spend capex efficiently (which may involve spending all of the allowance, less or more, in order to meet the capex objectives). A service provider is only funded in the regulatory control period to meet the capex allowance. The service provider

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[233] Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, August 2015, pp. 48, 50–51.

[234] Bendigo Manufacturing Group, *Submission on Powercor's proposal*, April 2015, p. 1.

[235] Victorian Greenhouse Alliance, *Submission to AER: Local Government Response to the Victorian Electricity Distribution Price Review (EDPR) 2016–20*, July 2015, p. 7.

keeps the funding cost obtained over the regulatory control period of any unspent capex for that period, and, conversely, bears the funding cost of any capital expenditure that exceeds the allowance. In this way, the service provider has an incentive to spend efficient capex, or close to the allowance set by the regulator, as it is essentially rewarded (penalised) for any underspend (overspend). This provides some assurance that a service provider reacting to these incentives will undertake efficient capex to meet the capex objectives. This means that to some extent we can rely on the ex-ante capex framework to encourage the service providers to engage in efficient and prudent replacement practices.

Going forward, this incentive will be supplemented by a Capital Expenditure Sharing Scheme, which will provide a constant incentive to spend efficient capex over the regulatory control period, as well as the ability to exclude capex overspends from the RAB as part of an ex-post review. These additional arrangements will provide us with greater confidence that the service provider’s past replacement practices are likely to reflect efficient and prudent costs, such that business as usual asset replacement approach is likely to be consistent capex objectives.

Possible future rule changes may also extend the regulatory investment test for distribution (RIT-D) to repex. Such a change would make it incumbent upon the service provider to develop credible options for asset replacement, including considering whether the asset life could be extended or whether the asset could be retired rather than replaced.

Finally, the collection of a longer period of data on changes in the asset base as part of our category analysis RIN will provide us with further information into the service providers' asset replacement practices over a longer period of time. This will further inform our understanding of business as usual replacement practice to estimate repex. More time series data would also strengthen our ability to use benchmarked information (e.g. asset life inputs) in the repex model in the future, which is intended to drive further efficiency in replacement expenditure.

Calibrated scenario outcomes

The calibrated repex model scenario, which was described in the last section, provides an estimate of replacement volumes for the next period. In order to estimate how much repex is required to replace this estimated volume of assets, we must multiply the volume by the cost of replacing a single asset (unit cost). We tested two unit cost assumptions, based on data provided by Powercor:

- Powercor’s own historical unit costs from the current regulatory control period. These reflect the unit costs Powercor has incurred over the last five years (revealed costs).
- Powercor’s own forecast unit costs for the next regulatory control period. These reflect the unit costs Powercor expects to incur over the next five years.

Applied to the forecast volumes predicted from calibrated replacement lives estimates $375 million using Powercor's historical unit costs and $456 million using Powercor’s forecast unit costs. Powercor's proposed repex forecast is $452 million for the six modelled asset categories.

There is a significant difference between the calibrated scenario outcomes when using Powercor's historical or forecast unit costs, with Powercor’s proposed forecast repex being closer to the forecast unit cost. Powercor's forecast unit costs for the next five years are, on average, higher than its unit costs over the last five years. However, in the absence of a reasonable explanation of why costs would be materially higher, we would not expect forecast unit costs to be higher than historical unit costs given the incentive framework encourages a distributor to become more cost efficient over time.

We also compared Powercor's historical unit costs to benchmark unit costs. These are based on the unit costs of all NEM distributors across the consistent asset categories we use in the repex model, which were provided as part of the category analysis RIN. In summary, we take unit cost observations from across the NEM and find an average unit cost, a lower quartile unit cost, and the lowest unit cost in the NEM for each asset category. When applied in the repex model with calibrated replacement lives, average benchmark unit costs produced an almost identical forecast for the modelled categories of $377 million compared to Powercor’s own historic unit costs ($375 million). This suggested Powercor's historical unit costs are more likely to reflect a realistic expectation of input costs than the unit costs it forecasts.

Accordingly, we adopted Powercor's historical unit costs for the purpose of calculating a business as usual repex estimate. We consider $375 million is the most reasonable "business as usual" estimation of repex. As noted above, we will rely on this outcome and the findings of the technical review in considering whether it is appropriate to forecast repex on the basis of a business as usual estimate.

Testing other model inputs

As outlined earlier (and in appendix E) we used the repex model to create other scenarios combining different input data. In this section we explain how the outcomes of these other scenarios support our conclusion to use the calibrated scenario.

Base case scenario outcomes

Powercor provided its own estimate of asset replacement lives in its RIN response. We test Powercor’s estimated asset lives by using them in the repex model instead of the calibrated lives. We call this modelling scenario the base case. The base case scenario gives repex estimates of $7.5 billion (historical unit cost) and $5.2 billion (forecast unit cost). These forecasts are significantly higher than Powercor’s forecast of $452 million for the six modelled asset groups.

The replacement profile predicted by the repex model under the base case scenario features a sharp step-up in expenditure in the first year of the forecast, which then declines over the remainder of the period. This replacement profile indicates that a significant portion of the asset population currently in commission is much older than would be expected using Powercor’s estimated replacement lives. Using this input causes the model to immediately predict the replacement of this stock of assets. This, in turn, results in a large stock of predicted asset replacements in the first year of the forecast, which then declines over time.

Based on our analysis of the base case scenario outcomes we conclude that Powercor’s estimated replacement lives are not credible or reliable for the following reasons.

First, if Powercor’s actual replacement lives were consistent with their estimated replacement lives, we would not expect to see the observed asset replacement profile. If Powercor’s actual asset replacement profile followed its estimated replacement lives, the older assets would have:

- already reached the end of their economic (replacement) lives and would have already been largely replaced; and
- would therefore not be expected to be in the asset age profile, or be in such insignificant volumes that it would not materially affect the outcome of predictive modelling.

The 'step-up/trend down' replacement profile observed from the base case scenario suggests that a significant proportion of the asset population has survived longer than would be expected using Powercor’s estimated replacement lives. These 'survivor' assets have a material effect on the observed outcome. This outcome suggests that Powercor’s estimated replacement lives are shorter than those it achieves in practice.

Second, further analysis of the base case scenario reveals the replacement life inputs are the main drivers of the base case scenario outcome. Under the calibrated scenario where Powercor’s estimated replacement lives are substituted with calibrated replacement lives the model outputs are $375 million for historical unit costs and $456 million for forecast unit costs. Taken together with the information from our other analytical techniques, and our concerns that Powercor’s estimated replacement lives do not reflect its actual replacement practices, we consider that the estimated replacement life information provided by Powercor will not result in a reasonable forecast of business as usual repex.

Benchmarked scenario outcomes

Benchmarked uncalibrated replacement lives

We developed a series of benchmark replacement lives using the data collected from all NEM distributors in the category analysis RINs. For model inputs we used the average, third quartile (above average), and longest replacement lives of all NEM distributors for each category. We discuss how we prepared this data in appendix E.

As with Powercor's estimated replacement lives, we found using these benchmark replacement lives produced sharp 'step-up/trend down' forecast expenditure, indicating the replacement lives used are likely to be too short for modelling purposes as they predict a large unrealistic 'backlog' of replacement. When used in the model these also produced outcomes higher than Powercor's own forecasts.

Examining distributor’s estimated asset lives across the NEM also illustrates that purely aged-based techniques may tend to over-estimate repex requirements. They do not appear to reflect the actual replacement practices of distributors, or the optimised replacement decisions we would expect of an efficient and prudent operator.

Benchmarked calibrated replacement lives

We developed benchmark calibrated lives by first using the repex model to calculate calibrated lives based on the replacement data from all NEM distributors. For model inputs we again used the average, third quartile (above average), and longest of the calibrated lives of all NEM distributors for each category. We discuss how we prepared this data in appendix E.

When applied to the repex model, compared to both using calibrated replacement lives based on Powercor’s data, and Powercor’s own repex forecast the:

- average benchmark and third quartile calibrated replacement lives produced higher outcomes
- longest benchmark calibrated replacement lives produced lower outcomes.

The calibrated benchmark replacement lives may reflect to some extent the particular circumstances of a distributor and this may not be applicable to each business. These inputs provide us with a check that Powercor's calibrated replacement lives were reasonable against its peer service providers in the NEM.

Benchmarked unit costs

We developed industry benchmark unit costs using the data collected from all NEM distributors in the category analysis RINs. For model inputs we used the average, first quartile (below average), and lowest unit costs of all NEM distributors for each asset category. We discuss how we prepared this data in appendix E.

When applied to the repex model, compared to using Powercor’s unit costs the:

- average benchmark unit costs produced a lower outcome than Powercor’s forecast unit costs, but a slightly higher outcome compared to its historical unit costs
- first quartile and lowest benchmark unit costs produced lower outcomes.

We consider the benchmark unit costs provide a useful comparison with the cost of other distributors in the NEM.

Powercor’s predictive modelling

Powercor submitted its own predictive modelling to support its proposed repex. We consider that Powercor’s repex modelling is not appropriate to predict a business as usual amount of repex. This is because the asset lives Powercor uses in its modelling are in some cases not calibrated to its recent replacement practices. It is not transparent how Powercor derived these lives, many of which are shorter than the calibrated lives we derive from Powercor’s data. It is also unclear why Powercor did not model some asset categories which appear to have sufficient data to be modelled.

Powercor considered a weakness of our approach is the use of history to calibrate the average replacement lives of assets across the business.[236] Powercor submitted a report by Jacobs which we respond to in the remainder of this section.[237]

We reviewed the submissions of Powercor and Jacobs and continue to consider that predictive modelling is a useful and important technique when assessing Powercor's forecast of repex against the capex criteria. Our predictive modelling approach is well established having been used by us in previous distribution determinations and by other regulators.[238] It has been refined following extensive consultation as part of the Better Regulation program. It was clear from our engagement with stakeholders in that process that calibration is understood to be an integral part of good practice in repex modelling for the very reason that it utilises updated data provided by the business being regulated. It is not an arbitrary process or one which involves manipulation to arrive at a pre-determined outcome. It is a systematic process with a transparent purpose.

Calibration Process Inputs

Jacobs submitted that age is not a sufficient and accurate predictor of replacement and that the model fails to make allowance for covariates such as reliability, obsolescence and asset condition.[239] The use of calibrated replacement lives captures Powercor's recent replacement practices, which can account for other relevant factors and not just the age of all its assets in commission. Calibration using actual past replacement practices reflects the factors (including age and condition) that drove replacement in the previous regulatory control period. Further, we recognise that some assets may be better considered outside of the model for a variety of reasons. We discuss our approach to un-modelled assets later in this appendix.

Jacobs also submitted that future replacement needs cannot be predicted by looking at recent past investment and expenditure.[240] However, we consider that Jacob's understanding in this respect misinterprets the workings of the model. Using calibrated replacement lives in the repex model is not trending forward past expenditure or volumes. It is trending forward Powercor's approach to replacement, given its current stock of assets in commission and asset age profile to come to a view on future needs. It is akin to maintaining a business as usual approach in relation to necessary replacement expenditure in the next period. We further assess whether there is evidence that the service provider requires a different forecast to meet the capex criteria through our application of other assessment techniques.

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236 Powercor, *Regulatory Proposal 2016–2020*, April 2015, p. 115.

237 Jacobs, *Regulatory Submission, Powercor Repex Modelling Review*, April 2015, pp. 8–9.

238 OFGEM, *Strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment*, March 2013, p. 44; AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, October 2010; AER, *Final decision: Aurora Energy distribution determination*, April 2012.

239 Jacobs, *Regulatory Submission, Powercor Repex Modelling Review*, April 2015, p. 8.

240 Jacobs, *Regulatory Submission, ActewAGL Distribution, Focussed Critique of AER's REPEX - 'Calibrated Model'*, April 2015, pp. 1–2.

Population size and asset classes

Jacobs is of the view that the model is not suitable for forecasting low volume-high value asset categories such as power transformers and circuit breakers. Prior to this determination, we engaged in an extensive data collection process with industry as an outcome of the Better Regulation process. Part of this process was defining and collecting information suitable for use in predictive modelling. The full process is set out in the data specification section below. A key consideration of this process was determining a set of asset subcategories that were granular enough to be compared across different service providers. The process involved extensive consultation with service providers and other stakeholders, and the outcome was the sub category list included in templates 2.2 and 5.2 of the reset RIN. Further information on this process is included in the relevant better regulation guidelines and explanatory documentation.[241] Population size is considered in the repex handbook.[242] The repex model uses the entire asset population, in the form of the asset age profile, to derive its estimate.

The degree of confidence from a statistical function is related to population size, with higher populations leading to greater degrees of confidence. Powercor has some asset classes with small populations (smaller than 100 units). However, the asset subcategories with relatively small populations do not make up a significant part of Powercor repex program. Indeed, Powercor either forecast no repex for these assets in the next regulatory control period or a very small amount. Further, for those assets where Powercor forecast repex, the predictive model outputs largely matched Powercor's forecast, and, in aggregate, gave a slightly higher estimate. For these reasons we do not consider it necessary to exclude any assets because of the size of their population.

Normal distribution

Jacobs raised concerns that our use of the repex model with normal distribution probability density functions can produce inaccuracy in forecast estimates.[243] Jacobs prefers applying a Wiebull distribution function because it claims that it is well suited to asset failure profiles and sufficiently flexible to describe the probability of asset failure occurring over time.[244] As part of the Better Regulation process we examined which probability density function was more suitable to simulate the replacement needs of the asset categories. This was extensively consulted with industry stakeholders. As a result we have consistently applied a normal probability distribution to all network businesses.

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241 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

242 AER, *Replacement expenditure model handbook*, November 2013, p. 10.

243 Jacobs, *Regulatory Submission, Powercor Repex Modelling Review*, April 2015, p. 28.

244 Jacobs, *Regulatory Submission, Powercor Repex Modelling Review*, April 2015, p. 28.

Other repex categories

Repex categorised as supervisory control and data acquisition (SCADA), network control and protection (collectively referred to hereafter as SCADA); pole top structures; and assets identified in the "other" category have generally not been included in the repex model in recent decisions. We conducted a qualitative review of Powercor' proposal on these expenditure items and comparison with historical trends. Together, these categories of repex account for $269 million (37 per cent) of Powercor's proposed repex.

As noted in appendix D, we did not consider pole top structures were suitable for inclusion in the model because of their relationship to pole replacement. That is, when a pole is replaced, it usually includes the structure, such that it is difficult to predict the number of structures that will be replaced independent of the pole category. Notwithstanding these concerns, we carried out repex modelling of pole top structures to test whether it supported the increase in replacement proposed by Powercor from the last period. However, we have placed more weight on an analysis of historical repex, trends, and information provided by Powercor in relation to these categories. Our analysis of these is included below.

We consider that the replacement of network assets is likely to be relatively recurrent between periods. We recognise there will be period-on-period changes to repex requirements that reflect the lumpiness of the installation of assets in the past. Using predictive tools such as the repex model allows us to take this lumpiness into account in our assessment. For repex categories we do not model, historical expenditure is our best high level indicator of the prudency and efficiency of the proposed expenditure. Where past expenditure was sufficient to meet the capex criteria it can be a good indicator of whether forecast repex reasonably reflects the capex criteria. This is due to the predictable and recurrent nature of repex.[245]

For unmodelled asset categories we consider that if the forecast expenditure for the next period is similar or lower than the expenditure in the last period, the distributor's forecast is likely to satisfy the capex criteria. If forecast repex exceeds historical expenditure, we would expect the distributor to sufficiently justify the increase.

We have accepted Powercor's proposed repex for all these other repex categories. We explain the reasons for our decision below.

Pole top structures

Powercor has forecast $146 million of repex on pole top structures over the 2016–20 regulatory control period. This represents a 31 per cent increase over the amount of repex on pole tops in the 2011–15 regulatory control period.

[245] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 7–9.

Powercor's proposed expenditure is significantly higher than its proposed expenditure. As observed in the network health section below, Powercor's sustained outages due to asset failures have been falling. We do not consider that the change would be required to address an increase in outages due to asset failure.

As noted above, in recent resets, we have chosen not to apply predictive modelling to pole top structures. However, given the significant increase in expenditure proposed by Powercor, we carried out a limited set of calibrated repex model scenarios to test whether they would support Powercor's proposal. The outcomes of the calibrated repex model using historical and forecast unit costs were $94 million and $95 million respectively. These are both lower than Powercor's historical repex, and do not suggest that Powercor requires a 31 per cent increase in the next period.

Taking all these factors into account, we are not satisfied that Powercor has justified the need for an increase in expenditure for pole top structures. We consider Powercor's historical expenditure of $111 million reasonably reflects the capex criteria and have included this in our alternative estimate of total forecast capex.

SCADA, network control and protection

Powercor's proposal includes $18 million for replacement of SCADA, network control and protection (collectively referred to as SCADA). This represents a $3 million increase over the 2011–15 regulatory control period. We consider the proposed increase is relatively low in materiality. We are satisfied that Powercor's forecast SCADA repex of $18 million reasonably reflects the capex criteria and have included this amount in our alternative estimate of total forecast capex.

Other repex

Powercor categorised a number of assets under an "Other" asset group in its RIN response. Powercor forecast $105 million of repex for these assets for the 2016–20 regulatory control period.

Excluding the VBRC repex, Powercor's forecast for repex on other assets in the 2016–20 period is slightly lower than what it spent on these categories in the 2011–15 period. We are satisfied that Powercor's forecast repex for other assets of $49 million (when excluding VBRC repex) reasonably reflects the capex criteria and have included this amount in our alternative estimate of total forecast capex. As noted in section B.5, we have accepted Powercor's has to replace a volume of its SWER lines in response to jurisdictional safety obligations arising in response to the recommendations of the VBRC. Given this, we consider Powercor's forecast of $105 million for this category of repex reasonably reflects the capex criteria.

Network health indicators

As noted above, we have looked at network health indicators and benchmarks to form high level observations about whether Powercor's past replacement practices have allowed it to meet the capex objectives. While this has not been used directly either to reject Powercor’s repex proposal, or in arriving at an alternative estimate, the findings are consistent with our overall findings on repex. In summary we observed that:

- the measures of reliability and asset failures show that outages on Powercor's network have been trending downwards
- measures of Powercor’s network assets residual service lives and age show that the overall age of the network is generally reducing. This also suggests that historical replacement expenditures have at least been sufficient to meet the capex objectives
- asset utilisation has reduced in recent years which means assets are more lightly loaded, this is likely to have a positive impact on overall asset condition.

Further, the value of customer reliability has recently fallen in Victoria. Other things being equal, these falls should result in the deferral of repex as the value customers place on reliability for replacement projects has fallen.

The above indicators generally suggest that replacement expenditure in the past period has been sufficient to allow Powercor to meet the capex objectives. This is consistent with our overall findings on repex from our other assessment techniques.

The asset health indicators are discussed in more detail below.

Trends in reliability and asset failure

Asset failure is a significant contributor to the volume of sustained interruptions on Powercor’s network. Table 6.21 shows that, over the 2009–14 period 37.4 per cent of total interruptions on Powercor’s network were caused by the failure of assets.[246]

Table 6.21 Powercor - contribution of asset failures to non-excluded sustained interruptions

	2009	2010	2011	2012	2013	2014
Sustained interruptions caused by asset failures	41%	40%	36%	35%	34%	37%

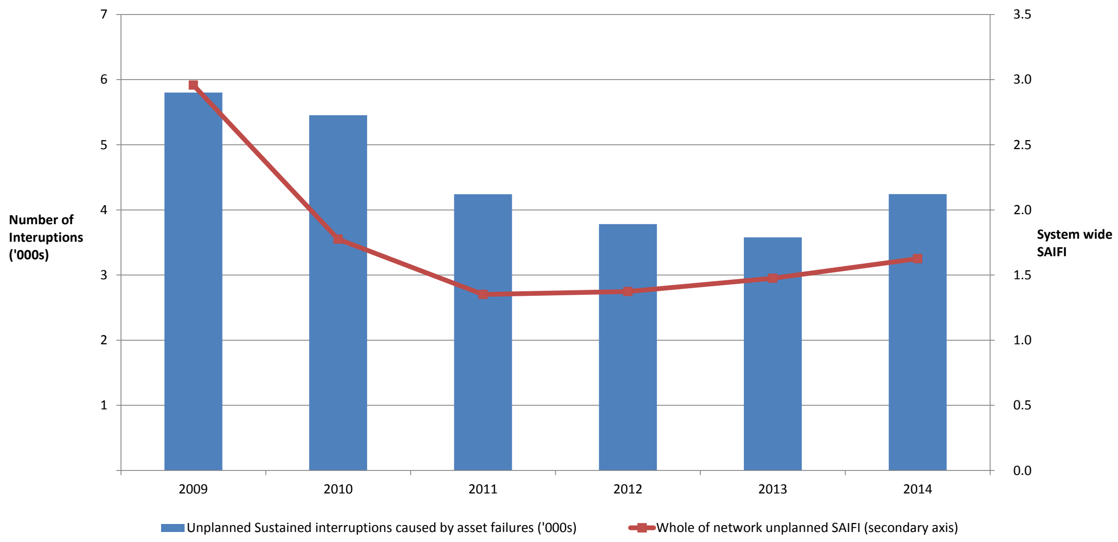
Source: Powercor- CA RIN – 6.3 Sustained Interruptions.

Figure 6.17 compares sustained interruptions caused by asset failure with the System Average Interruption Frequency Index (SAIFI), which is an aggregate measure of the frequency of sustained interruptions on the network.[247]

[246] These measures do not include planned outages, momentary outages, major event days and excluded events.

[247] SAIFI: The total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.

Figure 6.17 Relationship between system wide SAIFI and non-excluded interruptions caused by asset failures



Source: Powercor- CA RIN – 6.3 Sustained Interruptions and EBT RIN - Whole of network unplanned SAIFI

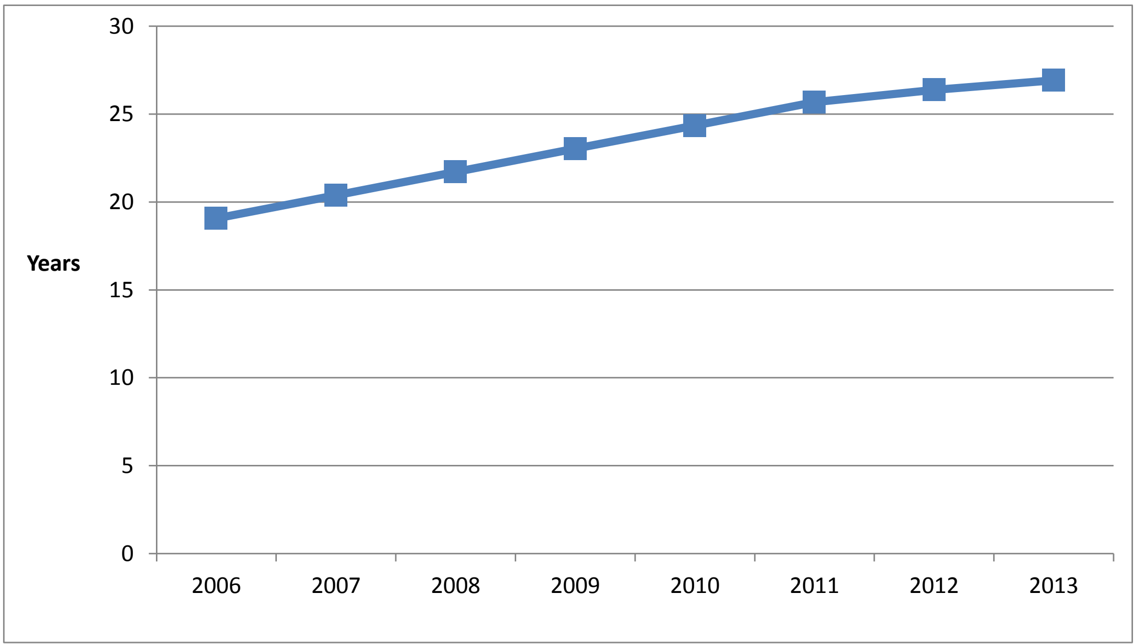
Figure 6.17 shows Powercor's outages due to asset failures have generally been declining across time and its SAIFI has also been improving. The overall improvement in both of these measures indicates that the replacement practices from the last period have been sufficient to meet the capex objectives.

Trends in the remaining service life and age of network assets

Another factor which we have considered when assessing Powercor's repex requirements for the 2016–20 period is the trend in Powercor's residual asset life across time. We are satisfied that residual service life is a reasonable high-level proxy for asset condition. Asset condition is a key driver of replacement expenditure.

Figure 6.18 shows that Powercor's residual asset lives for network assets have been steadily increasing since 2006. This means that, on average, Powercor's network assets are getting younger.

Figure 6.18 Powercor estimated residual service life network assets



Source: Powercor- EBT RIN - 4. Assets (RAB) - Table 4.4.2 Asset Lives – estimated residual service life (Standard control services) Network assets: Overhead network assets < 33kV, Underground network assets < 33kV, Distribution substations (incl transformers), Overhead network assets ≥ 33kV, Underground network assets ≥ 33kV, Zone substations and transformers

We acknowledge limitations exist when using estimated residual service life to indicate the trend in the underlying condition of network assets. Large volumes of network augmentation and connections can result in a large stock of new assets being installed in the network, which may bring down the network's average age. In this way, the residual service life of the assets may increase without necessarily addressing any underlying asset condition deterioration.

Noting the above, the steady increase in the trend in residual lives (where age is a proxy for asset condition) suggests that the health of Powercor's asset base has at least been maintained.

Asset utilisation

We consider the degree of asset utilisation can impact asset condition for certain network assets. As set out in the augex section appendix B.2, we note Powercor has experienced a steady decrease in utilisation levels at its zone substations between 2010 and 2014. Powercor undertook zone substation augmentation projects between 2010 and 2014 that led to a decrease in the number of substations operating above 60 per cent of their maximum capacity. We note that the flattening of demand between 2010 and 2014 may have contributed to a reduction in the utilisation of the network. As of 2014, there are no substations operating above their maximum capacity.

We are satisfied this demonstrates that Powercor's network has spare capacity in its network based on past investments. All things being equal, we expect a positive correlation between asset condition and lower network utilisation exists for certain asset classes.

However we recognise that:

- The relationship between asset utilisation and condition is not uniform between asset types. For example; poles and fuses.
- The relationship is not necessarily linear (e.g. condition may not be materially impacted until a threshold point is reached).
- The condition of the asset may be difficult to determine (e.g. overhead conductor). As such early-life asset failures may be due to utilisation or, more commonly, a combination of factors (e.g. utilisation and vibration).

While noting these issues, we consider that Powercor’s asset utilisation has not been high, and we do not expect any material deterioration of Powercor’s network assets is likely to have occurred in recent years due to high utilisation of the assets.

B.5 Victorian Bushfires Royal Commission

B.5.1 Bushfire safety-related capital expenditure

Powercor proposed a forecast of $135.536 million ($2015) for bushfire safety-related capex (excluding overheads and escalation). This is driven by a mandatory bushfire safety mitigation program for the 2016–20 period.

We accept Powercor's proposed $135.536 million ($2015) forecast and have included this amount in their replacement capital expenditure.

In coming to this view, we have assessed the Powercor bushfire safety capex proposals. Based on our assessment, we find that the proposed capex for the bushfire safety programs reasonably reflect the capex criteria and therefore we have included the proposed capex in our estimate of Powercor's capex requirements.

Our assessment of this program is contained in the section below.

This proposed capex amount for the program is incremental to Powercor's business as usual capex related to bushfire risk management.

Table 6.22 sets out the proposed components of the program.

Table 6.22 Powercor's proposed capex for a fire mitigation program ($2015, million, excluding overheads & escalation)

Strategy	Proposed capex
HBRA Armour Rods & Dampers Retrofit	11.041
LBRA Armour Rods & Dampers Retrofit	50.383
LBRA Multi-circuit survey cost	0.970
LBRA Multi-circuit Repairs (Fitting of Spacers)	0.577
HBRA Multi-circuit Rebuilds	1.174
LBRA Multi-circuit Rebuilds	2.604
REFCLs Detailed design	0.410
REFCLs Installation	13.941
VBRC SWER ACRs	54.433
Total	**135.536**

Source: PAL CONFIDENTIAL MOD 1.28 - PAL VBRC capex and contingent projects.xlsm, 'VBRC Capex Summary'.

AER assessment approach

For bushfire safety related capex there are three potential bases for consideration of a funding requirement. These are:

1. Business As Usual (BAU): Capex which we assess along with other capex in attachment 6, which is in addition to business as usual capex. We use the tools outlined in attachment 6 to assess the efficiency of the forecast. These capex projects relate to maintaining the quality, reliability or security of supply of standard control services or the reliability or security of the distribution system through the supply of standard control services or the safety of the distribution system through the supply of standard control services.[248]
2. Approved projects are set out in the companies' Electrical Safety Management Scheme (ESMS) or Bushfire Mitigation Plan (BMP). We rely on Energy Safe Victoria to establish need. We then assess the efficiency of the forecast cost. These projects are assessed in accordance with the capital expenditure objectives to determine if they are necessary to comply with applicable regulatory obligations or requirements associated with the provision of standard control services.[249]

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248 NER, cll 6.5.7(a)(3) & (4).

249 NER, cl. 6.5.7(a)(2).

3. Pending regulations from the Victorian Government which will legislate areas of recommendation 27 of the Victorian Bushfires Royal Commission (VBRC). The timing and scope of the regulations are not yet known and so costs cannot be forecast. We want to provide the distributor with a mechanism to recover the prudent costs associated with any new obligations while ensuring that consumers pay no more than necessary for the implementation of these.

Our first order of assessment is to consider whether a proposed expenditure fits into one of these broad categories. This helps us to determine which are the most appropriate tools to assess whether a proposal satisfies the capital expenditure objectives.[250] We also consider if the amount sought is compliant with the capital expenditure criteria, particularly if the cost is prudent and efficient.[251]

In this assessment we have considered confidential material concerning the individual project estimates. This is contained in the confidential appendix to attachment 6.

Assessment of Powercor's proposal

Based on the evidence submitted by Powercor and other information before us, we are satisfied that the bushfire mitigation program is required to maintain the reliability and safety of the network and to comply with applicable regulatory obligations or requirements and would be a prudent and efficient investment in the network.

In summary, we consider that:

- Powercor's proposed capex is required to maintain the reliability and safety of its network and to comply with applicable regulatory obligations or requirements.
- Powercor's VBRC proposal does not include any BAU capex.
- Powercor's obligations arise from Powercor's Electrical Safety Management Scheme. The scheme includes a mandatory Bushfire Management Plan. This plan incorporates actions to respond to three directions received from Energy Safe Victoria (ESV). The Directions require Powercor to take measures to fit additional vibration dampers, armour rods and line spacers throughout its network by 1 November 2020 and to make extensive modification to the operation of SWER ACRs.
- Powercor's proposed capex is a prudent and efficient investment. The costs to be incurred are derived from actual contract outcomes from a program that commenced in 2011. The volume estimates are derived from the Powercor GIS system and are consistent with the directions issued by ESV and Powercor's Bushfire Mitigation Plan. We consider the estimating methodology to be sound. Accordingly, the resultant cost estimates are a reasonable estimate of the least cost necessary to achieve the capex objectives.

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[250] NER, cl. 6.5.7(a).

[251] NER, cll 6.5.7(c)(1) & (2).

- Powercor has proposed two contingent projects to address future obligations associated with potential regulations to implement recommendation 27 of the VBRC and a third in relation to a potential change in arrangements affecting privately owned electric lines.

For these reasons, we accept Powercor's' proposed capex for the bushfire mitigation program satisfies the capex criteria. Each of these reasons is discussed further below.

Regulatory obligation

Victorian electrical safety framework

In Victoria, the safety obligations of major electricity companies are contained in the Electricity Safety Act 1998 (Vic). Section 99 of this Act mandates that major electricity companies must submit an approved Electricity Safety Management Scheme (ESMS) to Energy Safe Victoria for acceptance.[252] These schemes are regulated by Energy Safe Victoria. Each of the five Victorian distributors is classed as a 'major electricity company' under this Act.

It is compulsory for Powercor to comply with the accepted ESMS for its network.[253] Further, the Act requires that each major electricity company must submit a Bushfire Mitigation Plan for its network to Energy Safe Victoria and must comply with that plan.[254] The Bushfire Mitigation Plan forms part of an accepted ESMS.[255] This legislated requirement applies to the whole of Powercor's network including urban areas of the network. However, we note a major fire in an urban area would be potentially devastating to that area, were it to occur.

On 4 January 2011 Energy Safe Victoria issued two directions under s 141 of the Electricity Safety Act to Powercor. A major electricity company must comply with a direction under s 141 of this Act that applies to it.[256] The first direction required that Powercor inspect all powerlines in its network and fit armour rods and vibration dampers by 1 November 2020 where the existing installation did not conform to the Victorian Electricity Supply Industry standard.[257] The second direction required the fitting of spacers where the existing installation did not conform to the Victorian Electricity Supply Industry standard.[258]

On 5 April 2012 Energy Safe Victoria issued a third direction to Powercor. The direction required that Powercor amend the operation of Automatic Circuit Reclosers

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252 *Electricity Safety Act 1998* (Vic), s. 99.
253 *Electricity Safety Act 1998* (Vic), s106.
254 See, *Electricity Safety Act 1998* s113A, 113B and 113C.
255 *Electricity Safety Act 1998* (Vic), s113D.
256 *Electricity Safety Act 1998* (Vic), s141(4).
257 Energy Safe Victoria, *Direction under section 141(d)(2) of the Electricity Safety Act 1998 - Fitting of armour rods and vibration dampers*, 4 Jan 2011.
258 Energy Safe Victoria, *Direction under section 141(d)(2) of the Electricity Safety Act 1998 - Fitting of spacers*, 4 Jan 2011.

(ACRs) on high bushfire risk days. The direction includes a requirement to develop and implement a supervised program of replacement of ACRs to conform to the new operating requirements.[259]

Two mechanisms exist for a major electricity company to address a safety concern of when it arises. The first is to voluntarily propose to address the safety hazard by including an undertaking in their ESMS or the Bushfire Mitigation Plan to undertake a specific activity to address the hazard. If a proposed change to their ESMS is approved by the safety regulator, the activity becomes an obligation which must be carried out.

The second mechanism is the creation of a new regulatory obligation by the Government or an action by a Government agency under existing legislation. The issuance of a direction by Energy Safe Victoria falls into this category. Powercor's VBRC capex proposal is wholly in response to regulatory obligations imposed by the directions of ESV. The proposal has been assessed on this basis.

We note that Powercor proposed that possible future obligations be managed as contingent projects in the next regulatory control period. We discuss this proposal later in this section.

The mandatory safety obligations of Powercor relate to nine project categories which we now assess:

Powercor proposal

Powercor has VBRC capex as follows:[260]

> *VBRC expenditure is driven by specific obligations that have been imposed, or are anticipated to be imposed, on us by ESV. The obligations relate to the installation of:*
>
> - *armour rods and vibration dampers to specific conductors which is intended to reduce wear on conductors and the effects of wind-induced vibration on powerlines, in accordance with our Electricity Safety Management Scheme (ESMS);*
> - *new generation Automatic Circuit Reclosers (ACRs) to SWER lines to instantaneously detect and turn off power at a fault on high risk fire days, in accordance with our Bushfire Mitigation Strategy Plan (BMP);*
> - *earth-fault limiting equipment to trial the technology for its ability to mitigate bushfires caused by detecting and turning off power at a fault almost instantaneously, in anticipation of a requirement from ESV to install such equipment;*
> - *conduct a survey of multi-circuit lines to assess whether the conductor clearance is sufficient, in accordance with our ESMS; and*

[259] Energy Safe Victoria, *Direction under section 141(2)(d) of the Electricity Safety Act 1998, Installation of ACRs to SWER lines*, 5 April 2012.

[260] Powercor, *Regulatory Proposal 2016–20*, April 2015, p. 142.

- *spacers in aerial lines to maintain conductor clearances and stop conductor clashing in windy conditions, in accordance with our ESMS.*

If a regulatory obligation exists in an ESMS or BMP it follows that the activity is also required to maintain the reliability and safety of the network. Each of these obligations are contained in the Powercor Bushfire Mitigation Plan dated 17 September 2015.[261] Accordingly, Powercor has demonstrated it has an obligation to undertake this work in the next regulatory control period.

We note that the obligation in relation to earth fault limiting equipment is currently confined to the Woodend and Gisborne substations. These projects are the first for Powercor in what is expected to be a major program of installation of similar devices across Victoria. We discuss this further below.

In reaching our conclusion, we have also taken into account the interrelationship between this proposed expenditure and other expenditure proposed by Powercor. We are satisfied this is a discrete program of work that does not fall within Powercor's business as usual level of capex and opex to manage asset fire safety.

We next assess whether the proposed allowance satisfies the capex criteria.[262]

What are armour rods, vibration dampers and spacers?

Armour rods are a fitting used to protect the power conductor from damage due to bending, compression, abrasion and fatigue due to wind-induced vibration and flashovers. They are helical rods wound over the conductor where it sits on an insulator. Vibration dampers are an additional device to reduce fatigue caused through wind-induced vibration. They are often helical rods wound over the conductor a short distance away from the cross arm. Spacers are insulated rods that are tied between the conductors to stop them from clashing in windy conditions.

HBRA Armour rods & vibration dampers retrofit

Powercor initially prepared its forecast for vibration dampers and armour rods in High Bushfire Risk Areas based on based on consideration of its Geographical Information System (GIS). This was documented in its BMP and approved by ESV. The plan has progressed in the current period but the program is incomplete. The residual number of spans to be treated is 18,153. We consider the survey methodology to be sound. As the basis of this forecast is the result of a survey to establish the approved program to complete the works, adjusted for works completed or programmed to be completed in the 2011–15 regulatory control period, we accept this forecast is accurate.

The costs to be incurred for this activity are derived from actual contract rates used by Powercor. We have considered the unit rate. The unitised rate proposed by Powercor is derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work

[261] Powercor, *Bushfire Management Strategy Plan 2014–2019*, 17 September 2015, pp. 22–25.

[262] NER, cll 6.5.7(c)(1) & (2).

specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. On this basis, we accept the Powercor unitised rate is efficient.

Accordingly, the resultant cost estimates reasonably reflect the capex criteria. For HBRA armour rods and vibration dampers we accept Powercor's forecast.

LBRA Armour Rods & Dampers Retrofit

For Low Bushfire Risk Areas (LBRA) Powercor explained how they adapted the forecasting approach used in HBRA as the basis of its forecast as follows:[263]

> *For LBRA, we have again used GIS to assess the characteristics of each span. Given the construction standards of Powercor's network are the same between HBRA and LBRA, we have applied the actual information from the deployment of armour rods and vibration dampers in HBRA to our GIS information for LBRA. For example, this relates to whether an armour rod and/or vibration damper needs to be installed given the particular combination of conductor type/ voltages/ length and tension of a span*.

This obligation is listed in its Bushfire Mitigation Plan. The forecast is 113,227 spans. We consider the survey methodology to be sound. As the basis of this forecast is the result of a survey to establish a program to complete the works, documented in the Bushfire Mitigation Plan and subject to ongoing monitoring and reporting to Energy Safe Victoria, we accept this forecast.

The costs to be incurred for this activity are derived from actual contract rates used by Powercor. We have considered the unit rate. The unitised rate proposed by Powercor is derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. On this basis, we accept the Powercor unitised rate is efficient.

Accordingly, the resultant cost estimates reasonably reflect the capex criteria. For LBRA armour rods and vibration dampers we accept Powercor's forecast.

What are multi circuits?

When a power company erects a line of poles it may use the same poles to carry more than one circuit. A circuit is typically one set of three wires (or "phases"). Multi-circuits are powerlines with more than one set of three lines stacked on the same pole. On a multi-circuit line it is important that none of the wires can touch any other wire.

[263] Powercor, *Response to AER Information Request: Powercor - IR#030*, 4 September 2015 (Confidential).

LBRA Multi-circuit survey cost

To determine the volume of works to satisfy this obligation Powercor undertook a survey of its network using GIS data and a LIDAR survey.[264] We consider the survey methodology to be sound. This data was used to identify all spans with multi-circuits in Low Bushfire Risk Areas.

This obligation is listed in its Bushfire Mitigation Plan. The forecast is 550 kms. As the basis of this forecast is the result of a survey to establish a program to complete the works, documented in the Bushfire Mitigation Plan and subject to ongoing monitoring and reporting to Energy Safe Victoria, we accept this forecast.

The costs to be incurred for this activity are derived from actual contract rates used by Powercor for works conducted in the current regulatory control period. We have considered the unit rate. The unitised rate proposed by Powercor is derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. On this basis, we accept the Powercor unitised rate is efficient.

Accordingly, the resultant cost estimates reasonably reflect the capex criteria. For LBRA multi-circuit survey we accept Powercor's forecast.

LBRA Multi-circuit Repairs (Fitting of Spacers)

To determine the volume of works to satisfy this obligation Powercor undertook a survey of its network using GIS data and a LIDAR survey.[265] We consider the survey methodology to be sound. This data was used to identify all spans with multi-circuits in Low Bushfire Risk Areas.

This obligation is listed in its Bushfire Mitigation Plan. The forecast is 270 spans. As the basis of this forecast is the result of a survey to establish a program to complete the works, documented in the Bushfire Mitigation Plan and subject to ongoing monitoring and reporting to Energy Safe Victoria, we accept this forecast.

The costs to be incurred for this activity are derived from actual contract rates used by Powercor for works conducted in the current regulatory control period. We have considered the unit rate. The rate is significantly less than the rate allowed by the AER in 2011. The unitised rate proposed by Powercor is derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties

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[264] Powercor, *Regulatory Proposal 2016–20*, *PAL CONFIDENTIAL MOD 1.28 - PAL VBRC capex and contingent projects.xlsm.*

[265] Powercor, *Regulatory Proposal 2016–20, PAL CONFIDENTIAL MOD 1.28 - PAL VBRC capex and contingent projects.xlsm.*

which will arise as this program is completed. On this basis, we accept the Powercor unitised rate is efficient.

Accordingly, the resultant cost estimates reasonably reflect the capex criteria. For LBRA Multi-circuit Repairs (Fitting of Spacers) we accept Powercor's forecast.

HBRA Multi-circuit Rebuilds

This work is a consequence of the ESV direction to fit spacers. Powercor note that it is not possible to fit spacers to all spans of their network. This is known to be an issue with 66kV lines because no suitable spacer exists. Consequently, a small number of spans will require reconstruction to comply with the direction.

To determine the volume of works to satisfy this obligation Powercor undertook a survey of its network using GIS data and a LIDAR survey. This data was used to identify all spans with multi-circuits in both High and Low Bushfire Risk Areas. We consider the survey methodology to be sound. Only a proportion of the spans surveyed required treatment in the initial program. The treatment rate was 7.8%. This treatment rate has been applied to this forecast.[266]

This obligation is listed in its Bushfire Mitigation Plan. The forecast is 284 spans. As the basis of this forecast is the result of a survey to establish a program to complete the works, documented in the Bushfire Mitigation Plan and subject to ongoing monitoring and reporting to Energy Safe Victoria, we accept this forecast.

The costs to be incurred for this activity are derived from actual contract rates used by Powercor for works conducted in the current regulatory control period. We have considered the unit rate. The unitised rate proposed by Powercor is derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. On this basis, we accept the Powercor unitised rate is efficient.

Accordingly, the resultant cost estimates reasonably reflect the capex criteria. For HBRA Multi-circuit Rebuilds we accept Powercor's forecast.

LBRA Multi-circuit Rebuilds

This work is a consequence of the ESV direction to fit spacers. Powercor note that it is not possible to fit spacers to all spans of their network. This is known to be an issue with 66kV lines because no suitable spacer exists. Consequently, a small number of spans will require reconstruction to comply with the direction.

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[266] Powercor, *Regulatory Proposal 2016–20, PAL CONFIDENTIAL MOD 1.28 - PAL VBRC capex and contingent projects.xlsm*.

To determine the volume of works to satisfy this obligation Powercor undertook a survey of its network using GIS data and a LIDAR survey. This data was used to identify all spans with multi-circuits in both High and Low Bushfire Risk Areas. We consider the survey methodology to be sound. Only a proportion of the spans surveyed required treatment in the initial program. The treatment rate was 7.8%. This treatment rate has been applied to this forecast.[267]

This obligation is listed in its Bushfire Mitigation Plan. The forecast is 630 spans. As the basis of this forecast is the result of a survey to establish a program to complete the works, documented in the Bushfire Mitigation Plan and subject to ongoing monitoring and reporting to Energy Safe Victoria, we accept this forecast.

The costs to be incurred for this activity are derived from actual contract rates used by Powercor for works conducted in the current regulatory control period. We have considered the unit rate. The unitised rate proposed by Powercor is derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. On this basis, we accept the Powercor unitised rate is efficient.

Accordingly, the resultant cost estimates reasonably reflect the capex criteria. For LBRA Multi-circuit Rebuilds we accept Powercor's forecast.

What is Rapid Earth Fault Current Limiting (REFCL) Technology?

The Victorian Government is currently investigating technology solutions which reduce the cost of minimising the risk of a powerline fault igniting a fire. The REFCL is a relatively new technology which may have cost advantages. Its potential for bushfire mitigation is promising. It is an extension of resonant earth system technology, which is commonly used in Europe and elsewhere. The REFCL device is capable of detecting when a power line has fallen to the ground and can almost instantaneously shut off power on the fallen line.

REFCLs - detailed design

As noted above, two REFCLs are to be installed by Powercor at the Woodend and Gisborne substations as per the approved BMP. Because these installations are an existing regulatory obligation this work must be funded in this determination. We have considered the total design allowance sought for this program. We are satisfied that a significant portion of this cost will be incurred in relation to the trial installations. We consider the balance of these costs is relatively small. Further, the AER's requirement is for a detailed costing to be prepared for each contingent project before it is submitted to the AER. Although the balance of the design costs could be included in

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[267] Powercor, *Regulatory Proposal 2016–20, PAL CONFIDENTIAL MOD 1.28 - PAL VBRC capex and contingent projects.xlsm.*

the contingent project costings when they arise, we consider it is more efficient to determine these costs now.

Considerable uncertainty surrounds the amount of works necessary to add a REFCL device to a network. Detailed surveys must be undertaken and significant design effort expended to determine the necessary expenditure to safely add the device to the network. We consider Powercor's allowance for design costs is modest, given these demands. On this basis, we accept this forecast.

Accordingly, the resultant cost estimates are a reasonable estimate of the least cost necessary to satisfy the capex objectives. For REFCLs detailed design we accept Powercor's forecast.

REFCLs - Installation

As noted earlier, Powercor has an obligation in its BMP to undertake a trial of REFCL technology at its Woodend and Gisborne substations. This proposed capex is, therefore, required to maintain the reliability and safety of its network and to comply with applicable regulatory obligations or requirements. As the basis of this forecast is the obligation documented in the BMP and subject to ongoing monitoring and reporting to Energy Safe Victoria, we accept this forecast.

Installation of a REFCL requires significant investment in additional measures to prepare the network to operate safely with the device. This is because when a fault occurs the network is subjected to voltage stress that can damage other components if they are not rated to withstand the stress condition. Another requirement is to balance the capacitance of the network. This is a technical parameter. It can involve significant work to achieve this requirement. Powercor has prepared preliminary estimates of the costs it believes are necessary to undertake the trial installations.[268]

The unit costs contained in their project estimate are generally consistent with their reported costs for similar works elsewhere in their network. However, the estimated volumes do not align with the total project cost estimate. Also, a number of unit costs are not stated. The estimate also appears to be based on a superficial investigation of the proposed installations. The difference in costs is attributed to costs to balance the network and the trial nature of the installation. We have therefore considered whether there is an alternative approach to establishing an allowance for this project.

Our preference would be to rely on the Victorian Government Regulatory Impact Statement (RIS) to better inform this cost estimate. However, the RIS has not been released. We have considered the costs of an earlier trial of the technology. That trial incurred a cost of approximately $12 million. However, the trial incurred a number of unusual costs due to local failures of underground cables. We do not expect this will be repeated at Gisborne and Woodend. Once we adjust for these costs, we estimate a

[268] Powercor, *Regulatory Proposal 2016–20, PAL CONFIDENTIAL MOD 1.28 - PAL VBRC capex and contingent projects.xlsm*.

lower median cost, but subject to significant variability, depending on feeder configuration. As the Powercor project involves two installations, the total project cost falls within the expected range using this metric. On this basis, we have accepted the Powercor forecast. We note that for the contingent projects we will require significantly greater detail to be submitted to substantiate the project costs.

Accordingly, the resultant cost estimates are a reasonable estimate of the least cost necessary to satisfy the capex objectives. For REFCLs installation we accept Powercor's forecast.

What are Single Wire Earth Return (SWER) Automatic Circuit Reclosers (ACRs)?

SWER is a low-cost type of powerline construction most commonly used for small loads in rural and remote areas. Automatic circuit reclosers are a switch which operates when a brief fault occurs to temporarily interrupt supply. This requirement relates to fitting ACRs that can be remotely controlled on high fire risk days to isolate SWER powerlines should a fault occur.

VBRC Single Wire Earth Return (SWER) Automatic Circuit Reclosers (ACRs)

Powercor initially prepared its forecast for SWER ACRs based on consideration of its Geographical Information System (GIS) and augmented by a physical survey. This was documented in its Bushfire Mitigation Plan. The plan has progressed in the current period but the program is incomplete. The residual number of ACRs to be treated is 1,088.[269] We consider the survey methodology to be sound. As the basis of this forecast is the result of a survey to establish a program to complete the works, adjusted for works completed or programmed to be completed in the 2011–15 regulatory control period, we accept this forecast.

The costs to be incurred for this activity are derived from actual contract rates used by Powercor for works conducted in the current regulatory control period. We have considered the unit rate. The unitised rate proposed by Powercor is derived from contracts with independent service providers. We are satisfied the contracts were properly entered into on a competitive basis, based on a detailed work specification. The unitised rate is a market tested rate. The rate takes into account the terrain and access difficulties which will arise as this program is completed. On this basis, we accept the Powercor unitised rate is efficient.

Accordingly, the resultant cost estimates are a reasonable estimate of the least cost necessary to satisfy the capex objectives. For SWER ACRs installation we accept Powercor's forecast.

[269] Powercor, *Regulatory Proposal 2016–20, PAL CONFIDENTIAL MOD 1.28 - PAL VBRC capex and contingent projects.xlsm.*

Future regulatory obligations

Following the Victorian Bushfires Royal Commission (VBRC) 67 recommendations were made, of which eight relate directly to the safety of electrical distribution networks in Victoria. A relevant recommendation is recommendation 27:

> The State amend the Regulations under Victoria's Electricity Safety Act 1998 and otherwise take such steps as may be required to give effect to the following:
>
> - the progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk. The replacement program should be completed in the areas of highest bushfire risk within 10 years and should continue in areas of lower bushfire risk as the lines reach the end of their engineering lives
> - the progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives. Priority should be given to distribution feeders in the areas of highest bushfire risk.

The Victorian Government is developing a regulatory requirement to give effect to recommendation 27. In particular, work is being undertaken by the Victorian Government to develop suitable regulatory standards for the use of new technologies such as Rapid Earth Fault Current Limiting (REFCL) devices and a new type of insulated line as major tools to reduce the risk of powerline faults igniting bushfires.

These regulations are expected to apply in High Bushfire Risk Areas (HBRA) of the State and will involve a mandatory program of installing REFCLs and a change to the design standards that apply to new line construction and the reconstruction of assets in certain areas (Codified Areas). However, this Victorian Government program is not yet in place. The timing and scope of the regulations are not currently known.

Powercor has recognised this impending development in their regulatory proposal. They propose that the pending regulatory changes be dealt with as contingent projects.[270] However, AusNet Services proposed the AER apply a regulatory change pass through event to any regulatory change or changes that apply in the next regulatory control period.[271] We broadly agree that a contingent project or a pass through event can reasonably be applied to this program. We have therefore, considered whether either approach is preferable (contingent project or pass through event) and the trigger event which should apply for any contingent project.

Having considered the respective proposals of AusNet Services and Powercor, we consider a contingent project approach is preferable. Our preference is to apply a common regulatory approach to all affected service providers. We prefer to deal with

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[270] Powercor, *Regulatory Proposal 2016–20*, April 2015, p. 143.

[271] AusNet Services, *Regulatory Proposal 2016–20*, April 2015, p. 260.

the costs of the Victorian government regulations consistently across distributors. This ensures that the cost of the regulation is recovered from customers in the same manner. It also allows us to compare the costs and impacts on customers more transparently so that we can ensure that consumers pay no more than necessary for the implementation of the regulation. This is particularly important because the cost and timing of the regulation are not yet known.

We note that the contingent project mechanism was added to the NER to assist distribution networks faced with large but uncertain capital requirements to manage the risk of being required to fund major investments at short notice. We consider the potential impact of the planned Victorian regulations is an example of uncertain capital requirements that Powercor will face in the next regulatory control period.

Powercor contingent projects

REFCLs and Codified Areas

Powercor has proposed two contingent projects: REFCLs ($63 million) and Codified Areas ($235 million). REFCL technology is discussed above. The term "Codified Areas" is a shorthand reference to new regulations which are expected to require new, higher powerline construction standards to apply in high bushfire risk areas of the State. The regulations may specify that particular technologies or particular design standards must be used in high-consequence fire risk areas.

We accept that Powercor has based these proposals on the best available information. The volumes and unit rates that Powercor have used to prepare their proposals are consistent with current industry norms for similar works. However, until the regulations are in place it is not possible to determine with certainty either the number or location of the REFCLs to be deployed in the 2016–20 regulatory control period. Unit rates may also need to be updated. Similarly, the final scope of works cannot be determined for codified areas until the design standards are resolved, the areas to be treated specified and detailed design work undertaken.

To minimise the risk that the appropriate capital amounts may be difficult to accurately identify our preference is deal with the capital need progressively across the next regulatory control period. This can be achieved by dealing with the contingent project program in tranches. By doing so, both the service providers and the AER, as well as stakeholders, can better identify costs as they arise in the initial tranche of projects and apply corrections based on actual outcomes to the second and any subsequent tranches of projects. Each tranche must be sized to meet the applicable materiality threshold.

Although the Victorian Government may nominate that specific installations must be delivered by a particular date, this will not prevent the businesses from organising their programs into a different program. To achieve operational efficiencies the AER will allow projects to be swapped between tranches so long as this does not result in double counting for the purposes of assessing whether the trigger for a tranche has occurred.

Trigger event for REFCLs and Codified Areas

For a contingent project a trigger event must be defined. Powercor proposed that the trigger event for each of the two VBRC related contingent projects should be the occurrence of a regulatory event, being the introduction of a new regulatory obligation by the State of Victoria.[272]

We do not consider this is a sufficient trigger to satisfy clause 6.6A.1(b)(2)(ii) of the NER. Although the occurrence of this event will introduce new obligations on Powercor, it will not be apparent what the efficient costs to be incurred will be until other significant actions are completed. The costs can only be ascertained when the program of works has been defined in greater detail than is currently available. This requires the works be organised into a specific timetable. Also, the assets to be modified must be identified and design investigations undertaken before the works can be fully costed. For these reasons we reject Powercor's proposed trigger.

We consider there are three factors which, taken collectively, form the necessary conditions as a trigger event.

The first is a regulatory event. This is 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. This event will create a general obligation on Powercor to incur costs but it does not provide insight into the prudent and efficient costs that Powercor will face.

The second is the formation of capital projects into suitably sized tranches, having regard to the applicable materiality threshold. To ascertain the likely timing of capital requirements it is necessary to know the sequencing of projects. We will require that all the projects which constitute a tranche are listed in a regulatory instrument or a bushfire mitigation plan approved by Energy Safe Victoria for completion in the 2016–20 regulatory control period.

The third arm of our trigger event concerns identification of the efficient cost of the tranche. Every project incorporated in a tranche must be subject of a detailed design investigation which accurately identifies the scope of works and proposed costings when submitted to the AER.

We accept Powercor's proposal that two contingent project event categories be created to address capital needs arising from new regulations to be introduced by the Victorian Government to implement recommendation of the VBRC. These categories are:

1. The installation of equipment to achieve a new earth fault standard; and
2. The introduction of new design standards for asset construction and replacement in high consequence bushfire ignition areas of the State.

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[272] Powercor, *Regulatory Proposal 2016–20, Appendix L: Managing uncertainty*, April 2015, p. 5.

Each contingent project category is to contain one or more tranches. These contingent projects are each 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 2016–20 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.

There is considerable uncertainty as to the scope of works and hence, the costs which will be necessary to satisfy the Victorian Government program. By dividing the proposed contingent projects into tranches subject to detailed design and cost investigations we consider clause 6.6A.1(c)(5)(ii) will be satisfied. We note that the actual costs of a contingent project are determined when a trigger event has been satisfied.

On this basis, we have not sought to amend Powercor's suggested allowances of $63 million and $235 million respectively for REFCLs and Codified areas, which are to be included as contingent projects.

Powercor also proposed a third contingent project under the broad heading of future uncertainty, which we now consider.

Privately owned electric power lines

Powercor also proposed a contingent project event be defined for a change in responsibilities for Private Overhead Electric Lines (POELs).[273] The proposed trigger for this event is:[274]

> Changes to the Electricity Safety Act 1998 and/or Electricity Safety (Installations) Regulations 2009 that result in a change in Powercor's responsibilities for POELs.

We do not consider this project is reasonably required to be undertaken in order to achieve any of the capital expenditure objectives.[275] This is because this proposal is based on a requirement to meet a regulatory obligation which may not exist. Although there is a possibility that a regulatory obligation may exist in future, Powercor's proposal only cites options being considered by Energy Safe Victoria, which if adopted,

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273 Powercor, *Regulatory Proposal 2016–20, Appendix L: Managing uncertainty*, April 2015, p. 5.

274 Powercor, *Regulatory Proposal 2016–20, Appendix L, Managing uncertainty,* April 2015, p. 5.

275 NER, cl. 6.6A.1(b)(1).

would lead to a regulatory obligation.[276] The material before us does not demonstrate that it is probable that Energy Safe Victoria will adopt any of the options. Therefore, it remains speculative that a regulatory obligation will exist.

The capital expenditure objectives require that if a regulatory obligation does not exist that the expenditure must be necessary to maintain the quality, reliability and security of supply of standard control services; to maintain the reliability and security of the distribution system through the supply of standard control services; or, maintain the safety of the distribution system through the supply of standard control services.[277] The Powercor proposal does not address these alternative criteria for acceptance of an expenditure proposal.

We do not accept this project should be a contingent project. We also consider this proposed event would be eligible for examination as a pass through event under clause 6.6.1. An action by Victoria to amend the Law or Regulations would be likely to be considered as either a service standard event or as a regulatory change event under clause 6.6.1(a1). As we consider a pre-defined category of pass through event can apply, we do not consider a nominated pass through event should apply. Therefore, were the POELs event to arise, Powercor can seek to amend their determination through a pass through application under clause 6.6.1.

B.6 Forecast capitalised overheads

Capitalised overheads are costs associated with capital works that have been capitalised in accordance with Powercor's capitalisation policy. They are generally costs shared across different assets and cost centres.

B.6.1 Position

We do not accept do not accept Powercor's proposed capitalised overheads. We instead included in our alternative estimate of overall total capex an amount of $197.7 million ($2015) for capitalised overheads. This is 2.3 per cent lower than Powercor's proposal of $202.3 million ($2015). We are satisfied that this amount reasonably reflects the capex criteria.

B.6.2 Our assessment

We consider that reductions in Powercor's forecast expenditure should see some reduction in the size of its total overheads. Our assessment of Powercor's proposed direct capex demonstrates that a prudent and efficient DNSP would not undertake the full range of direct expenditure contained in Powercor's regulatory proposal. It follows that we would expect some reduction in the size of Powercor's capitalised overheads. We do accept that some of these costs are relatively fixed in the short term and so are

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276 Powercor, *Regulatory Proposal 2016–20, Appendix L: Managing uncertainty,* April 2015, pp. 50–55.

277 NER, cl. 6.5.7(3) & cl. 6.5.7 (4).

not correlated to the size of the expenditure program. However, we maintain that a portion of the overheads should vary in relation to the size of the expenditure.

Our assessment in the Queensland distribution determinations found Energex's overheads comprised 75 per cent fixed and 25 per cent variable components. We consider this split of fixed and variable overheads components is also reasonable for Powercor. If Powercor does not consider this split is reasonable for its circumstance, it may provide a more appropriate split, with evidence, in its revised regulatory proposal.

We have also considered the relationship between opex and capex, specifically whether it is necessary to account for the way the CAM allocates overheads between capex and opex in making this decision. We considered this was not necessary in order to satisfy the capex criteria. This is because our opex assessment sets the efficient level of opex inclusive of overheads. It has accounted for the efficient level of overheads required to deliver the opex program by applying techniques which utilise the best available data and information for opex.

The starting point of our capitalised overheads assessment is Powercor's proposal, which is based on their CAM. As such, Powercor's forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of Powercor's approved capex based on assessment techniques best suited to each of the capex drivers. In doing so we have accounted for there being a fixed proportion of capitalised overheads.

As a result of a $158.2 million ($2015) reduction in Powercor's direct capex that attract overheads, we consider a reduction of $4.6 million ($2015) reasonably reflect the capex criteria.

B.7 Forecast non-network capex

The non-network capex category for Powercor includes expenditure on information technology (IT), buildings and property, motor vehicles, and plant and equipment. Powercor proposed $262.1 million ($2015) for non-network capex, compared to actual expenditure of $190.6 million in the 2011–15 regulatory control period. It proposed $175.3 million for IT capex, compared to $104.9 million in the previous period. It has also proposed $86.8 million for the other non-network capex categories, compared to $85.7 million in the previous period. We have not accepted Powercor's proposal. Instead we have included an amount of $226.4 million, comprised of $139.6 million for IT capex and $86.8 million for other non-network capex.

B.7.1 Position

Powercor forecast total non-network capex of $262.1 million ($2015) for the 2016–20 regulatory control period.[278] We do not accept Powercor's proposal. We have instead included an amount of $226.4 million ($2015) for forecast non-network capex in our

[278] Powercor, Regulatory information notice, template 2.6, April 2015.

estimate of total capex which we consider reasonably reflects the capex criteria. This is a reduction of around 14 per cent.

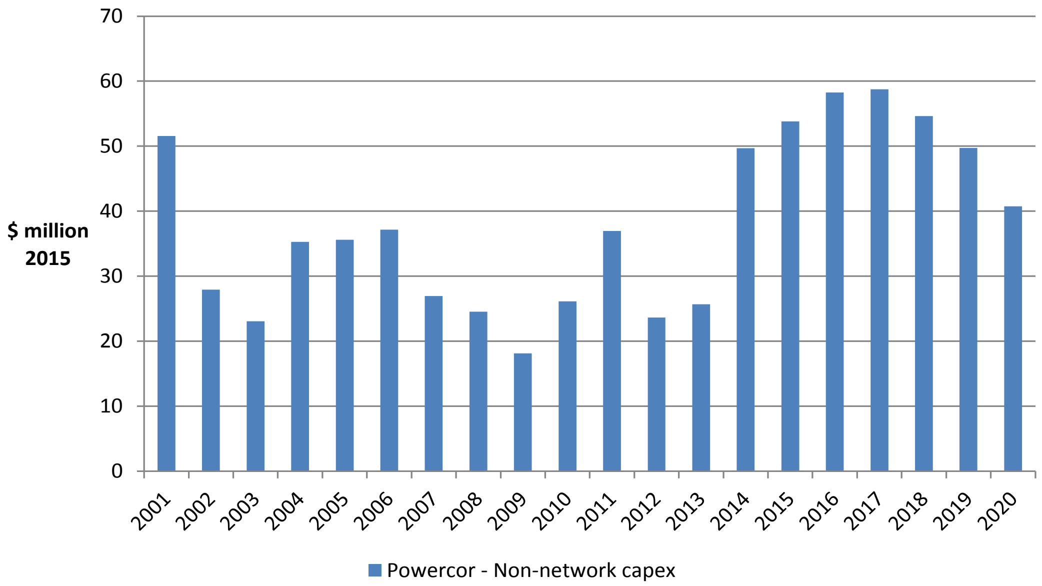
In coming to this view, we have found that Powercor's forecast non-network IT capex of $175.3 million does not appropriately reflect the efficient costs that a prudent operator would require to achieve the capex objectives. We consider that forecast capex of $139.6 million ($2015) reasonably reflects a prudent and efficient level of capex that is deliverable in the 2016–20 regulatory control period. This is a reduction of 20.4 per cent for this expenditure.

In modelling Powercor's required revenue for the 2016–20 regulatory control period, we have also accounted for forecast disposals of fleet assets which Powercor omitted from its regulatory proposal.

B.7.2 Powercor's proposal

Figure 6.19 shows Powercor's actual and expected non-network capex for the period from 2001 to 2015, and forecast capex for the 2016–20 regulatory control period.

Figure 6.19 Powercor's non-network capex 2000-01 to 2019-20 ($million, 2015)



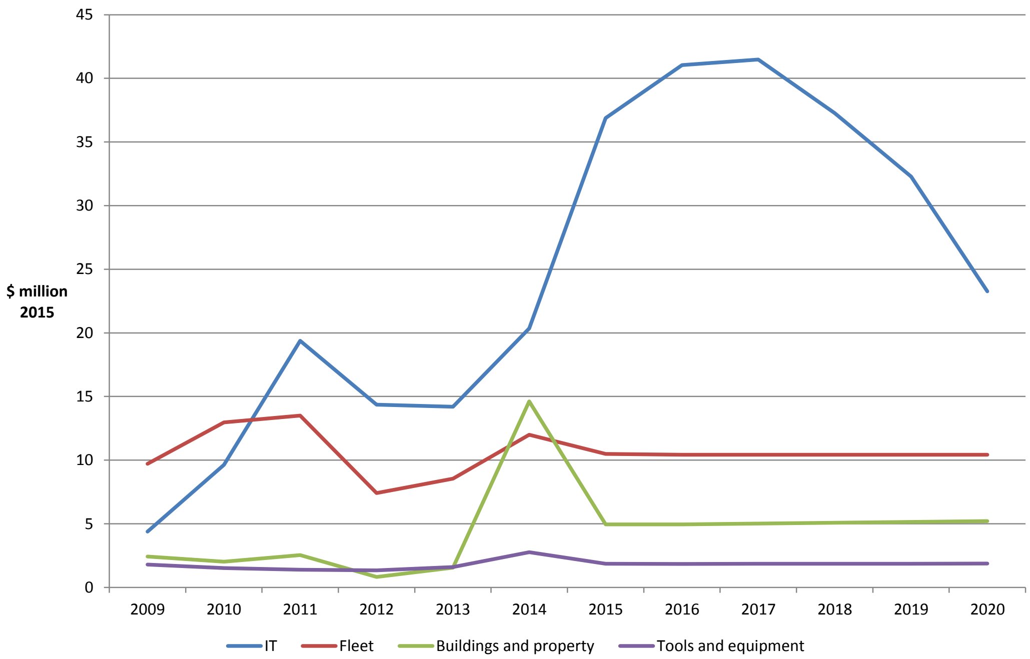
Source: Powercor, *Regulatory information notice*, template 2.6; Powercor, *Category Analysis RIN 2014*, template 2.6; Powercor, *RIN response for 2010-2015 regulatory control period, template 2.1.1*; AER analysis.

Powercor's forecast non-network capex for the 2016–20 regulatory control period is 38 per cent higher than actual and expected capex in the 2011–15 regulatory control period.

Our analysis of longer term trends in non-network capex suggests that Powercor has forecast capex for this category at historically high levels for most of the regulatory control period. Non-network capex in each of the first three years of the 2016–20 regulatory control period is forecast to be higher than expenditure in any year of the 2011–15 regulatory control period, and higher than any year since 2001. We therefore consider that Powercor's forecast non-network capex program warrants further review to confirm the need for and timing of the proposed expenditure.

We have assessed forecast expenditure in each category of non-network capex. Analysis at this level has been used to inform our view of whether forecast capex is reasonable relative to historical rates of expenditure in each category, and to identify trends in the different category forecasts which may warrant further review.[279] Figure 6.20 shows Powercor's actual and forecast non-network capex by sub-category for the period from 2009 to 2020.

Figure 6.20 Powercor’s non-network capex by category ($million, 2015)



Source: Powercor, *Regulatory information notice*, template 2.6; Powercor, *Category Analysis RIN 2014*, template 2.6; AER analysis.

Powercor has forecast an increase in IT capex in the 2016–20 regulatory control period of 67 per cent. Forecast expenditure in the other categories of non-network capex is in line with average historical levels of expenditure in these categories. On this basis, we accept that forecast capex for these minor non-network categories reflects the high level drivers of expenditure in these categories, and reasonably reflects the efficient costs of a prudent operator.

[279] NER, cl. 6.5.7(e)(5).

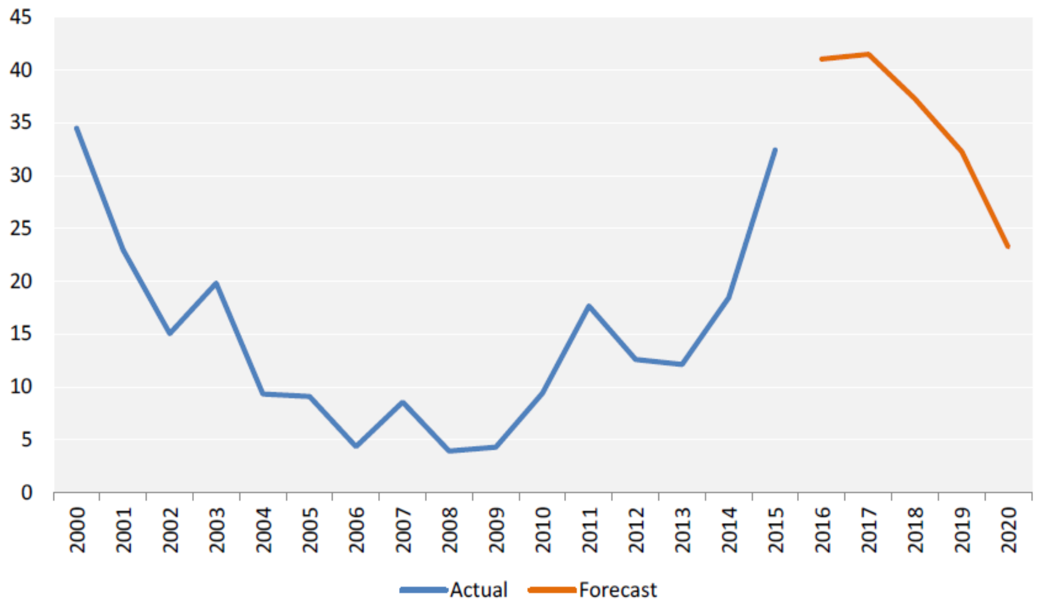
We undertook a detailed review of the justification for Powercor's forecast IT capex to confirm the need and timing of the forecast expenditure. Our conclusions are summarised below.

B.7.3 Information technology capex

Powercor has forecast non-network IT capex of $175.3 million ($2015) for the 2016–20 regulatory control period.[280] This is an increase of $70.4 million or 67 per cent from actual and estimated expenditure in the 2011–15 regulatory control period.

Powercor stated that its IT program is in a cyclical upswing for 2015–2017, followed by a period of consolidation in 2018–2020 with these changes caused by the combination of regulatory change, continued movement to a smarter network, expanded use of mobility devices, generational change in a number of its systems, increased usage and storage of data, and fundamental changes in its IT security requirements. This upswing and consolidation in Powercor's IT capex can be further shown in Figure 6.21.[281]

Figure 6.21 Powercor's non-network capital expenditure ($ million, 2015)



Source: Powercor, *2016–20 Price Reset Appendix E Capital Expenditure*, April 2015, p. 143.

Changes from historical expenditure

As highlighted above, Powercor has increased its forecast IT capex by two thirds compared the 2011–15 regulatory control period. The Consumer Challenge Panel noted that IT capex, across the Victorian businesses, in the 2011–15 regulatory control

280 Powercor, *Regulatory Proposal 2016–20*, April 2015, p. 101.

281 Powercor, *Regulatory Proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, pp. 142–143.

period was generally higher than IT capex for the 2006–2010 regulatory control period because of one off adjustments. It considers that the levels from the 2006–2010 period still have significance in setting the IT capex for the 2016–20 regulatory control period because the ‘one off’ adjustments in the current period do not need to be replicated going forward.[282] In conclusion, the Consumer Challenge Panel suggested that IT capex should be reduced from its current levels, to bring it 'back to reasonable levels' of the 2006-2010 period.[283]

While we have concerns about the proposed levels of IT capex, we accept that the appropriate level may well be higher than that of the 2006–2010 period due to changes in the operating environment for businesses, such as the introduction of smarter grids and additional regulatory obligations.

Origin Energy stated that it is concerned by the persistently high levels of IT capex compared to the period 2012–15 and suggested that proposed IT capex should be closely scrutinised.[284]

We have assessed Powercor's forecast IT capex using both trend analysis and individual business cases. In our trend analysis, we have compared the proposed expenditure to historic expenditure, and sought to understand the reasons for material differences in forecast expenditure. In doing so, we have considered the underlying drivers of expenditure, including the investment lifecycle stage the business is in and its particular IT needs. Where we have decided to review individual projects or programs, we have examined any business cases and other supporting documentation provided by the business to assess whether the expenditure reasonably reflects the capex criteria.

Powercor divided its expenditure into recurrent and non-recurrent expenditure. Recurrent expenditure is for replacement, upgrades and maintenance of existing functionality and systems. Non-recurrent expenditure is for new functionality or new (not replacement) systems that will be introduced.[285]

Powercor submitted that 73 per cent, or $128 million, of its forecast IT capex for the 2016–20 regulatory control period is recurrent. However, this is 22 per cent, or $23.1 million, more than Powercor's combined non-recurrent and recurrent IT capex for the 2011–15 regulatory control period. Given how Powercor has defined recurrent expenditure, it is not clear why the forecast recurrent IT capex is almost one quarter higher than the previous period's total IT capex. This increase may be driven in large part by upgrades to existing system.

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282 Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 57-58.

283 Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 58-59.

284 Origin Energy, *Re Submission to Victorian Electricity Distributors Regulatory Proposals*, 13 July 2015, p. 8.

285 Powercor, *Revenue Proposal 2016–20, Appendix E: Capital expenditure, April 2015,* p. 143.

Powercor's forecast IT capex program consists of more than 100 individual projects, including implementing new customer relationship management and billing systems, and a number of 'Smarter Grid' projects to optimise network management, introduce smart analytics, and allow for network innovation. The projects span Powercor's IT landscape and include a large number of interdependencies. Powercor has forecast the necessary labour to implement its IT forecast, and proposed more than half of the labour to come from external sources, additional to its internal IT staff.[286]

Based on our high level review, we cannot conclude that Powercor's IT capex program is prudent and efficient. We are concerned that the proposed program is a large scale, complex and interdependent program of works which impacts broadly across core IT systems. Therefore, we have sought to further assess the proposed program through individual project reviews, below.

Project review

Powercor divided its IT capex forecast into seven streams: compliance, currency and capacity, customer engagement, device replacement, infrastructure, security, and smarter networks.

These streams are divided into more than one hundred smaller projects, all of which are supported by documentation setting out estimated costs, options and justification for the preferred option.[287] Additionally, some of the larger projects are supported by specific project cost/benefit analyses.

The Consumer Challenge Panel submitted that new IT systems should only be implemented when there is a clear benefit to consumers and that the benefits are integrated into the capex and opex forecasts.[288] The Victorian Energy Consumer and User Alliance noted that for a number of businesses, the capex programs were poorly justified with inadequate provision of cost benefit analyses and insufficient justification of prioritisation and timing of projects. They also stated a concern that businesses placed an overreliance on bottom up forecasting; therefore inadequately taking into account interrelationships between projects.[289] We have reviewed the documentation and further clarification submitted by Powercor in support of its proposed IT capex projects, to assess whether the forecast capex reflects the efficient costs that a prudent operator would incur.[290]

Four major projects that Powercor has proposed for the 2016–20 regulatory control period make up about 60 per cent of its IT capex forecast:

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286 Powercor, *Revenue Proposal 2016–20, CP PUBLIC APP E Capital expenditure,* pp. 146.

287 Powercor, *Response to AER Information Request AER CitiPower 013*, 24 July 2015. CitiPower, *Response to AER Information Request AER CitiPower 021*, 12 August 2015.

288 Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 56 and 59.

289 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 19.

290 NER, cll 6.5.7(c)(1) and 6.5.7(c)(2).

1. a new customer relationship management and billing system
2. a program to deliver a 'Smarter Grid
3. expenditure to meet RIN requirements, and
4. a program of IT security improvements.

Of these projects, only the documentation for the new billing system and the 'Smarter Grid' project show that the projects provide an economic return (positive NPV). The business case for the 'Smarter Grid' project shows that the sub projects each provide an economic return individually and as a total package.

The Consumer Challenge Panel's submission on Powercor's new billing system focused on the fact that Powercor did not include the associated consumer benefits in its opex and capex forecasts.[291] The Victorian Government supported Powercor's expenditure on a new customer relationship management system and web portal to allow consumers to obtain information from the businesses because these businesses are the only Victorian DNSPs that do not currently have an online customer portal.[292]

We accept that this expenditure reasonably reflects the criteria. While we agree with the Consumer Challenge Panel that there will be associated benefits through reduction in opex and capex, we find it reasonable that such benefits may not emerge within this regulatory control period. We also support the prudence and efficiency of the costs to provide this new system and have included an allowance for such a system in our forecast.

The 'Smarter Grid' project, as noted above, provides a positive economic return, both as a total package and as individual sub projects. We are satisfied that this project reflects the efficient costs that a prudent operator would incur to achieve the capex objectives. Therefore, we have included an allowance for this project in our forecast.

The documentation for the expenditure to meet RIN requirements and for IT security do not show whether or not these projects provide an economic return, in that they disclose the costs, but not the economic benefits of these projects. An economic justification is not the sole basis for proceeding with a capex project that may be otherwise necessary to meet the capex objectives of the NER.[293] For example, a particular capability may be necessary to comply with a regulatory obligation or to maintain the quality, reliability and security of supply. However, we must be satisfied that the forecast capex reasonably reflects the efficient costs that a prudent operator

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[291] Consumer Challenge Panel, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 56-57, 59, citing Deloitte Access Economics on behalf of CitiPower and Powercor, *Investing in a new billing and customer relationship management system*, 16 December 2014.

[292] Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 4.

[293] NER, cl. 6.5.7(a).

would require to achieve the capex objectives.[294] Based on our review, the evidence provided by Powercor for these two projects does not support this conclusion.

Specifically, we have concerns about the magnitude of expenditure proposed for each of the projects. The expenditure to meet RIN requirements is supported by a business case that estimates the costs of the project for CitiPower and Powercor, combined, at $28.6 million.[295] United Energy and SA Power Networks have also proposed IT capex for compliance with the RINs. However, AusNet Services, Jemena, Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, Energex and Ergon Energy have either not proposed any IT capex for this or only proposed very small amounts.

While we understand that IT capability may be different across different businesses, we would expect that the costs associated with RIN obligations would be relatively consistent across businesses. Further we sought information from network service providers on the cost of compliance when we were consulting on RIN obligations, but were not provided with any estimates.[296] Absent this information when establishing the requirements, we would find it reasonable to assume that the cost would not be material.

We recognise that each business is starting from a different position regarding its existing systems and data availability. Powercor stated that the category analysis RIN and the economic benchmarking RIN impose new requirements on it, which, to date, it has complied with by collecting information from outside existing systems and making estimates. However, the obligations on businesses going forward to provide actuals will require Powercor to reprogram its systems for RIN compliance.[297] Powercor's preferred option involved developing an automated approach to RIN compliance.[298] While we accept that Powercor may incur costs above those forecast by other companies in complying with RIN obligations, the amounts set out by Powercor are of a sufficient magnitude that we are not satisfied that they reflect prudent and efficient expenditure. As such and in the absence of further information, we do not accept the forecast of $20.2 million in this preliminary decision.

Powercor has proposed $10.5 million for IT security projects. We accept the need to ensure that Powercor's IT network is secure and is able to detect and address any security threats. However, Powercor has not provided information to quantify the cost of the risk it is attempting to address, or provided a cost benefit or options analysis. As such, our preliminary decision does not include the full forecast amount of $10.5 million.

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294 NER, cl. 6.5.7(c).

295 KPMG on behalf of CitiPower and Powercor, *Business Case for expenditure to meet RIN requirements*, April 2015, p. 7. CitiPower's proposed expenditure is 30 per cent of the total or $8.6 million.

296 AER, *Better Regulation: Explanatory Statement: Final regulatory information notices to collect information for category analysis*, March 2014, pp. 1-2, 8. AER, *Better Regulation: Explanatory Statement: Regulatory information notices to collect information for economic benchmarking*, November 2013, p. 9.

297 Powercor, *Revenue Proposal, PAL PUBLIC APP E Capital Expenditure*, pp. 158-159.

298 KPMG on behalf of CitiPower and Powercor, *Business Case for expenditure to meet RIN requirements*, April 2015, p. 12.

The remaining 40 per cent of Powercor's forecast IT capex is spread across multiple small projects across the compliance, currency and capacity, customer engagement, device replacement, infrastructure IT streams. The documentation Powercor provided for these projects did not include numerical cost benefit analyses, but did include costings and qualitative benefits. Some of the projects are to upgrade existing systems to the currently available version, and will ensure that Powercor's systems are not vulnerable due to out of support applications.[299] In these cases, we are satisfied that these are the efficient costs of a prudent operator based on the documentation of costings and systems requirement provided by Powercor.

Other projects in the compliance stream are to make changes to systems due to potential, but not yet defined, regulatory change. In the absence of information on the scope and costs of potential regulation, we are not satisfied that these reflect the efficient costs of a prudent operator required to achieve the capex objectives. If there are regulatory changes during the upcoming regulatory control period that are not currently defined, Powercor may make a cost pass through application to us for any material change in costs as these would likely be regulatory change events.[300]

Conclusion on information technology

Based on our review of both the total portfolio and individual projects, we are not sufficiently satisfied that Powercor's non-network IT capex forecast reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.[301] In determining our alternative estimate of non-network IT capex, we have considered the level of investment that is likely to be:

- prudent, having regard to Powercor's business needs in the 2016–20 regulatory control period
- efficient and justifiable, having regard to the economic evaluation of alternative investment options.

For this preliminary decision, we consider that non-network IT capex of $139.6 million ($2015) reasonably reflects Powercor's required capex for this category in the 2016–20 regulatory control period. This is a reduction of $35.7 million or 20.4 per cent compared to Powercor's forecast non-network IT capex. We derived our estimate by removing the expenditure for RIN compliance and making proportional reductions: for projects that have not been sufficiently justified, for projects that are speculative and therefore cannot be accurately costed, and for projects where some of the expenditure is not justified. Those reductions total to 10 per cent of the expenditure remaining after the removal of the RIN compliance project. Our estimate provides for a 33 per cent increase from actual non-network IT capex in the 2011–15 regulatory control period.

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299 These projects include projects in the currency and capacity, customer engagement, device replacement, and infrastructure IT streams.

300 NER, cl. 6.6.1.

301 NER, cl. 6.5.7(c).

In determining our alternative estimate of non-network IT capex, we examined the overall trend in IT capex as well as individual projects to arrive at a forecast of capex that is based on efficient costs. It is now up to Powercor to determine how best to allocate this budget throughout the 2016–20 regulatory control period. We are satisfied that the forecast capex of $139.6 million ($2015) reasonably reflects the efficient costs that a prudent operator would require to the capex criteria.[302] We will make an allowance for it in our estimate of total capex for the 2016–20 regulatory control period.

B.7.4 Fleet asset disposals

Powercor did not account for any disposals of fleet assets in its regulatory proposal. In assessing Powercor's forecast non-network capex, we sought further information regarding Powercor's forecast disposals of fleet assets in the 2016–20 regulatory control period.[303]

In response to our information request, Powercor advised that it expected proceeds from the sale of fleet assets over the 2016–20 regulatory control period of $10.4 million ($2015).[304] We have accounted for these disposals in modelling Powercor's required revenue for the 2016–20 regulatory control period.

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[302] NER, cll. 6.5.7(c)(1) and 6.5.7(c)(2).

[303] AER, *Information request Powercor IR# 005*, 23 June 2015.

[304] Powercor, *Response to information request Powercor IR# 005*, 30 June 2015.

C Maximum demand forecasts

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure.[305] This is because we must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of demand forecasts. Hence accurate, or at least unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network.

This attachment sets out our decision on Powercor's forecast network maximum demand for the 2016–20 regulatory control period. We consider Powercor's demand forecasts at the total system level and the more local level.

System demand represents total demand in the Powercor distribution network. System demand trends give a high level indication of the need for expenditure on the network to meet changes in demand. Forecasts of increasing system demand generally signal an increased network utilisation which may, once any spare capacity in the network is used up, lead to a requirement for growth capex. Conversely forecasts of stagnant or falling system demand will generally signal falling network utilisation, a more limited requirement for growth capex, and the potential for the network to be rationalised in some locations.

Localised demand growth (spatial demand) drives the requirement for specific growth projects or programs. Spatial demand growth is not uniform across the entire network: for example, future demand trends would differ between established suburbs and new residential developments.

In our consideration of Powercor's demand forecasts, we have had regard to:

- Powercor's proposal
- independent maximum demand forecasts from AEMO[306]
- a report by our internal economic consultant, Dr Darryl Biggar, on the forecasting methodologies underlying each Victorian electricity distributor's demand forecasts for 2016–20 (this report will be published alongside this preliminary decision)[307]
- long term demand trends and changes in the electricity market, and
- stakeholder submissions in response to Powercor's proposal (as well as submissions made in relation to the Victorian electricity distribution determinations more generally).[308]

These are set out in more detail in the remainder of this appendix.

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305 NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).

306 AEMO, *Transmission Connection Point Forecasting Report — For Victoria*, September 2014.

307 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015.

308 See AER, http://www.aer.gov.au/node/24446.

C.1 AER determination

We are not satisfied that Powercor's demand forecasts reasonably reflect a realistic expectation of demand over the 2016–20 regulatory control period. In determining a realistic expectation of demand over the 2016–20 period, we have had regard to the following factors:

- Changes observed in the electricity market and the way energy is consumed in recent years (e.g. strong uptake of solar PV, changing customer behaviours and energy efficiency measures) suggests that the strong positive demand growth seen in Powercor's network prior to 2009 is unlikely to return in the short to medium term. This is discussed in section C.3.
- Powercor's forecasting methodology effectively assumes that there is a fixed underlying relationship between demand and certain identified demand drivers (e.g. weather) and that this relationship has been correctly estimated in their model, using the past ten years of historic data, and that this relationship will continue to hold into the future. We are not satisfied that this reflects a realistic expectation of future demand over the 2016–20 period since we are not confident that the drivers used in Powercor's model are able to fully capture the changes in demand in recent years. This is discussed in section C.2 and C.4.
- Independent forecasts from AEMO better explain the actual demand pattern seen on all distributors' networks. This is because it does not assume a fixed structural relationship between demand and demand drivers over a long period and, instead, places greater reliance on industry knowledge and judgement. While not without its limitations, we consider that AEMO's forecasts better reflect recent changes in the electricity market. This is also discussed in section C.4.

We understand that Powercor (and the Victorian electricity businesses) are in the process of updating their demand forecasts as part of the 2015 distribution annual planning report (DAPR). We also note that AEMO will publish updated connection point demand forecasts for Victoria. We are open to Powercor submitting an updated demand forecast that account for the factors listed above, including the most recent demand data and AEMO's updated forecasts.

We consider the forecasts in our decisions should reflect the most current expectations of the forecast period. Hence, we will also consider updated demand forecasts and other information (such as AEMO's revised connection point forecasts) in the final decision to reflect the most up to date data.

We have also received a number of consumer submissions that raise concerns with Powercor's and the other Victorian distributors maximum demand forecasts. The CCP submitted that we should pay particular attention to the distributors maximum demand forecasts and whether they have been over estimated, given the following considerations:

- forecasts of maximum demand are key drivers of revenue requirements
- distributors' forecasts exceed and contrast with AEMO's forecasts, and

- distributors have consistently over forecast maximum demands in the past.[309]

The Ethnic Communities Council of Victoria (ECCV) also supported us further examining the Victorian distributors' forecasts that exceed forecasts by AEMO.[310]

The VECUA also submitted that the Victorian distributors have consistently over estimated their peak demand and energy delivered projections. VECUA put forward that network distributors are insulated from volume risk through revenue cap regulation, which allows them to pass that risk on to customers. Therefore if the actual energy delivered is lower than forecast by networks' then networks will increase their prices to recover their guaranteed revenues. VECUA also considered it important to note:[311]

> …that the Victoria distributors were rewarded with windfall profits for their forecasting errors, as their revenue allowances included returns and depreciation on load-driven capex which they did not incur.

As set out in this appendix, we have closely examined Powercor's maximum demand forecasts and drawn similar observations to these submissions. A key part of our work has been to analyse Powercor (and the other Victorian distributors) demand forecasts with reference to AEMO's independent maximum demand forecasts. However, the VECUA submitted that AEMO has consistently over estimated its energy forecasts in recent years and has not fully considered the influence of future factors in reducing demand (such as energy efficiency schemes, automotive closures, cost reflective price structures and battery storage technology).[312] We do not agree with the VECUA and consider that AEMO's explanation of its forecasting methodology reveals that it has considered a wide variety of information in its forecast, including predictions for energy efficiency and automotive closures in Victoria and this represents an enhancement and improvement to its previous forecast approach.[313]

Further, the CCP and VECUA referred to AusNet Services demand forecasts as the only Victorian distributor to forecast lower energy consumption in the future compared to the past.[314] VECUA has submitted that AusNet Services demand forecasting methodology incorporates actual interval metering data, which it considers may account for the differences between AusNet Services forecast growth and other

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309 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers, August 2015*, pp. 32-37.

310 Ethnic Community Council of Victoria, *Submission to the Australian Energy Regulator Victoria Electricity Pricing Review*, 15 July 2015, p. 4.

311 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, pp. 14-16.

312 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 17.

313 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 11.

314 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers, August 2015*, pp. 35-37; Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, pp. 15-16.

Victorian distributors.[315] The CCP considered that the AusNet Services approach to developing its forecast demand is a significant enhancement in forecasting future demand and is a direct outcome from the decision to mandate the roll out of the AMI program in Victoria.[316] We consider there is merit to these views (and will be useful as distributors develop their information capacity). However we have not directly taken this into account for our assessment of Powercor's maximum demand forecasts because it has not been necessary due our assessment approach which is based substantially on comparison with AEMO's demand forecasts.

C.2 Powercor's proposal

Powercor provided historical and forecast demand figures in their proposal and in the reset Regulatory Information Notice (RIN).[317] Powercor proposed approximately 3.4 per cent annual growth in maximum demand across the 2016–20 period. In its proposal, Powercor forecast an increase in peak demand in specific areas of its network to be driven by:

- 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.[318]

Powercor submitted that its forecast of peak demand growth is based on public information from the Victorian Government, the City of Greater Geelong and the Mildura Development Corporation.[319]

Powercor's engaged the Centre for International Economics (CIE) to develop its demand forecasts.[320] Powercor's proposal also included a brief summary of CIE's demand forecasting method, including approaches to:

- demand drivers
- accounting for economic conditions such as incomes and electricity prices
- projections of customer numbers by tariff class
- and post model adjustments for block loads and embedded generation.[321]

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315 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals*, 13 July 2015, p. 16.

316 CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp. 35–37 and p. 44.

317 Powercor reset RIN; Powercor, *Regulatory Proposal 2016–20,* April 2015, pp. 87, 92.

318 Powercor, *Regulatory Proposal 2016–20, April 2015,* p. 88.

319 Powercor, *Regulatory Proposal 2016–20, April 2015,* pp. 88–89.

320 Powercor, *Regulatory Proposal 2016–20,* April 2015, p. 96.

321 Powercor, *Regulatory Proposal 2016–20,* April 2015, p. 96.

Powercor's forecasting methodology is described in detail in Dr Biggar's report.[322]

C.3 Demand trends

Our first step in examining Powercor's forecast of maximum demand is to look at whether the forecast is consistent with, or explained by, long term demand trends and changes in the electricity markets.

Figure 6.22 shows that over the last few years the path of electricity demand seems to be changing. From 2006 to 2009, actual maximum demand on Powercor's network was growing steadily. Then from 2009 to 2012, demand flattened and declined. The decline in 2009 from historical demand growth has also been recorded for Victoria (as shown in Figure 6.23) and for the NEM. While there was some growth in demand between 2013 and 2014, this does not necessarily indicate a return to longer term growth in demand.

As shown further in Figure 6.22, Powercor's demand forecasts for the 2015–20 period are considerably higher than the actual demand observed for its network during 2006–14 (substantially so for its 10 PoE forecasts). Powercor forecasts a return to demand growth on the network similar to that experienced prior to 2009. This contrasts with AEMO's Connection Point Forecasts, published in September 2014, which forecasts little or no growth in connection point demand on Powercor's network for this period.[323]

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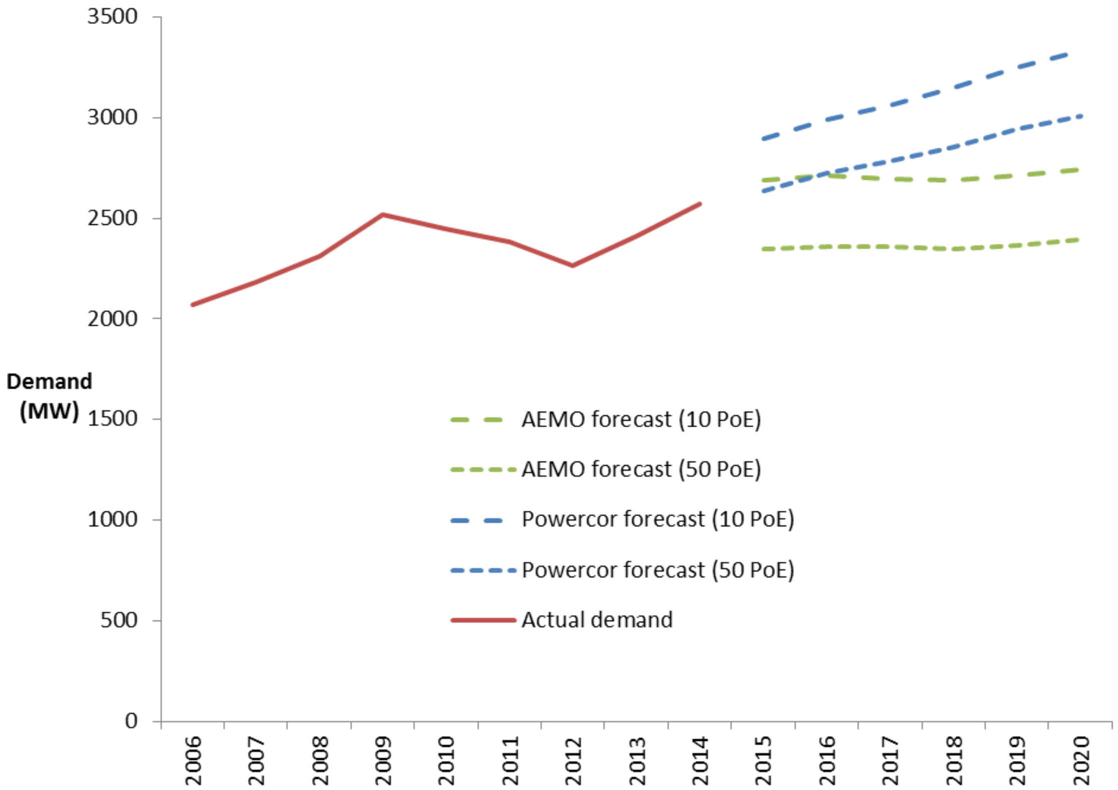
[322] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 21-22.

[323] AEMO, *Transmission Connection Point Forecasting Report for Victoria*, September 2014, pp. 12-13.

Figure 6.22 Comparison of maximum demand forecasts of Powercor and AEMO (MW, non-coincident, summated connection point forecasts)

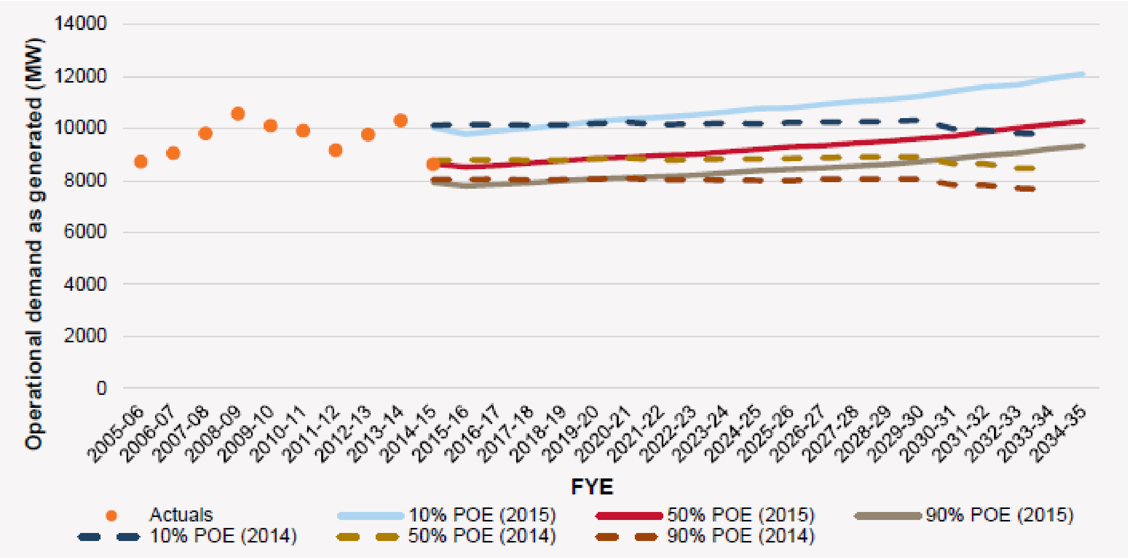


Source: Powercor regulatory proposal, AER analysis using AEMO data on transmission connection point forecasts; reset RIN; economic benchmarking RIN 2006–14.

Note: Actual demand over the 2006 to 2014 period reflects Powercor's actual maximum demand over this period (as reported in Powercor's economic benchmarking RIN data from 2006 to 2014). This is opposed to weather normalised historical maximum demand data.

Figure 6.23 shows AEMO's forecasts of maximum demand across Victoria. In its 2015 national electricity forecasting report, AEMO forecast a flattening of maximum demand for Victoria for 2015–2020. However, AEMO has forecast some growth in maximum demand over the next twenty years, which is a change from its 2014 national electricity forecasting report.

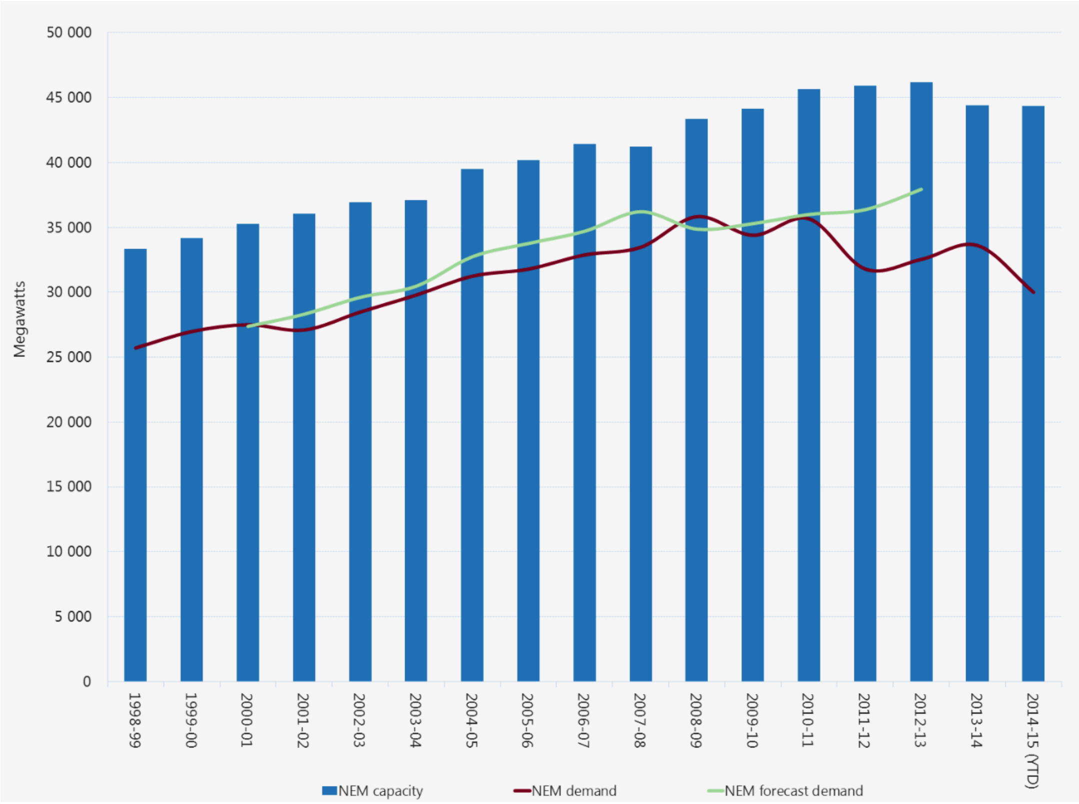
Figure 6.23 AEMO's maximum demand forecasts for Victoria



Source: AEMO, *2015 National Electricity Forecasting Report,* June 2015.

We see a similar change in peak demand patterns across the National Electricity Market (NEM). Figure 6.24 compares NEM peak demand together with the forecast peak demand two years ahead and total generation capacity, since the NEM began. It shows actual demand has been declining generally since 2008–09 across the NEM.

Figure 6.24 Comparison of historical generation capacity and peak demand across the NEM



Source: AER, accessed on 18 August 2015 at: https://www.aer.gov.au/node/9772.

Note: The step up in maximum demand in 2004–05 is as a result of Tasmania's entry to the NEM.

Powercor forecast strong demand growth for 2015–20, whereas other independent forecasts from AEMO predict low or no growth over this period. While actual connection point demand increased on Powercor's network in 2013 and 2014 (see Figure 6.22), the observed changes in demand patterns within the span of nine years raises the question of whether the recent flattening of demand is an aberration (and demand will return to growth) or a realistic expectation of demand over the 2016–20 period.

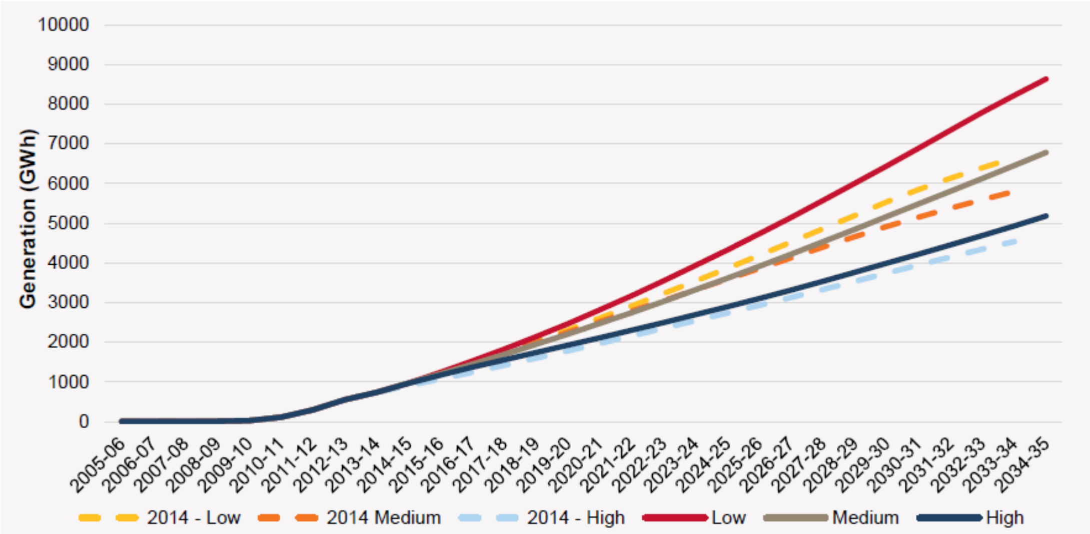
There have been some developments in the Australian and Victorian electricity markets over recent years that have influenced energy consumption and maximum demand patterns.

First, across the NEM, growth in rooftop solar generation (photovoltaics, or PV) and energy efficiency (through the uptake of energy efficient appliances and building efficiency) has reduced electricity drawn from the grid. Rooftop PV generation has had the long term effect of reducing maximum demand and shifting the daily peak to later in the evening. Energy efficiency reduced overall energy consumption and has a downward impact on maximum demand.

In Victoria, AEMO reported that in the five years to 2014–15, consumption in the residential and commercial sector decreased due to rising prices and the uptake of rooftop PV.[324] AEMO forecasts that there will be continued uptake of rooftop PV in the residential and commercial sectors.

To demonstrate, Figure 6.25 below, drawn from AEMO's 2015 national electricity forecasting report for Victoria, shows the projected capacity of solar PV systems across Victoria. From this figure we observe a projected increase in the volume of installed rooftop solar PV capacity can be observed from 2010 to 2015, with capacity expected to continue to grow in line with current levels of growth.[325]

Figure 6.25 Projected capacity of solar PV systems in Victoria



Source: AEMO, *2015 National Electricity Forecasting Report*, June 2015.

However, we note that the impact of rooftop PV will likely have diminishing impacts on maximum demand over the longer term as peak daily demand shifts to the evening. This is recognised in AEMO's forecasting report.[326] We note that electricity storage (e.g. batteries) has the potential to significantly enhance the impact of solar generation on maximum demand on the distribution network. However, wide spread uptake of battery storage will probably not be significant over the 2016–20 period.

Second, Energy efficiency also contributed to decreased consumption and AEMO forecasts that energy efficiency measures will continue.[327] Ongoing energy efficiency

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324 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report,* June 2015, p. 68.

325 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report,* June 2015, p. 73.

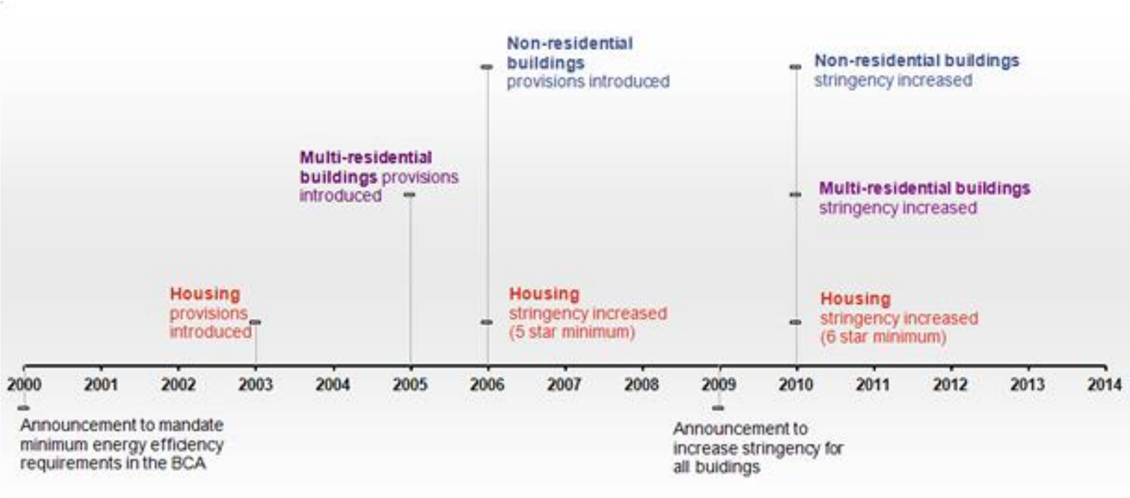
326 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 77.

327 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 67.

measures such as mandatory energy efficiency building requirements[328] and other government incentives[329] have created an accumulative effect in slowing down demand growth over time. In addition, greater customer awareness of energy usage, improving appliance efficiencies and replacement of aging appliances will likely continue to put downwards pressure on consumption and maximum demand.[330]

Figure 6.26 gives an overview of government energy efficiency requirements in building provisions. From this timeline it can be inferred that the increasing energy efficiency requirements in building regulation are likely to have a cumulative effect on demand in the future.

Figure 6.26 Timeline of Energy Efficiency Requirements in Building Regulation



Source: Australian Building Codes Board (ABCB), accessed on 27 August 2015 at: http://www.abcb.gov.au/en/work-program/energy-efficiency.aspx.

Third, the decline in the manufacturing sector and major industrial closures, many of which were not previously forecast, saw large decreases in industrial consumption in Victoria, with associated impacts on both consumption and maximum demand.[331] AEMO forecast that the decline in industrial consumption will continue in the short term, due to the planned closure of vehicle manufacturing plants.[332] However, this may

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328 Australian Building Codes Board (ABCB), *National Construction Code energy efficiency requirements*, http://www.abcb.gov.au/en/work-program/energy-efficiency.aspx , accessed on 27 August 2015.

329 Department of Industry and Science, *Your energy savings: Rebates*, http://yourenergysavings.gov.au/rebates?live_in%5B%5D=64&interested%5B%5D=82&=Search, accessed on 27 August 2015.

330 AEMO, *2015 National Electricity Forecasting Report: Overview*, June 2015, pp. 8-11.

331 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 68.

332 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report,* June 2015, p. 67.

be offset by growth in the residential sector, which is mainly driven by population growth.

The AEMC similarly notes that one of the drivers of the recent decline in electricity consumption is the reduction in large industrial loads, such as aluminium smelters, due to the structural shift in the Australian economy away from energy intensive industries. They go on to observe:[333]

> A recent step-change in energy consumption has occurred in the NEM with the closure of major industrial electricity users. Between October 2011 and September 2012, the Port Kembla steelworks, the Kurri Kurri aluminium smelter and the Clyde oil refinery were partially or completely shut down. This removed around 3,600 GWh of annual electricity consumption from the NEM. More recent closures include the Point Henry smelter and the Kurnell oil refinery, which both ceased operations in 2014.

Finally, AEMO also forecast that Victoria is not expected to recover to its historical high level of operational consumption (in 2008–09) until 2030–31, when population is projected to be 1.7 million higher than in 2014–15.[334]

We consider that the combination of these factors support forecast reductions or softening of maximum demand even in the presence of continued economic and population growth. In particular, based on our assessment of independent forecasts from AEMO, we consider the continuing presence of energy efficiency measures, improving appliance efficiencies and continued growth in rooftop PV will likely put downward pressure on demand, which may counteract any demand growth due to economic and population growth. Solar PV and energy efficiency are not transient or temporary phenomena, but rather changes in the way electricity is consumed.

As set out in section C.4 below, we consider that Powercor's forecasting methodology does not adequately capture the changes we are observing for the electricity market in Victoria and recent declines in demand. This is because Powercor's methodology assumes that their modelled historical relationship between demand and demand drivers will continue to hold over the 2016–20 period. We are not satisfied that this reflects a realistic expectation of future demand over the 2016–20 period since we are not confident that the drivers used in Powercor's model are able to fully capture the changes in demand in recent years.

We recognise that demand trends will not be identical in all regions of Victoria, and that some areas will exhibit higher demand growth than others. For example, Powercor is forecasting significant demand growth in some parts of its network (e.g. Western Melbourne growth area) which is driven by high forecast population growth. As shown in Table 6.23 below, this is reflected in higher forecast demand growth in both Powercor's and AEMO's forecasts when compared to the other Victorian distributors.

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333 AEMC, *2014 electricity price trends report*, 5 December 2014, p. 18.

334 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 67.

Table 6.23 Forecast growth in peak demand 2016–20 — AEMO and Victorian DNSPs

Distributor	Regulatory Proposal Forecasts	AEMO forecast
AusNet Services	1.07%	–0.09%
CitiPower	2.38%	0.40%
Jemena	1.46%	–0.10%
Powercor	3.54%	0.27%
United Energy	2.05%	0.14%

Source: Regulatory proposals, AER analysis using AEMO data on transmission connection point forecasts.

However, it is important to recognise that economic factors such as population growth are also taken into account in AEMO's independent forecasts. At the same time, major industrial closures are expected in Powercor's network over the coming period.[335] In addition, factors such as the recent smart meter rollout,[336] developments in energy efficiency (as discussed above), and the increasing viability of battery technology and the expected new tariff structures[337] will likely further moderate maximum demand in the next regulatory control period. Therefore, while Powercor's forecasts may reflect the impact on forecast population growth, this does not necessarily outweigh the impact of other factors that are contributing to reduced maximum demand across Victoria and the NEM.

We note this is consistent with international trends. Figure 6.27 highlights the fact that growth in electricity demand is currently low or zero in the USA and UK despite the existence of continued population growth and economic growth. In other words, this chart suggests that the impact of economic growth and population growth on electricity demand is being offset by other factors (such as improving energy efficiency). On this basis, it is reasonable to argue that high growth is unlikely to return over 2016–20.[338]

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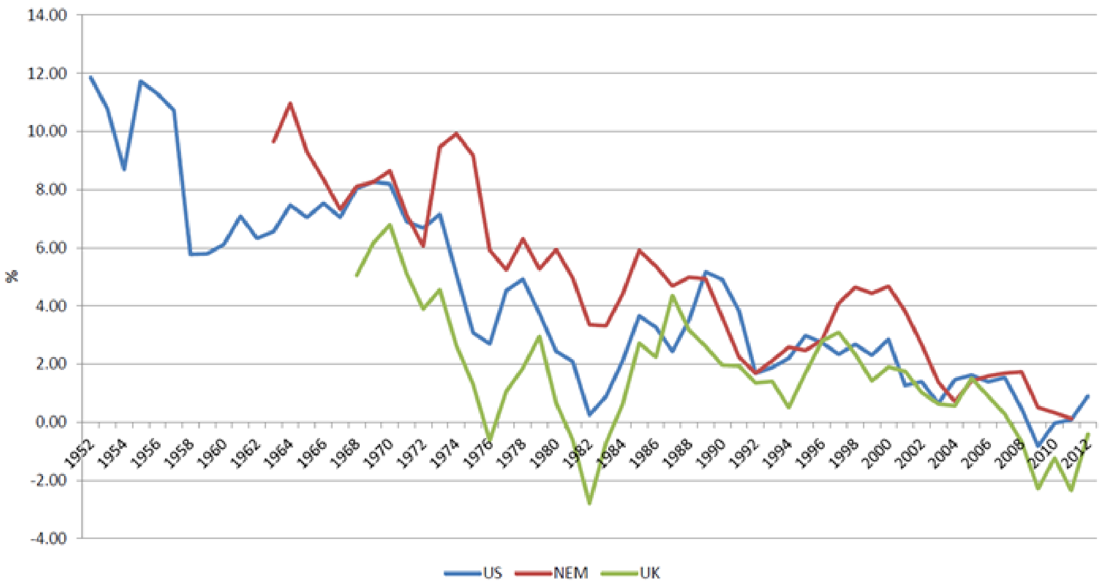
335 Significant decreases are expected with Ford announcing it will stop making cars at North Shore in 2016. Further detail is provided at http://www.ford.com.au/about/newsroom-result?article=1249024395989.

336 United Energy outlined the benefits from the AMI (smart meter) rollout, including, improved peak load transformer data the ability to rebalance overloaded phases to improve network utilisation on peak demand days and reduce the need for network augmentation, Source: United Energy, Regulatory proposal 2015-20, p. 18.

337 Recent rule changes have led to Powercor, as well as other Victorian service providers, to introduce new cost reflective tariff structures that are likely to have implications for maximum demand Further detail is provided at http://www.aemc.gov.au/News-Center/What-s-New/Announcements/New-rules-for-cost-reflective-network-prices.

338 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 11.

Figure 6.27 Long term trends in electricity growth rates



Source: Energy Supply Association of Australia (ESAA).[339]

C.4 Powercor's forecasting methodology and assumptions

Our next step in examining Powercor's forecasts of maximum demand is to look at Powercor's methodology and whether it is likely to result in a demand forecast that reflects a realistic expectation of demand. We have relied on a report by our internal economic consultant, Dr Darryl Biggar, and some of our observations about recent trend in maximum demand.

Powercor's forecasting methodology (from CIE), like most forecasting models, assumes that there is a fixed and unchanging underlying relationship between demand and key demand drivers. It assumes that this relationship can be accurately estimated using historic data and that these relationships that have been observed in the past will continue into the future. However, if there are changes in the market which are not captured in the forecasting model, the model will not provide a reliable guide to future outcomes.

This is shown in Dr Biggar's 2015 report on the Victorian electricity distributors' demand forecasting methodologies.[340] Dr Biggar's analysis, replicated in Figure 6.28, provides a simplistic illustration which shows what can happen when the assumed

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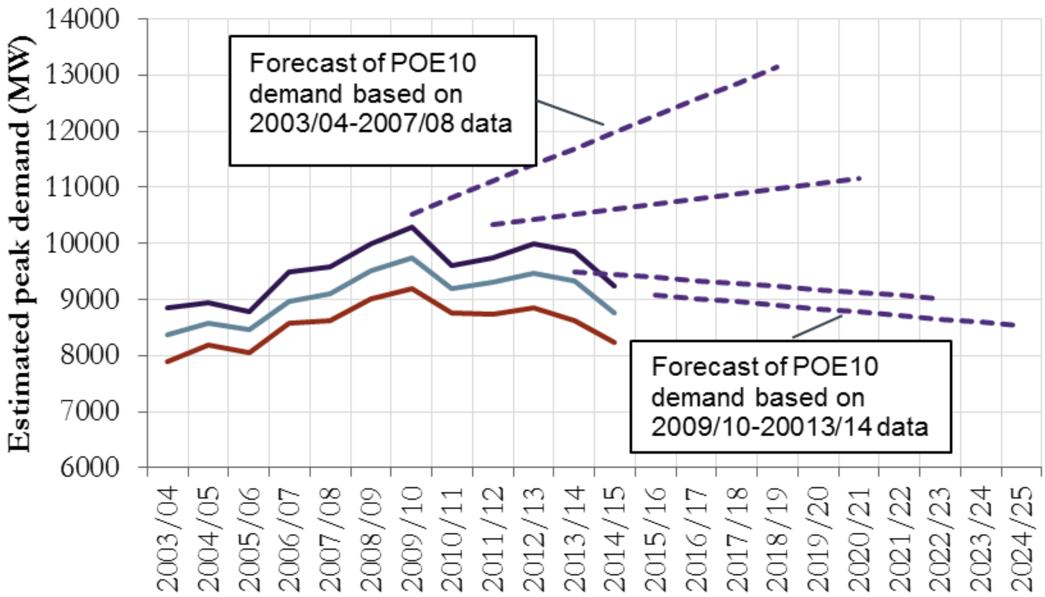
339 Economic and Social Outlook Conference 2014, ESAA, 3 July 2014, p. 7, accessed on 18 August 2015 at: http://www.melbourneinstitute.com/downloads/conferences/Outlook2014/Outlook2014_slides/6_Warren,%20Matthew.pdf.

340 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 8.

drivers of demand do not capture a fixed and unchanging relationship between demand and the key drivers. In this example it is assumed that the primary driver of demand is time (a simple time trend). But as Figure 6.28 shows, there appears to be no fixed relationship between peak demand and time. In the first half of the last decade, peak demand growth was increasing rapidly. Since around 2009 it appears that peak demand has been declining. This illustrates that a model, which assumes a simple fixed relationship between peak demand and time would likely give unreliable forecasts of future peak demand.[341]

Figure 6.28 Illustration of future forecasts of POE10 levels based on the most recent five years of data



Source: Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 10.

Similarly, Dr Biggar observed that CIE's modelling enforces a single relationship between maximum demand and weather and other key drivers across the entire ten year period which is assumed to continue to hold in the future.[342]

Dr Biggar stated that CIE's methodology is econometrically sophisticated, and has been prepared in good faith using tools which have proven robust and effective in the past.[343] However, CIE's models implicitly forecast a return to long term growth through the assumption that the longer term structural relationships will continue to hold in the

[341] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 8.

[342] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 22.

[343] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 1 and 22.

future.[344] Dr Biggar's 2015 report noted that this approach is acceptable provided that the model has accurately and fully captured all of the key drivers of peak demand. However, after examining the drivers used by CIE, Dr Biggar expressed concern that these drivers may not be able to capture the recent apparent change in demand drivers noted above (such as investment in solar PV and increasing energy efficiency). As a consequence Dr Biggar expressed concern that CIE's models do not allow for the potential changes that we may be observing for the electricity market in Victoria and recent declines in demand.[345] The evidence presented in section C.3 above suggests that average demand growth is likely to be low, zero or negative in the near future.

We have used AEMO's connection point demand forecasts as an independent comparison to Powercor's forecasts. In September 2014, AEMO published its report on connection point demand forecasts for each of the Victorian electricity distributors for the 2014–2023 period. As noted previously, AEMO forecasts low or zero demand growth over the 2016–20 period.

AEMO's connection point demand forecasts are based on a methodology developed by ACIL Allen, which was developed after consultation during 2012–13 with all distribution businesses.[346] This methodology does not assume a particular long term structural relationship for demand over time. AEMO has decided to adopt a 'cubic' relationship with historical demand and adopts an "off the point approach" (which means that the demand forecast begins at the most recent point of actual demand).[347]

ACIL Allen's "off-the-point" approach is not without its criticisms. In particular, it relies on industry knowledge and judgement to adopt an alternative to a historical linear trend and to start the forecast at the most recent point, which can be arbitrary if not based on first principles or underlying economic phenomena.[348] However, we consider it is a better model for forecasting demand for Powercor's network for 2015–20 than CIE's models. This is because ACIL Allen's models do not assume a fixed structural relationship between long term drivers of demand and certain economic factors across the entire period. In using the "off-the-point" approach ACIL Allen extrapolates the relationship between demand and the long term underlying drivers based on the most

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344 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 1.

345 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, p. 26.

346 In December 2012, the Council of Australian Governments (COAG) released its energy market reform implementation plan. In this plan, AEMO will develop independent demand forecasts in 2013-14 to inform the AER's assessment of infrastructure investment plans submitted by Network Service Providers . Further detail is provided at http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

347 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 55-56.

348 This was a source of criticism in Frontier Economics' peer review of AEMO's demand forecasts. See Frontier, "High level review of transmission connection point forecasts: Victoria", A report prepared for the Australian Energy Market Operator, September 2014.

recent actual demand value. Because of this, we consider that AEMO's forecast is more likely to reflect a realistic expectation of demand over the 2016–20 period.

Powercor submitted that CIE's demand forecasting methodology is consistent with ACIL Allen's.[349] We found that while CIE broadly undertook the same forecasting stages as ACIL Allen, the key input assumptions were different. This led to different results. Some of the differences observed by Powercor are:[350]

- CIE produced maximum demand econometric models for each terminal station and at the total network level, whereas AEMO only undertook economic modelling at the state level.
- CIE did not observe any integration of maximum demand and energy forecast models, whereas AEMO's forecasts had energy growing faster than maximum demand.
- Powercor disagrees with AEMO's post modelling adjustments for:
    - Contribution of solar PV to maximum demand
    - Assumptions and application of forecast energy efficiency.
- Difference in observation for Probability of Exceedance (PoE) weather normalisation and terminal station forecasts starting point.
- Powercor raised concern with reconciliation of National Electricity Forecasting Report (NEFR) forecasts with transmission connection point forecasts.

We took these into account. On balance, we are of the view that the key difference between the results from Powercor's and AEMO's forecasts is whether the relationship adopted between demand and temperature accurately reflects fundamental long term trends. In forming our view, we have recognised that each model has strengths and limitations. These are highlighted in our analysis above and Dr Biggar's report.[351] We do not consider Powercor's model appropriately reflects the changes we have observed in the electricity market. As stated previously, we are open to Powercor submitting an alternative forecast that captures the changes that we are observing for the electricity market in Victoria and recent declines in demand.

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349 Powercor, *Regulatory Proposal 2016–20,* April 2015, p. 90.

350 Powercor, *Presentation to the AER*, *Spatial demand forecasts CitiPower and Powercor*, 15 July 2015.

351 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, August 2015, pp. 21–22.

D Predictive modelling approach and scenarios

This section provides a guide to our repex modelling process. It sets out:

- the background to the repex modelling techniques
- discussion of the data required to apply the repex model
- detail on how this data was specified
- description of how this data was collected and refined for inclusion in the repex model
- the outcomes of the repex model under various input scenarios.

This supports the detailed and multifaceted reasoning outlined in appendix A.

D.1 Predictive modelling techniques

In late 2012 the AEMC published changes to the National Electricity and National Gas Rules.[352] In light of these rule changes the AER undertook a "Better Regulation" work program, which included publishing a series of guidelines setting out our approach to regulation under the new rules.[353]

The expenditure forecast assessment Guideline (Guideline) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.[354] It lists predictive modelling as one of the assessment techniques we may employ when assessing a distributor's repex. We first developed and used our repex model in our 2009–10 review of the Victorian electricity DNSPs' 2011–15 regulatory proposals and have also used it subsequently.[355]

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.[356] At a basic level, the model predicts the volume of a distributor's assets that may need to be replaced over each of the next 20 years. This prediction is made by looking at the age of assets already in commission, and the time at which, on average, these assets would be expected to be replaced. The unit cost of replacing the assets is used to provide an estimate of replacement expenditure. The data used in the model is derived from the distributor's regulatory information notice (RIN) responses and from the outcomes of the unit cost and

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

353 See AER *Better regulation reform program* web page at http://www.aer.gov.au/Better-regulation-reform-program.

354 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013; AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, November 2013.

355 AER Determinations for 2011–15 for CitiPower, Jemena, Powercor, SP AusNet, and United Energy.

356 AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

replacement life benchmarking across all distribution businesses in the NEM. These processes are described below.

D.2 Data specification process

Our repex model requires the following input data on a distributor's network assets:

- the age profile of network assets currently in commission
- expenditure and replacement volume data of network assets
- the mean and standard deviation of each asset's replacement life (replacement life).

Given our intention to apply unit cost and replacement life benchmarking techniques, we defined the model's input data around a series of prescribed network asset categories. We collected this information by issuing two types of RINs:

1. "Reset RINs" which we issued to distributors requiring them to submit this information with their upcoming regulatory proposal

2. "Category analysis RINs" which we issued to all distributors in the NEM.

The two types of RIN requested the same historical asset data for use in our repex modelling. The Reset RIN also collected data corresponding to the distributors proposed forecast repex over the 2016–20 regulatory control period. In both RINs, the templates relevant to repex are sheets 2.2 and 5.2.

For background, we note that in past determinations, our RINs did not specify standardised network asset subcategories for distributors to report against. Instead, we required the distributors to provide us data that adhered to broad network asset groups (e.g. poles, overhead conductors etc.). This allowed the distributor discretion as to how its assets were subcategorised within these groups. The limited prescription over asset types meant that drawing meaningful comparisons of unit costs and replacement lives across distributors was difficult.[357]

Our changed approach of adopting a standardised approach to network asset categories provides us with a dataset suitable for comparative analysis, and better equips us to assess the relative prices of capital inputs as required by the capex criteria.[358]

When we were formulating the standardised network assets, we aimed to differentiate the asset categorisations where material differences in unit cost and replacement life existed. Development of these asset subcategories involved extensive consultation

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[357] The repex model has been applied in the Victorian 2011–15 and Aurora Energy 2012–17 distribution determinations; AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

[358] NER, cl. 6.5.7(e)(6).

with stakeholders, including a series of workshops, bilateral meetings and submissions on data templates and draft RINs.[359]

D.3 Data collection and refinement

The new RINs represent a shift in the data reporting obligations on distributors. Given this is the first period in which the distributors have had to respond to the new RINs, we undertook regular consultation with the distributors. This consultation involved collaborative and iterative efforts to refine the datasets to better align the data with what we require to deploy our assessment techniques. We consider that the data refinement and consultation undertaken after the RINs were received, along with the extensive consultation carried out during the Better Regulation process, provide us with reasonable assurance of the data's quality for use in this part of our analysis.

To aid distributors, an extensive list of detailed definitions was included as an appendix to the RINs. Where possible, these definitions included examples to assist distributors in deciding whether costs or activities should be included or excluded from particular categories. We acknowledge that, regardless of how extensive and exhaustive these definitions are, they cannot cater for all possible circumstances. To some extent, distributors needed to apply discretion in providing data. In these instances, distributors were required to clearly document their interpretations and assumptions in a “basis of preparation” statement accompanying the RIN submission.

Following the initial submissions, we assessed the basis of preparation statements that accompanied the RINs to determine whether the data submitted complied with the RINs. We took into account the shift in data reporting obligations under the new RINs when assessing the submissions. Overall, we considered that the repex data provided by all distributors was compliant. We did find a number of instances where the distributors’ interpretations did not accord with the requirements of the RIN but for the purpose of proceeding with our assessment of the proposals, these inconsistencies were not substantial enough for a finding of non-compliance with the NEL or NER requirements.[360]

Nonetheless, in order that our data was the most up to date and accurate, we did inform distributors, in detailed documentation, where the data they had provided was not entirely consistent with the RINs, and invited them to provide updated data. Refining the repex data was an iterative process, where distributors returned amended consolidated RIN templates until such time that the data submitted was fit for purpose.

D.4 Benchmarking repex asset data

As outlined above, we required the following data on distributors' assets for our repex modelling:

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[359] See AER *Expenditure forecast assessment guideline—Regulatory information notices for category analysis* webpage at http://www.aer.gov.au/node/21843.

[360] NER, cl. 6.9.1.

- age profile of network assets currently in commission
- expenditure, replacement volumes and failure data of network assets
- the mean and standard deviation of each asset's replacement life.

All NEM distributors provided this data in the Reset RINs and Category analysis RINs under standardised network asset categories.

To inform our expenditure assessment for the distributors currently undergoing revenue determinations,[361] we compared their data to the data from all NEM distributors. We did this by using the reported expenditure and replacement volume data to derive benchmark unit costs for the standardised network asset categories. We also derived benchmark replacement lives (the mean and standard deviation of each asset's replacement life) for the standardised network asset categories.

In this section we explain the data sets we constructed using all NEM distributors' data, and the benchmark unit costs and replacement lives we derived for the standardised network asset categories.

D.4.1 Benchmark data for each asset category

For each standardised network asset category where distributors provided data we constructed three sets of data from which we derived the following three sets of benchmarks:[362]

- benchmark unit costs
- benchmark means and standard deviations of each asset's replacement life (referred to as "uncalibrated replacement lives" to distinguish these from the next category)
- benchmark calibrated means and standard deviations of each asset's replacement life.

Our process for arriving at each of the benchmarks was as follows. We calculated a unit cost for each NEM distributor in each asset category in which it reported replacement expenditure and replacement volumes. To do this:

- We determined a unit cost for each distributor, in each year, for each category it reported under. To do this we divided the reported replacement expenditure by the reported replacement volume.
- Then we determined a single unit cost for each distributor for each category it reported under. We first inflated the unit costs in each year using the CPI index.[363]

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[361] Vic, SA and QLD distribution network service providers—AusNet Services, United Energy, Jemena, Powercor, CitiPower, SA Power Networks, Energex and Ergon Energy.

[362] We did not derive benchmark data for some standardised asset categories where no values were reported by any distributors, or for categories distributors created outside the standardised asset categories.

[363] We took into account whether the distributor reported on calendar or financial year basis.

We then calculated a single unit cost. We did this by first weighting the unit cost from each year by the replacement volume in that year. We then divided the total of these expenditures by the total replacement volume number.

We formulated two sets of replacement life data for each NEM distributor:

- The replacement life data all NEM distributors reported in their RINs.
- The replacement life data we derived using the repex model for each NEM distributor. These are also called calibrated replacement lives. The repex model derives the replacement lives that are implied by the observed replacement practices of a distributor. That is, the lives are based on the data a distributor reported in the RIN on its replacement expenditure and volumes over the most recent five years, and the age profile of its network assets currently in commission. In this way, they can be said to derive from the distributors observed replacement practices. The calibrated lives the repex model derives can differ from the replacement lives a distributor reports.

We derived the benchmarks for an asset category using each of the three data sets above. That is, we derived a set of benchmark unit costs, benchmark replacement lives, and benchmark calibrated replacement lives for an asset category. To differentiate the two sets of benchmarked replacement lives, we refer to the benchmarks based on the calibration process as 'benchmarked calibrated replacement lives' and those based on replacement lives reported by the NEM distributors as 'benchmarked uncalibrated replacement lives'. We applied the method outlined below to each of the three data sets.

We first excluded Ausgrid's data, since it reported replacement expenditure values as direct costs and overheads. Therefore these expenditures were not comparable to all other NEM distributors which reported replacement expenditure as direct costs only. We then excluded outliers by:[364]

- calculating the average of all values for an asset category
- determining the standard deviation of all values for an asset category
- excluding values that were outside plus or minus one standard deviation from the average.

Using the data set excluding outliers we then determined the:

- Average value:
    - benchmark average unit cost

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[364] For the benchmarked calibrated replacement lives we performed two additional steps on the data prior to this. We excluded any means where the distributor did not report corresponding replacement expenditure. This was because zero volumes led to the repex model deriving a large calibrated mean which may not reflect industry practice and may distort the benchmark observation. We also excluded any calibrated mean replacement lives above 90 years. Although the repex model can generate these large lives, observations of more than 90 years exceed the number of years reportable in the asset age profile.

- benchmark average mean and standard deviation replacement life
- benchmark average calibrated mean and standard deviation replacement life.

- One quartile better than the average value:
  - benchmark first quartile unit cost (below the mean)
  - benchmark third quartile uncalibrated mean replacement life (above the mean)
  - benchmark third quartile calibrated mean replacement life (above the mean).
- 'Best' value:
  - benchmark best (lowest) unit cost
  - benchmark best (highest) uncalibrated mean replacement life
  - benchmark best (highest) calibrated mean replacement life.[365]

D.5 Repex model scenarios

As noted above, our repex model uses an asset age profile, expected replacement life information and the unit cost of replacing assets to develop an estimate of replacement volume and expenditure over a 20 year period.

The asset age profile data provided by the distributors is a fixed piece of data. That is, it is set, and not open to interpretation or subject to scenario testing.[366] However, we have multiple data sources for replacement lives and unit costs, being the data provided by the distributors, data that can be derived from their performance over the last five years, and benchmark data from all distributors across the NEM. The range of different inputs allows us to run the model under a number of different scenarios, and develop a range of outcomes to assist in our decision making.

We have categorised three broad input scenarios under which the repex model may be run. These are explained in greater detail within our Replacement expenditure model handbook.[367] They are:

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365 We did not determine quartile or best values for the uncalibrated standard deviation and calibrated standard deviation replacement lives. This is because we used the benchmark average replacement lives (mean and standard derivation) for comparative analysis between the distributors. However, the benchmark quartile and best replacement life data was for use in the repex model sensitivity analysis. The repex model only requires the mean component of an asset's replacement life as an input. The repex model then assumes the standard deviation replacement life of an asset is the square root of the mean replacement life. The use of a square root for the standard deviation is explained in more detail in our Replacement expenditure model handbook; AER, *Electricity network service provider: Replacement expenditure model handbook*, November 2013.

366 It has been necessary for some distributors to make assumptions on the asset age profile to remove double counting. This is detailed at the end of this appendix.

367 AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013.

(1) The Base scenario – the base scenario uses inputs provided by the distributor in their RIN response. Each distributor provided average replacement life data as part of this response. As the distributors did not explicitly provide an estimate of their unit cost, we have used the observed historical unit cost from the last five years and the forecast unit cost from the upcoming regulatory control period in the base scenario.

(2) The Calibrated scenario – the process of "calibrating" the expected replacement lives in the repex model is described in the AER's replacement expenditure handbook.[368] The calibration involves deriving a replacement life and standard deviation that matches the distributor's recent historical replacement practices (in this case, the five years from 2011 to 2015). The calibrated scenario benchmarks the business to its own observed historical replacement practices.

(3) The Benchmarked scenarios – the benchmarked scenarios use unit cost and replacement life inputs from the category analysis benchmarks. These represent the observed costs and replacement behaviour from distributors across the NEM. As noted above, we have made observations for an "average", "first or third quartile" and "best performer" for each repex category, so there is no single "benchmarked" scenario, but a series of scenarios giving a range of different outputs.

The model can also take into account different wooden pole staking/stobie pole plating rate assumptions (see section D.3 for more information on this process). For the Victorian distributors, who exhibit high wooden pole staking rates relative to the rest of the NEM, we have not chosen to test different staking scenarios. A full list of the scenario outcomes is provided in Figure 6.29 and Figure 6.30 below.

Figure 6.29 Repex model outputs – replacement lives

Replacement lives	
Base case (RIN)	$7.53 billion
Calibrated lives	$375 million
Benchmarked calibrated average	$675 million
Benchmarked calibrated third quartile	$477 million
Benchmarked calibrated best	$338 million

Source: AER analysis, using historic unit costs.

[368] AER, *Electricity network service providers: Replacement expenditure model handbook*, November 2013, pp. 20–21.

Figure 6.30 Repex model outputs − unit costs

Unit cost	
Benchmarked average	$377 million
Benchmarked first quartile	$282 million
Benchmarked best	$242 million

Source: AER analysis, using calibrated replacement lives.

Data assumptions

Certain data points were not available for use in the model. For unit costs, this arose either because the distributor did not incur any expenditure on an asset category in the 2011–15 regulatory control period (used to derive historical unit costs) or had not proposed any expenditure in the 2016–20 regulatory control period (used to derive forecast unit costs). If both these inputs were not available, we used the benchmarked average unit cost as a substitute input.

In addition, we did not use a calibrated asset replacement life where the distributor did not replace any assets during the 2011−15 regulatory control period. This is because the calibration process relies on replacement volumes over the five year period to derive a mean and standard deviation, and using a value of zero may not be appropriate for this purpose. In the first instance, we substituted these values with the average calibrated replacement life of the broad asset group to which the asset subcategory belonged. Where this was not available, we used the benchmarked calibrated replacement life or the base case replacement life from the distributor.

While the majority of the data was provided in a form suitable for modelling, limited adjustments needed to be made for some of the data. For Powercor we converted their forecast replacement volumes for service lines from kilometres to spans using the assumptions provided in its basis of preparation for the 2014 category analysis RIN.

Un-modelled repex

As detailed in the AER's repex handbook, the repex model is most suitable for asset categories and groups with a moderate to large asset population of relatively homogenous assets. It is less suitable for assets with small populations or those that are relatively heterogeneous. For this reason, we chose to exclude certain data (or asset categories) from the modelling process, and did not use predictive modelling to directly assess these categories. However, where suitable data was available, we used predictive modelling to test our other findings on these categories. We decided to exclude SCADA repex from the model for this reason. Expenditure on pole top structures was also excluded, as it is related to expenditure on overall pole replacement and modelling may result in double counting of replacement volumes. Other excluded categories are detailed in appendix D.3 of this preliminary decision.[369]

D.6 The treatment of staked wooden poles

The staking of a wooden pole is the practice of attaching a metal support structure (a stake or bracket) to reinforce an aged wooden pole.[370] The practice has been adopted by distributors as a low-cost option to extend the life of a wooden pole. These assets require special consideration in the repex model because, unlike most other asset types, they are not installed or replaced on a like for like basis. To understand why this requires special treatment, we have described below the normal like-for-like assumption used in the repex model, why staked poles do not fit well within this assumption, and how we adapt the model inputs to take account of this.

D.6.1 Like-for-like repex modelling

Replacement expenditure is normally considered to be on a like-for-like basis. When an asset is identified for replacement, it is assumed that the asset will be replaced with its modern equivalent, and not a different asset. For example, conductor rated to carry low voltage will be replaced with conductor of the same rating, not conductor rated for high voltage purposes.

The repex model predicts the volume of old assets that need to be replaced, not the volume of new assets that need to be installed. This is simple to deal with when an asset is replaced on a like-for-like basis – the old asset is simply replaced by a new asset of the same kind. It follows that the volume of assets that needs to be replaced where like-for-like replacement is appropriate match the volume of new assets to be installed. The cost of replacing the volume of retired assets is the unit cost of the new asset multiplied by the volume of assets that need to be replaced.

D.6.2 Non-like-for-like replacement

Where old assets are commonly replaced with a different asset, we cannot simply assume the cost of the new asset will match the cost of the old asset's modern equivalent. As the repex model predicts the number of old assets that need to be replaced, it is necessary to make allowances for the cost of a different asset in determining the replacement cost. In running the repex model, the only category where this was significant was wooden poles.

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[369] For AusNet Services, we ran a limited set of modelling scenarios on SCADA and other repex, as suitable data was available. This was used to test the findings from our other techniques. For Powercor, we ran limited scenarios on pole top structures to test the findings from our other techniques. For each of these, we relied more on other assessment techniques, as detailed in Appendix A.

[370] The equivalent practice for stobie poles is known as "plating", which similarly provides a low cost life extension. SA Power Networks carries out this process. We applied the same process for modelling SA Power Networks' stobie pole plating data as we have for staked wooden poles. However, for simplicity, this section only refers to the staking process.

Staked and unstaked wooden poles

The life of a wooden pole may be extended by installing a metal stake to reinforce its base. Staked wooden poles are treated as a different asset in the repex model to unstaked poles. This is because staked and unstaked poles have different expected lives and different costs of replacement.

When a wooden pole needs to be replaced, it will either be staked or replaced with a new pole. The decision on which replacement type will be carried out is made by determining whether the stake will be effective in extending the pole's life, and is usually based on the condition of the pole base. If the wood at the base has deteriorated too far, staking will not be effective, and the pole will need to be replaced. If there is enough sound wood to hold the stake, the life of the pole can be extended, and a stake can be installed. Consequently, there are two possible asset replacements (and two associated unit costs) that may be made by the distributor – a new pole to replace the old one or nailing a stake to the old pole.

The other non-like-for-like scenario related to staking is where an in-commission staked pole needs to be replaced. Staking is a one-off process. When a staked pole needs to be replaced, a new pole must be installed in its place. The cost of replacing an in-commission staked pole is the cost of a new pole.

Unit cost blending

We use a process of unit cost blending to account for the non-like-for-like asset categories.

For unstaked wooden poles that need to be replaced, there are two appropriate unit costs: the cost of a new pole; and the cost of staking an old pole. We have used a weighted average between the unit cost of staking and the unit cost of pole replacement to arrive at a blended unit cost.[371] We ran the model under a variety of different weightings – including the observed staking rate of the business and observed best practice from the distributors in the NEM.

For the Victorian distributors, we adopted their own observed staking ratio.

For staked wooden poles being replaced, in the first instance, we used historical data from the distributors on the proportion of different voltage staked wooden poles being replaced to approximate the volume of each new asset going forward.[372] The unit cost of replacing a staked wooden pole is a weighted average based on the historical proportion of pole types replaced. Where historical data was not available, we used the

[371] For example, if a distributor replaces a pole with a new pole 50 per cent of the time, and stakes the pole the other 50 per cent of the time, the blended unit cost would be a straight average of the two unit costs. If the mix was 60:40, the unit cost would be weighted accordingly.

[372] Poles with different maximum voltages have different unit costs. An assumption needs to be made to determine, for example, how many new ">1kv poles" and how many new "1kv-11kv" need to be installed to replace the staked wooden poles.

asset age data to determine what proportion of the network each pole category represented, and used this information to weight the unit costs.

D.7 Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when determining calibrated replacement lives. This is because historical volumes of replacements are used in calibration. The RIN responses provide us with information on the volume of new assets installed over the last five years. However, the model predicts the volume of old assets being replaced. Since the replacement of staked poles is not on a like-for-like basis, we make an adjustment for the calibration process to function correctly. That is, we need to know the number of staked poles that reach the end of their economic life so we can calibrate the model for when these assets are replaced. The category analysis RIN currently only provides us with information on how many new stakings have taken place, rather than how many were actually replaced. We sought, and were provided with this information directly from the distributors.

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