2016–2020 Price Reset

Appendix E
Capital expenditure

April 2015

Powercor
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1 Summary

Powercor plans to invest around **$2.015 billion** of capital expenditure over the 2016–2020 regulatory control period. The capital expenditure forecasts have been carefully prepared to ensure that Powercor will be able to continue to deliver a reliable supply of electricity at least cost to customers, including at times of peak demand on the network, as well as to connect new customers. Powercor must also undertake the required activities to mitigate the risk of its assets contributing to starting a bushfire.

This chapter sets out Powercor's forecasts for capital expenditure for standard control services for the 2016-2020 regulatory control period.

Capital expenditure is required to continue to meet expected demand and connect new customers and to safely deliver a reliable electricity supply to customers, with the appropriate power quality, while striving to maintain the load at risk and health of the network assets. In addition, Powercor's capital expenditure program is necessary to address applicable regulatory obligations and requirements including the delivery of electricity in a safe manner, and reducing the risk of its assets starting a bushfire.

As demonstrated in the benchmarking chapter, Powercor is one of the most efficient distributors in Australia. The rigorous cost controls and condition-based approach to maintaining assets has resulted in a reliable electricity supply at low cost.

Powercor has asked its stakeholders for views on the business, to better understand their priorities and concerns. Generally, stakeholders:

- are satisfied or very satisfied with the current level of reliability;[1]
- in regional areas support local investment to increase capacity for businesses and households or to address particular reliability concerns;
- do not want an increase in their electricity bill except to reduce the risk of fire danger arising from the network;
- are supportive of creating a smarter grid that facilitates new technologies and further utilises data from smart meters to enable Powercor to better manage and react to changes in the network; and
- seek to better understand their energy consumption data to enable them to be more informed about their usage and consumption choices.

Powercor has taken the stakeholder views and expectations into account in developing the expenditure forecasts for the 2016–2020 regulatory control period, which is set out in table 1.1.

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[1] For example, see Colmar Brunton Research, *Powercor Stakeholder engagement research – online customer survey results*, 18 July 2014, p. 36

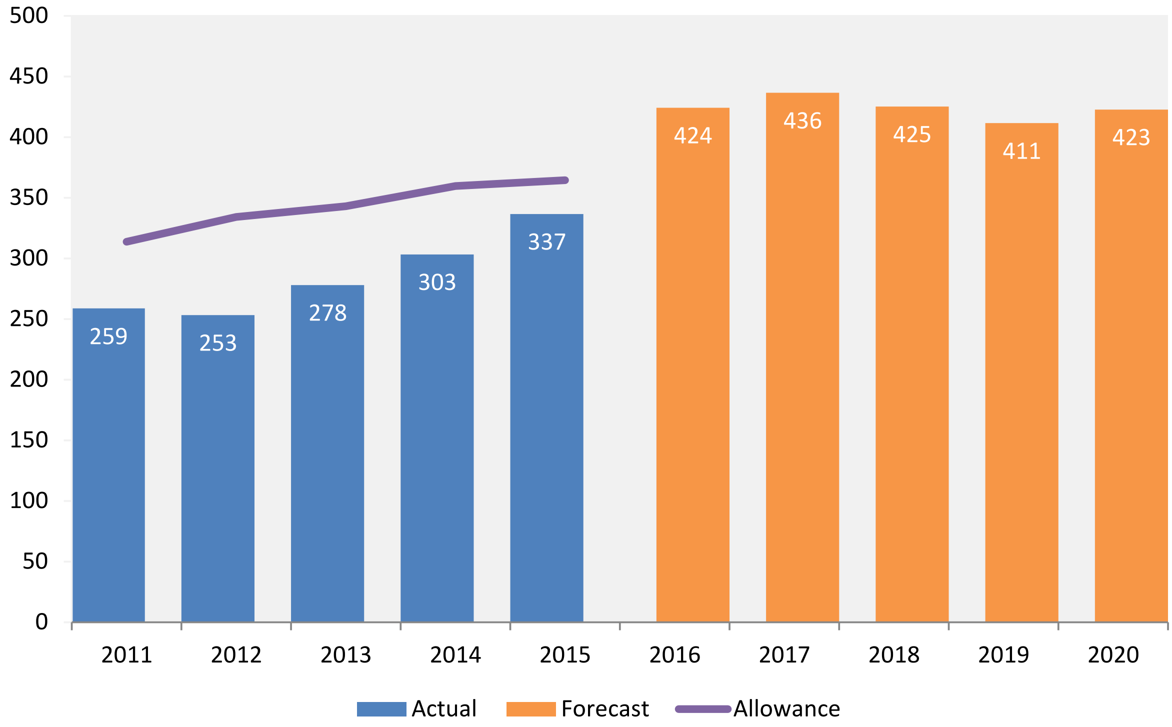
Table 1.1 Total capital expenditure ($ million, 2015)

	2016	2017	2018	2019	2020	Total
Replacement	120.2	117.5	133.7	139.2	154.1	664.7
Augmentation	35.6	57.0	56.4	45.3	48.3	242.6
Connections	166.1	170.8	147.5	143.7	146.0	774.1
VBRC	38.4	25.7	25.5	25.9	25.4	141.0
IT and communications	41.0	41.5	37.3	32.3	23.3	175.3
Non-network	22.8	24.0	24.8	24.9	25.7	122.3
Equity raising costs	9.2	-	-	-	-	9.2
Gross direct capital expenditure	**433.4**	**436.5**	**425.2**	**411.4**	**422.7**	**2,129.1**
Plus direct overheads	37.6	39.1	40.4	41.9	43.3	202.3
Gross capital expenditure	**471.0**	**475.5**	**465.6**	**453.3**	**466.0**	**2,331.4**
Less customer contributions	69.5	76.2	59.3	55.6	55.4	316.0
Less disposals	-	-	-	-	-	-
Net capital expenditure	**401.5**	**399.3**	**406.4**	**397.8**	**410.5**	**2,015.4**

Source: Powercor

Powercor requires an increase in capital expenditure from the current regulatory control period. The profile of actual and forecast gross capital expenditure is shown in figure 1.1.

Figure 1.1 Powercor total direct gross capital expenditure 2011–2020 ($2015, million)[2]



Source: Powercor

The capital expenditure chapter is set out as follows:

- section 2 provides general information that is application to all categories of Powercor's forecast capital expenditure;
- section 3 describes the process for identifying assets that need replacement, as well as the replacement expenditure forecasts;
- section 4 describes the process for planning network augmentation and methodology for forecasting augmentation expenditure;
- section 5 sets out the process for forecasting expenditure for connections and customer-driven works;
- section 6 outlines the expenditure required as a result of the recommendations from the Victorian Bushfires Royal Commission (**VBRC**);
- section 7 discusses expenditure for information technology (**IT**) and communications;
- section 8 discusses forecasts for non-network expenditure; and
- section 9 relates to the interactions of capital and operating expenditure.

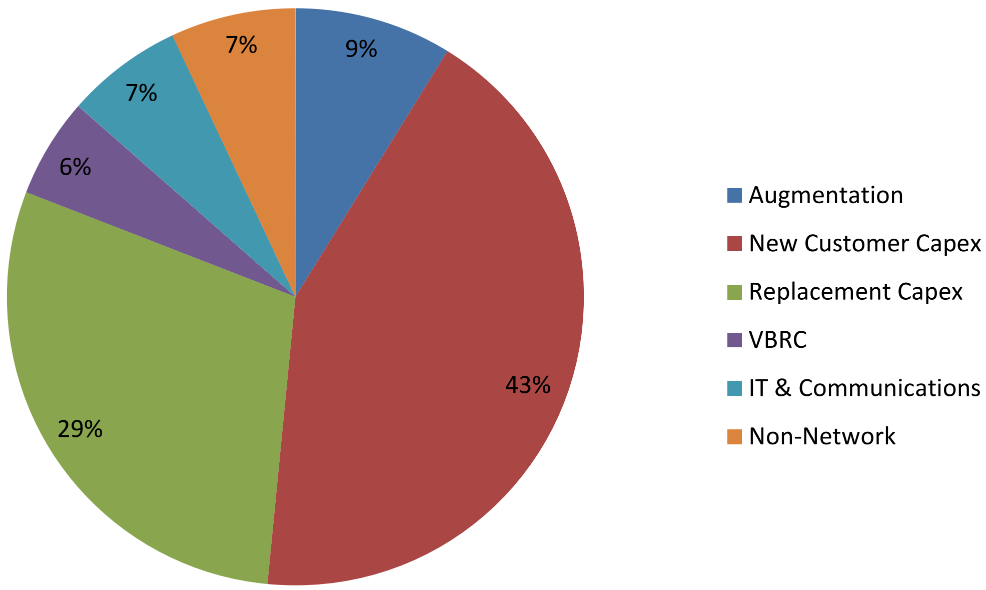
1.1 Overview of historical expenditure

Powercor's capital expenditure program during the 2011–2015 regulatory control period has delivered reliable electricity supply at an efficient cost.

[2] 2006 to 2014 are actual costs, 2015 to 2020 are forecast costs.

The largest proportion of gross capital expenditure was spent on new connections, with replacement expenditure to maintain the reliability of the network the second largest, as shown in figure 1.2.

Figure 1.2 Capital expenditure by category in the current regulatory control period



Source: Powercor

The expenditure related to the VBRC recommendations was for specific activities that Powercor was obligated to undertake during the period. These activities were funded through an additional allowance provided by the Australian Energy Regulator (**AER**) in 2012, as the obligations were not known at the time of the 2010 regulatory determination.

Powercor has underspent the AER's capital expenditure allowance for the current control period by approximately 17 per cent.

The underspend demonstrates that Powercor has responded to the incentives within the regulatory regime to invest efficiently to provide safe, reliable and secure supply of electricity. Consumers then benefit from a lower amount of capital expenditure being rolled into the Regulatory Asset Base (**RAB**) at the commencement of the 2016–2020 regulatory control period.

While Powercor has underspent overall, it has spent above the AER allowance in some categories of expenditure, and underspent in others. Notably, Powercor has:

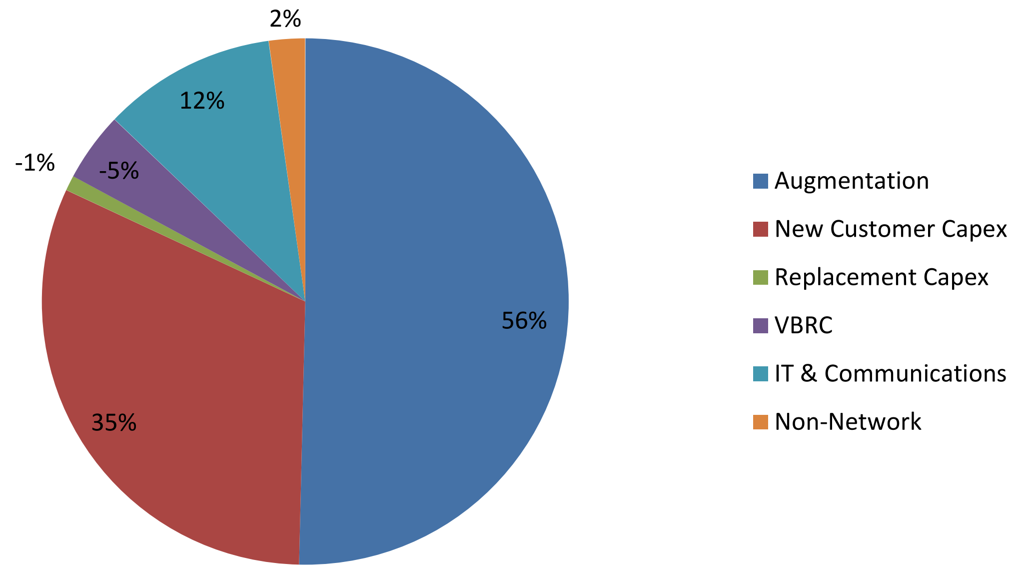
- spent more than its approved allowance for replacement expenditure and more than the approved pass through amount for VBRC related expenditure; and
- spent less than its approved allowance for augmentation expenditure and gross customer connections, where expected demand did not materialise.

The 2011-2015 regulatory control period was characterised by lower-than-expected levels of demand and customer connections. This was attributable to the Global Financial Crisis (**GFC**), where the economic slowdown reduced the number of residential connections and subdivisions from previously expected levels, as well as then having a lagged impact on demand-driven augmentations. This resulted in:

- efficient deferral of some demand-driven augmentation projects; and
- connection expenditure being lower than forecast as the AER connection allowance was based on historical average expenditure from the 2006–2009 period.

Together, the augmentation and customer connections underspend accounted for over 90 per cent of Powercor's total underspend of the AER allowance. Figure 1.3 shows how each capital expenditure category contributed to the overall underspend of the AER allowance. Overspend of the AER allowance is denoted as a negative contribution.

Figure 1.3 Contribution of capital expenditure categories to the overall underspend



Source: Powercor

It is also noted that the category of Information Technology (**IT**) and communications only included expenditure approved by the AER through the 2010 distribution determination. In the 2011-2015 regulatory control period, Powercor received an allowance for the continued deployment of Advanced Metering Infrastructure (**AMI**) under an Order In Council issued by the Victorian Government. This program diverted resources and focus from other business activities.

Greater detail on the underspend or overspend is provided in the description of each capital expenditure category in this appendix.

Impact of falling energy consumption

Debate around falling energy consumption leading to an expected decline in network expenditure has been considered in the Powercor proposal.

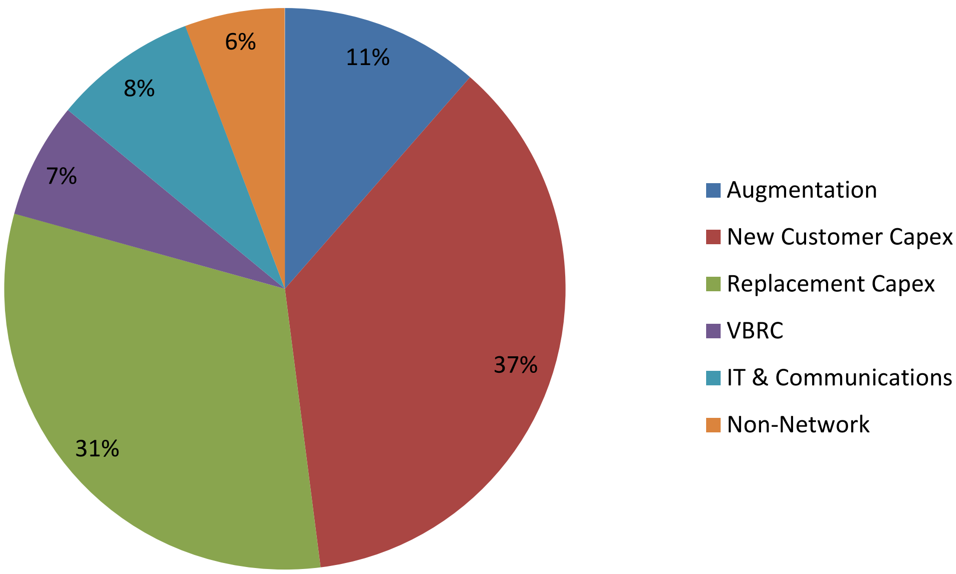
The changes in energy consumption are reflected in the peak demand forecasts, and the relationship between annual energy and peak demand is reflected through the annual load duration curves (**LDC**'s). In deciding when to undertake a major augmentation project, the LDC is used in calculating the amount of energy at risk not being supplied to customers in the event of a failure of an asset in the network. In accordance with the requirements of the regulatory test regime, Powercor will only undertake a major augmentation of the network if there is a high enough value of energy at risk to necessitate extra network capacity.

Augmentation expenditure is not a large part of Powercor's overall capital expenditure. In the current regulatory period, only 9 per cent of total capital expenditure related to augmentation works. For the 2016–2020 regulatory control period, Powercor expects to spend only 11 per cent of capital expenditure on augmentation works, with less than half of that expenditure driven by a need to address peak demand constraints on the network.

1.2 Overview of forecast expenditure

Powercor has determined the amount of capital expenditure that is needed during the 2016–2020 regulatory control period to continue to provide a safe and reliable electricity supply to customers, while also meeting its regulatory obligations. The breakdown by capital expenditure category is shown in figure 1.4.

Figure 1.4 Forecast capital expenditure by category



Source: Powercor
Note: excludes equity raising costs

The largest category of capital expenditure is expected to continue to be related to new customer connections. Replacement expenditure is expected to be the second largest category, accounting for around a quarter of capital expenditure.

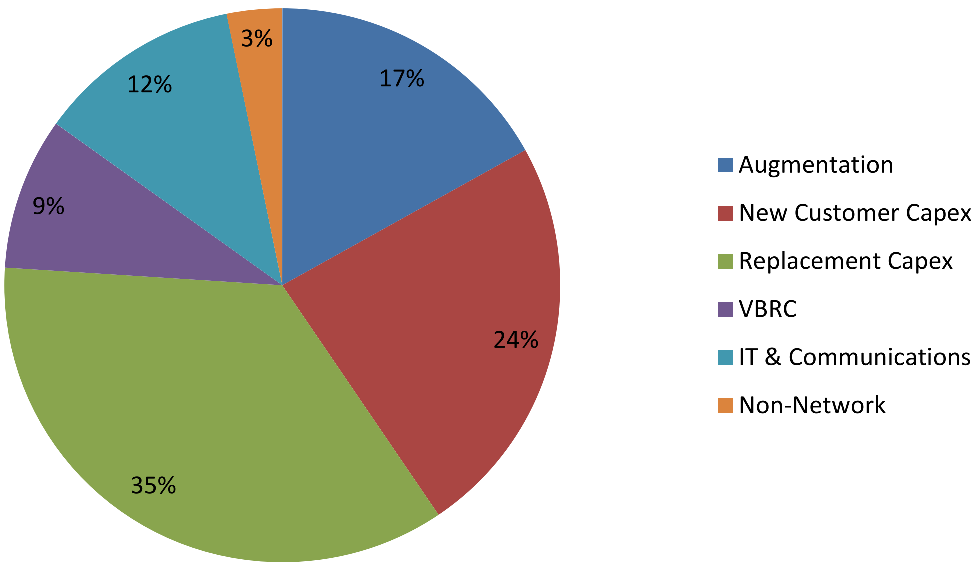
Powercor requires a 48 per cent increase in capital expenditure for standard control services in the 2016-2020 regulatory control period, compared to the actual expenditure during the current regulatory control period.

The increase in expenditure is primarily driven by the following factors:

- large and specific connection projects as a result of expansion of the dairy industry, new windfarm connections and a government initiative;
- additional network capacity required in the western suburbs of Melbourne and Greater Geelong area, as a result of population growth and transmission-level network constraints;
- increasing failure rate on lines and poles as the number of assets forecast to be defective increases, stepping up the need for further replacements; and
- activities to mitigate the risk of powerlines starting bushfires in response to the VBRC.

Figure 1.5 shows the percentage contribution by capital expenditure category of the increase in expenditure for the 2016–2020 regulatory control period compared with the current regulatory period.

Figure 1.5 Contribution of capital expenditure categories to forecast increase



Source: Powercor
Note: excludes equity raising costs

Additionally, the forecasts include expenditure to allow Powercor to continue to innovate on the network as its moves towards a smarter grid, where consumers are empowered to make choices about their energy consumption which ultimately will drive investment in, and drive development of, the electricity distribution sector. This expenditure partly explains the increase in forecast for IT and communications systems.

Innovative expenditure

During the 2016–2020 regulatory control period, Powercor intends to undertake innovative initiatives on the network which draws upon recent technological advancements to enable better interaction with, and provision of improved service to, customers. The innovations include:

- additional smart voltage regulators on the high voltage network to enable more effective management of voltage levels at the times when the power flow reverses direction in areas with a high penetration of rooftop solar photovoltaic (**PV**) equipment;
- sophisticated analytics to dynamically manage the network using the energy consumption data available from smart meters;
- improved customer response to localised outages via direct communication to each smart meter; and
- managing assets more efficiently by remote condition diagnostics and condition alerts.

Powercor's forecasts are discussed in more detail in each section of this appendix.

2 General matters applicable to all capital expenditure categories

This section provides an overview of general matters which relate to all capital expenditure categories, including a high level overview of the forecasting methodology and the deliverability of the network-related works.

2.1 Categorisation of expenditure

Powercor's capital expenditure forecasts have been broken down into the following categories of expenditure, as set out in the AER's Expenditure Forecast Assessment Guideline:[3]

- replacement;
- augmentation;
- connection and customer driven works; and
- non-network.

An additional category has been included for recommendations as a result of the VBRC. The requirements imposed on Powercor generally require the installation of new equipment into the network, and thus do not align with the AER's categories of replacement of existing equipment, or augmentation resulting in the increase in capacity of the network. The separate categorisation of VBRC may also assist the AER in comparison of this regulatory proposal against forecast expenditure in other jurisdictions.

The non-network category noted above is further disaggregated into the following sub-categories, again using the categories set out in the AER's Expenditure Forecast Assessment Guideline:[4]

- IT and communications;
- motor vehicles;
- property;
- other; and
- Supervisory Control and Data Acquisition (**SCADA**) and network control.

The IT and communications category contains a significant amount of expenditure. As a result, this expenditure is discussed separately from the remaining categories of non-network expenditure in this appendix.

The AER's Regulatory Information Notice (**RIN**) issued for the purposes of making a distribution determination for the regulatory control period from 1 January 2016 to 31 December 2020 (**Reset RIN**) requires some expenditure to be classified in different categories from those identified above. For example, expenditure for field based devices and communications fibre that form part of the SCADA network are included Template 2.3 of the Reset RIN which relates to augmentation expenditure. Powercor has therefore only included the non-field based costs associated with the SCADA network in the non-network capital expenditure.

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3 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 57.

4 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 196.

Similarly, VBRC expenditure is contained within Template 2.3 of the Reset RIN relating to augmentation, with the exception of automatic circuit reclosers (**ACR**s) on single earth wire return (**SWER**) lines and multi-circuit rebuilds which are included in the replacement expenditure categories in the Reset RIN.

Powercor has completed the Reset RIN in the manner prescribed by the AER.

Capitalised overheads

Direct overheads, which are overhead costs directly related to operating the network such as the control room or local network planners and management, are calculated using the 'revealed cost approach' that is used for forecasting operating expenditure. That is, the actual direct overheads incurred in 2014 are escalated for the 2016–2020 regulatory control period using the scale escalators identified in the operating expenditure chapter of the Regulatory Proposal.

Powercor does not consider that there is any reasonable scope for ambiguity in categorisation of direct overheads. These costs are applied to all capital expenditure categories with the exception of IT and communications, motor vehicle, property and other.

2.2 Forecasting approach

This section overviews the approach used to forecast capital expenditure, as well as addressing high level matters associated with the forecasts.

2.2.1 Preparation of forecasts

In preparing the capital expenditure forecasts, Powercor notes that:

- the preparation of capital expenditure forecast was consistent with the budgetary, planning and governance processes used in the operation of the business;
- rigorous checks were made to the forecasts, including reviews by subject matter experts, senior managers and the General Manager of the respective business unit, as well as other quality assurance steps to ensure that the amounts are free from error;
- rigorous checks were made to the various models used in preparing the forecasts, including reviews by external consultants where appropriate; and
- the forecasts are consistent with the requirements for prudency and efficiency of capital expenditure, and thus when the resulting amounts are translated into the estimated impact on the future electricity bill of customers (per section 13.9 of the regulatory proposal), any price increases are minimised to ensure the expenditure is in the long term interests of consumers.

The forecasts for capital expenditure have been properly allocated to standard control services in accordance with the principles and policies in Powercor's approved Cost Allocation Method (**CAM**).

The forecasts have also been prepared to ensure that Powercor continues to comply with its regulatory obligations. The obligations, and their relevance to the regulatory proposal, are listed in Reset RIN Template 7.3. In some cases, this appendix also discusses how the obligations have been taken into account in the preparation of the forecasts.

Capital expenditure forecasts have been planned and prepared using asset management and planning strategies. In particular, for each relevant asset category, the planning and incurring of capital expenditure in accordance with the replacement asset management strategies and network capacity planning strategies, and the resultant scope of works for the 2016-2020 regulatory control period, ensures that Powercor efficiently and prudently achieves the capital expenditure objectives over the period.

A range of source material has been used in developing the forecasts, including asset management plans, and planning policies and guidelines. These various documents are listed in Reset RIN Template 7.1 and are attached to the regulatory proposal. The RIN discusses the relevance of the documents to the regulatory proposal, and in some cases, this appendix discusses where they have been applied in developing the forecasts for each category of capital expenditure.

In addition, economic analysis and/or technical reports have been obtained from consultants to assist in preparing, or reviewing, the forecasts. These reports are attached to the regulatory proposal and are discussed in each relevant category of capital expenditure in this appendix.

Models containing quantitative data that have been used in the preparation of the capital expenditure forecast are attached to this regulatory proposal. The models contain detail of the calculations that have been made to generate data provided in the regulatory templates. It is noted that the base capital expenditure models contain direct cost data only, and escalations and other factors are subsequently overlaid through other models before the final capital expenditure numbers are presented.

The key assumptions underpinning the capital expenditure forecasts are set out in the *Certification of reasonableness of key assumptions* attachment. The reasonableness of the key assumptions that underlie Powercor's expenditure forecasts was certified by the Board of Directors. This certification is provided within the attachment.

Powercor considers that its forecast total capital expenditure is required to achieve the capital expenditure objectives. The way in which the total forecast capital expenditure meets the capital expenditure objectives, criteria and factors in set out in appendix D.

2.2.2 Forecasting outputs

Historical and forecast capital expenditure is contained in the *PAL capex consolidation* model attached complying with the requirements of the Reset RIN.

The model contains Powercor's capital expenditure for each regulatory year between 2006 and 2014 and Powercor's expected capital expenditure for 2015 categorised in the same way as the capital expenditure forecast for the 2016–2020 regulatory control period and separately identifying for each regulatory year between 2006–2015:

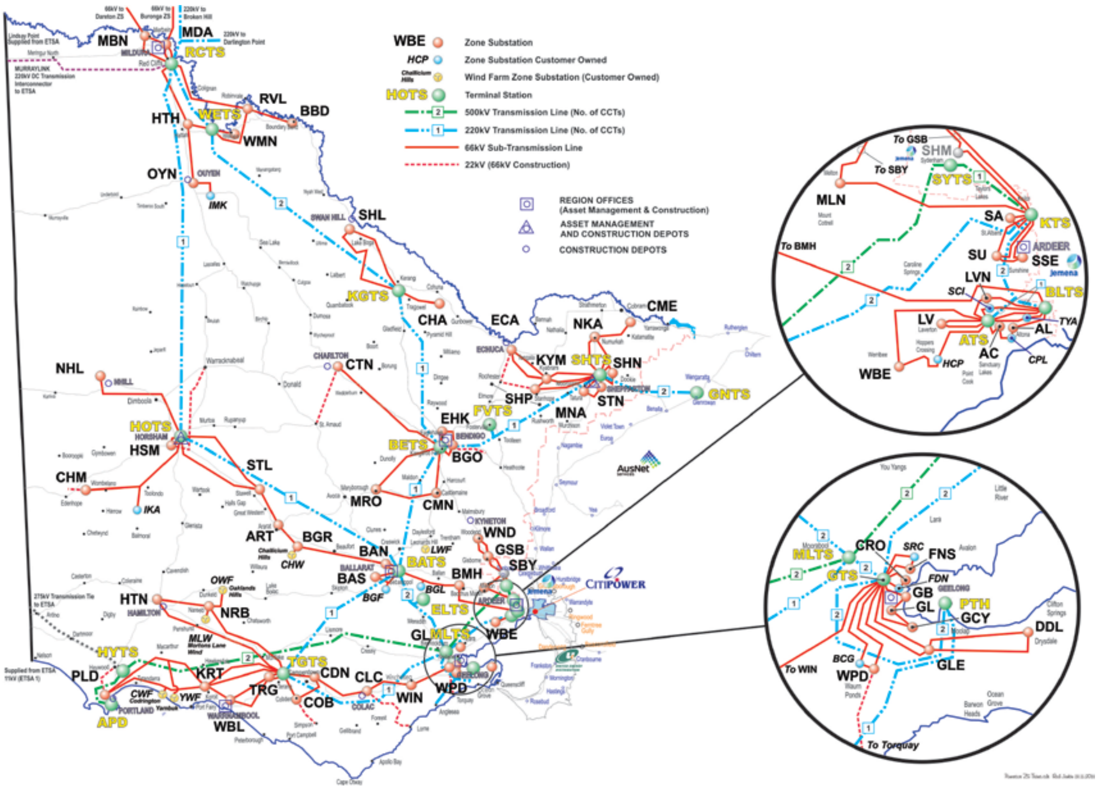
- margins paid or expected to be paid by Powercor in circumstances where those margins are referable to arrangements that do not reflect arm's length terms; and
- expenditure that should have been treated as operating expenditure in accordance with the current capitalisation policy for that regulatory year.

Powercor's *Capitalisation Policy* is attached.

2.2.3 Material assets

The location of Powercor's material assets, in particular zone substations and sub-transmission lines, is shown in figure 2.1.

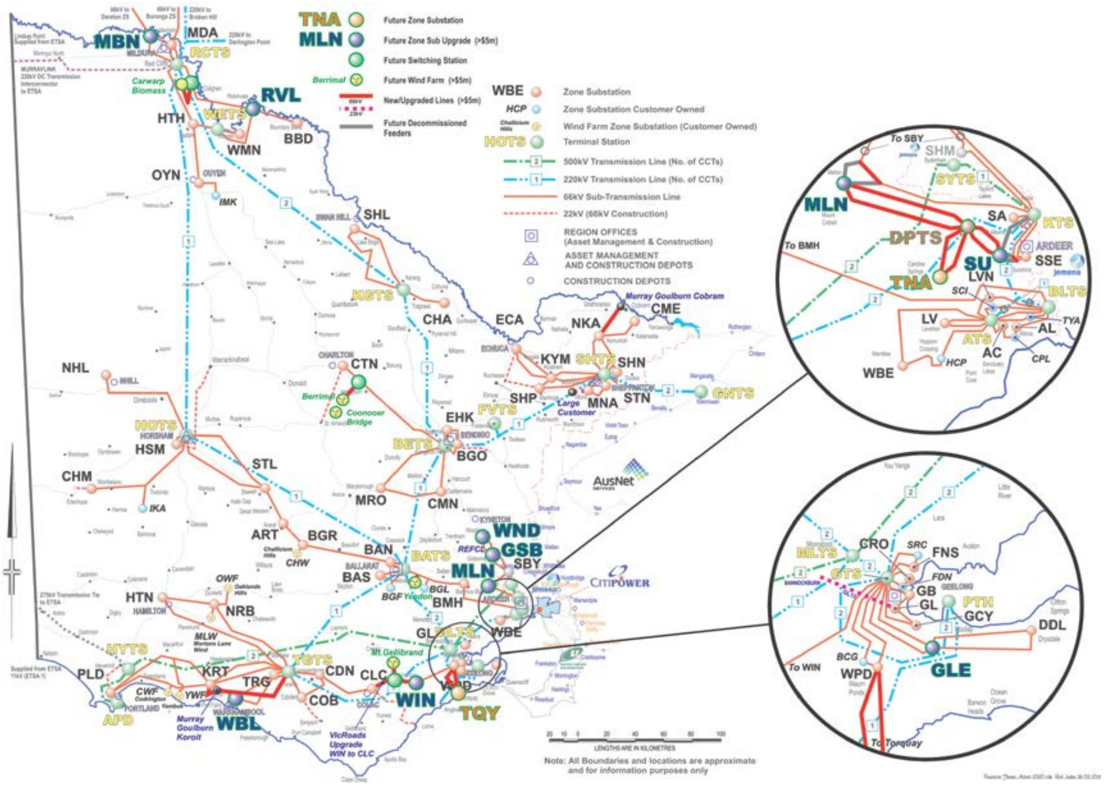
Figure 2.1 Map of Powercor's material assets



Source: Powercor

At the end of the 2016–2020 regulatory control period, the network will have been augmented and new connections added, to meet demand and customer requirements over the period. A map which highlights the expected changes to the network and shows all proposed material assets is shown in figure 2.2 below.

Figure 2.2 Map of Powercor's expected network at the end of 2020



Source: Powercor

The notable additions to the network map include:

- new Truganina (**TNA**) zone substation connected to Deer Park terminal station (**DPTS**), as well as new and rearranged sub-transmission lines associated with DPTS;
- new Torquay (**TQY**) zone substation and associated sub-transmission lines;
- Mt Gellibrand, Berrimal and Coonooer wind farms; and
- other new customer connections with associated new sub-transmission lines.

These projects for new network services or new connections requiring augmentation are described in greater detail in this appendix, together with the anticipated cost of these proposed assets.

2.2.4 Deliverability

A deliverability plan has been developed to ensure that Powercor is able to provide and deliver the necessary works over the 2016–2020 regulatory control period. The deliverability plan will utilise internal labour resources which will be supplemented, as required, by use of external subcontractors. Powercor has established a number of arrangements to ensure that it can access external resources as required, including:

- long term panel contractors including preferred labour electrical and civil works suppliers;
- nine Local Service Agents (**LSA**) located in 13 regional areas; and
- access to agency and limited tenure personnel.

Local Service Agents

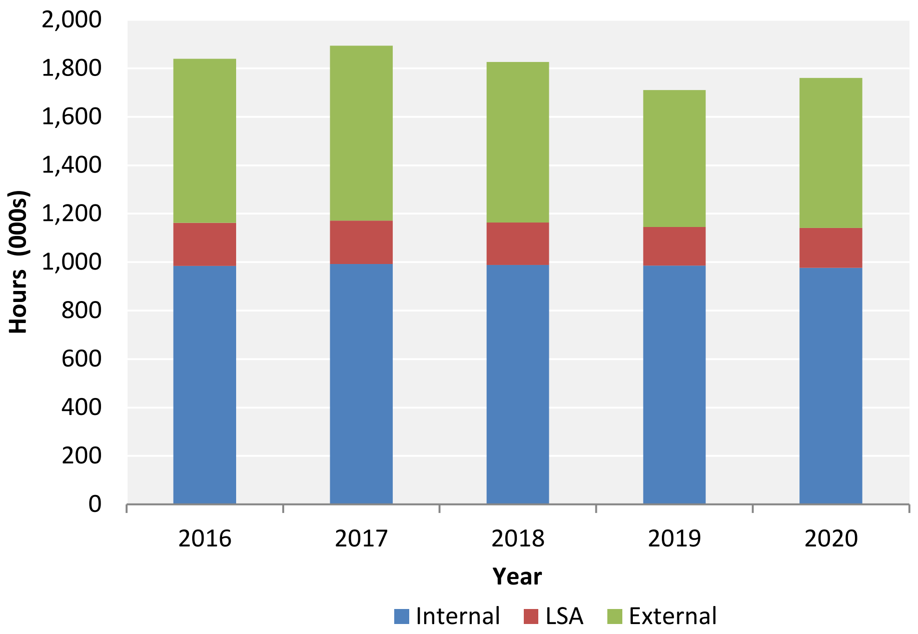
In 1997, Powercor supported a number of employees to setup their own electrical service companies, known as Local Service Agents (**LSA**s). These LSA were then able to apply to provide contracted skilled labour back to Powercor as required.

The LSA program has expanded to 13 locations across Victoria, covering 65 per cent of Powercor's geographical area. The nature of the service offering provided by LSAs has expanded over time to cover construction and maintenance activities including general line workers, glove and barrier line workers, electrical fitters, field and zone substation operating and design and project management.

The mix between internal and external labour resources will be determined by, amongst other things workload volumes, timing and locations; skills and competencies requirements; resource availability; peak period workloads; and labour rates for internal versus external resources.

The proposed deliverability plan for design and field services works, by work hours, is shown in figure 2.3.

Figure 2.3 Deliverability plan by internal and external labour capability



Source: Powercor

LSAs and panel contractors provide a degree of flexibility in allocating resources to meet varying annual workload levels. These flexible arrangements enable Powercor to minimise the costs of engaging external resources to assist in delivering the services that customers require.

Further information on how Powercor optimises its labour resourcing using diverse contracting arrangements is discussed in the appendix B relating to the efficiency of labour costs.

3 Replacement expenditure

Powercor is committed to taking a targeted and cost effective approach to the replacement and refurbishment of its assets. The approach is based on monitoring assets, and taking a risk-management based approach following any condition assessments, only replacing or repairing an asset when it is needed to maintain safety, reliability and/or security of supply.

The condition of the network assets deteriorates as a result of age, environment and other factors. Energy Safe Victoria (**ESV**) has noted the increasing failure rate of Powercor's assets such as pole top structures, fuses, bare conductor and high voltage ties over the current regulatory control period, as a result of the ageing network and despite increasing replacement activity.

This section discusses Powercor's historical and forecast replacement expenditure as well as the approach used in calculating the forecast expenditure.

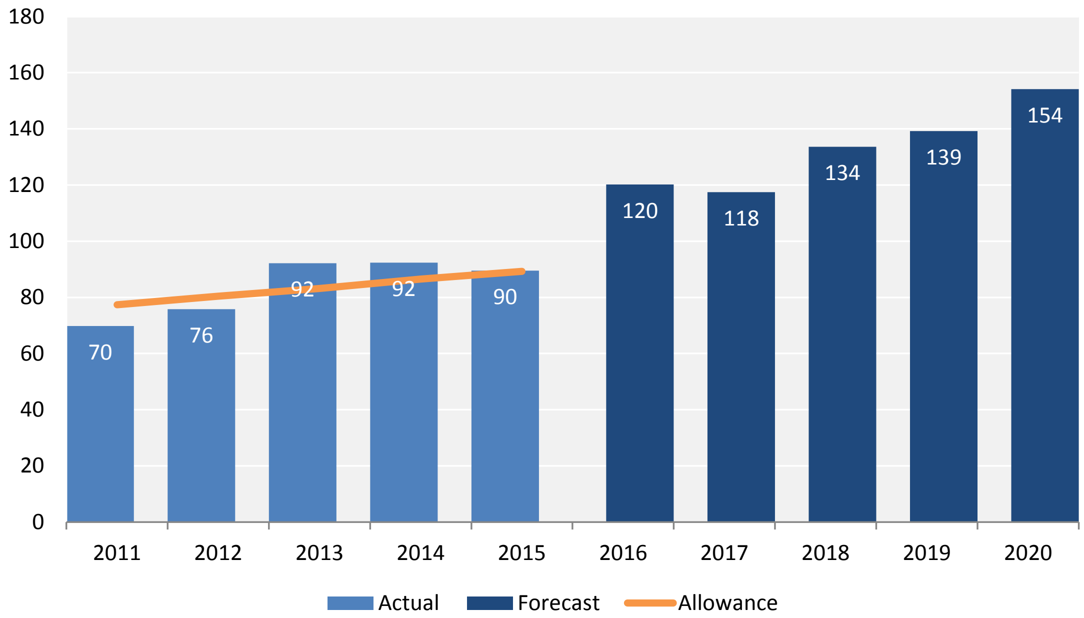
3.1 Overview

Replacement capital expenditure relates to the replacement of an asset with its modern equivalent.

The category also includes routine replacement expenditure which was captured in the separate category of Environment, Safety and Legal (**ESL**) in the 2011–2015 regulatory control period. It includes replacement driven by environmental considerations such as noise abatement, drainage of oil, as well as electrical safety requirements. While ESL was previously a separate category, aside from the specific obligations arising from the Victorian Bushfires Royal Commission (**VBRC**) the historical expenditure has been mapped to replacement category to enable comparisons between periods.

The profile of the actual and forecast expenditure over time is shown in figure 3.1.

Figure 3.1 Replacement direct capital expenditure ($2015, million)



Source: Powercor

The figure 3.1 shows that the profile of the actual replacement expenditure has climbed since 2011, and then levelled since 2013.

The forecast expenditure profile shows a continuation of the year-on-year upward trend in actual expenditure, although the increase is at a slower rate than observed over the 2009 to 2013 period.

The upward trend in actual and forecast expenditure since 2009 is driven by a range of factors, including:

- increasing volume of assets, particularly poles and wires, that were installed in the 1960s where the condition is deteriorating and requiring replacement as they are reaching their end-of-life;
- further works to replace transformers and switchgear in zone substations based upon condition; and
- proactive conductor replacement that commenced in 2011 but was paused given the uncertainty surrounding the requirements for the undergrounding of assets through the VBRC and Powerline Bushfire Safety Taskforce (PBST), and then recommenced in 2014.

These matters are discussed in detail in this chapter.

Powercor has engaged with its stakeholders to understand their views on the need to replace assets to maintain reliability. Around eight out of ten customers indicated that they are generally satisfied with the current level of reliability in the online survey.[5] Residential customers have indicated that they want the reliability levels to be kept the same or improved, but not reduced.[6] Similarly, small/medium enterprise (**SME**) customers indicated no interest in reduced reliability for a small price reduction due to the large expense associated business downtime.7

They should keep doing what they are doing, maybe a little more but definitely no less."

I need power to run my business, it's that simple. If there's no power, the work stops."

In response to the Directions and Priorities paper, the Wannon Region Dairy Branch of the United Dairyfarmers of Victoria noted that:[8]

> *…we are very insistent that work be done to update older, unreliable infrastructure, particular the old SWER (Single Wire Earth Return) lines, & maintain all infrastructure to improve reliability of supply. Where outages occur… the consequences for the dairyfarmer can be very serious.*

This impact of unreliability was further expanded upon by the United Dairyfarmers of Victoria, which stated that:[9]

> *Farmers risk losing thousands of dollars' worth of milk when power failures or brownouts affect heating and cooling systems that ensure milk meets food safety standards. Insecure*

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[5] Colmar Brunton Research, *Powercor Stakeholder Engagement Research Online Customer Survey Results*, 18 July 2014, p. 42.

[6] Colmar Brunton Research, Powercor Stakeholder Engagement Research Report – Residential customer focus groups and SME customer interviews, 1 May 2014, pp. 26.

[7] Colmar Brunton Research, *Powercor Stakeholder Engagement Research Report – Residential customer focus groups and SME customer interviews*, 1 May 2014, pp. 27.

[8] Wannon Region Dairy Branch, *Response to Powercor/ CitiPower Directions and Priorities consultation paper*, 30 October 2014, p. 2.

[9] United Dairyfarmers of Victoria, CitiPower and Powercor Australia Directions and Priorities Consultation Paper, 5 November 2014, p. 3. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/21.UDV-5-November-2014.pdf.

> *power supplies can affect milking machines, leading to animal welfare issues such as mastitis. Due to their remote location farmers are invariably last to be reconnected after power outages.*
>
> *This unreliability of supply in the regional areas where most factories are located in also a concern as power interruptions result in significant costs to production continuity, supply and food safety. Unreliable power supplies also affect farmers, who can lose milk and subsequently income if, for example, milk cooling is not operational.*

Powercor's large customers expect reliable supply of electricity, to ensure that their business can operate with certainty and at full capacity. Customers expect us to ensure that ageing electricity assets and those exposed to weather, fire and motor vehicle contact are updated as and when required.[10]

Customers expect Powercor to continue to provide a reliable supply for a reasonable price, with close attention to safety and regular maintenance.[11] Where assets need to be replaced, Powercor will take into account technological advancements to ensure use of modern assets that take into account future network needs.

3.2 Background information

This section describes the asset management process and Powercor's methodology for forecasting replacement capital expenditure.

Replacement capital expenditure is primarily driven by the condition of the asset. That is, the asset is replaced when its condition deteriorates to a level that triggers its replacement in accordance with the internal asset management policies.

There are times, however, when other factors trigger the need for the asset to be replaced, such as technical obsolescence, environmental considerations or proactive programs to replace assets of a certain class to address safety related matters.

The need for asset replacement may also be considered alongside forecast changes in load growth for an area. Where Powercor identifies a network constraint and replaces an asset to address the asset condition as well as increase the network capacity, then the expenditure would be categorised as augmentation. In contrast, where the replacement of the asset results in incidental augmentation, for example where like-for-like replacement may be more costly than replacement with a higher-capacity asset, then the expenditure would be categorised as replacement. That is, the identified need that drives the expenditure will determine the categorisation of the expenditure.

3.2.1 Forecasting methodology

This section sets out the principles and processes underpinning Powercor's two asset management methodologies, and the method for forecasting replacement capital expenditure using those methodologies.

10 Colmar Brunton Research, *Powercor Stakeholder Engagement Research – Top 200 customers in –depth interviews*, 22 July 2014, p. 21.

11 Colmar Brunton Research, *Powercor Stakeholder Engagement Research Report – Residential customer focus groups and SME customer interviews*, 1 May 2014, pp. 22-23.

The Asset Management Framework describes the principles of asset management that apply to all of Powercor's network assets, and requires that all of the assets are maintained, refurbished or replaced in accordance with the asset management plans.[12]

The asset management framework aligns with the principles of PAS 55, which is the British Standards Institution's publicly available specification for the optimised management of physical assets.[13]

Powercor's assets are subject to relevant condition assessment methods through planned inspection and monitoring programs. These programs have been developed taking into account regulatory obligations, industry knowledge as well as proven and established asset management methodologies.

Powercor applies the following asset management methodologies to its network assets:

- reliability and safety based regime—this methodology is based on the principles of Reliability-Centred Maintenance (**RCM**) together with regulatory obligations that are built into the asset management procedures. It is applied to routine replacement expenditure for high-volume plant and equipment such as poles, pole top-equipment, cross-arms, insulators and batteries. The approach has regard for the asset age, condition and operating environment; and
- Condition Based Risk Management (**CBRM**)—this methodology is applied to assess the condition of assets, including the risk of the deterioration, of major items of plant, which involve significant and lumpy expenditure. This includes assets such as zone substation transformers and switchgear.

These are discussed in more detail in the sections below.

'Poles and wires'

The reliability and safety based regime, based on RCM principles and regulatory obligations, is applied to high-volume plant and equipment such as poles, cross-arms, conductors, protection relays as well as other assets poles and wires.

The process involves regular inspections of the assets, where defects are identified. A remedy is then applied to address the defect, which may consist of a maintenance solution or replacement of the asset.

Asset management policy

The asset management regime consists of RCM principles as well as relevant regulation obligations, as shown in figure 3.2.

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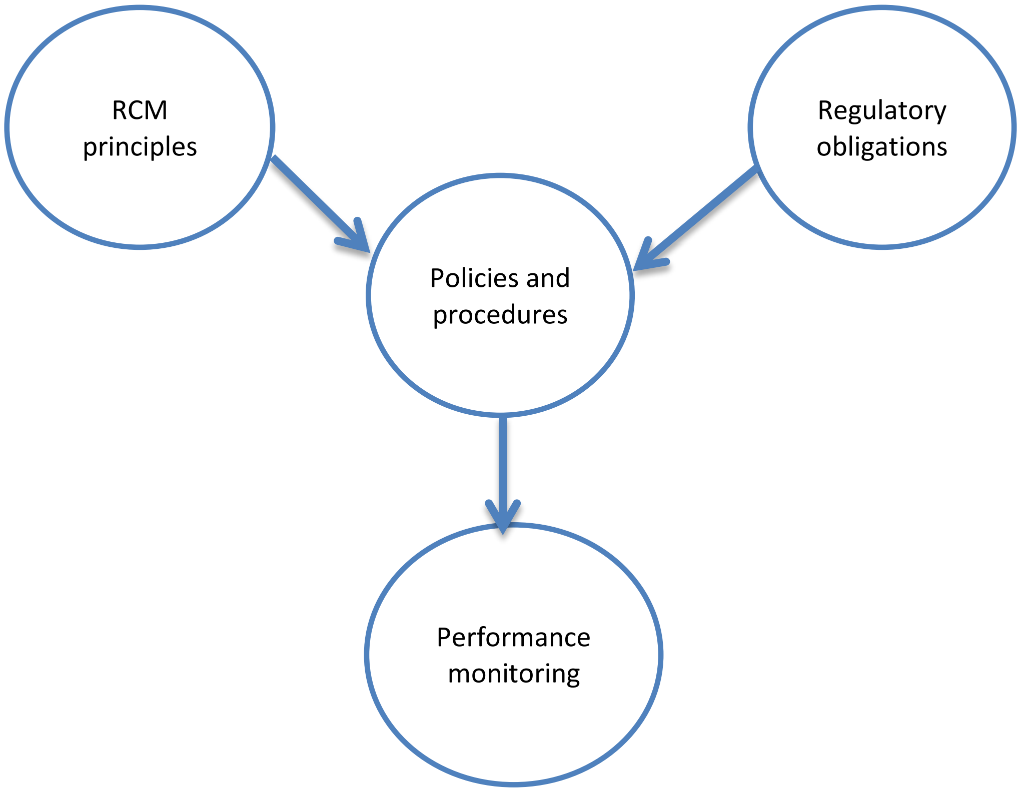
12 Powercor, *Asset Management Framework*, 2015.

13 Available from http://www.bsigroup.com/en-AU/PAS-55-Asset-Management/

Figure 3.2 Elements of the reliability and safety based maintenance regime



Source: Powercor

At a high level, the RCM process is used to determine what must be done to ensure that any physical asset continues to operate to its intended performance.

The RCM process identifies each possible way in which a defect may occur in an asset, and the root cause of that defect. For each different type of defect, the possible impact on the safety, operations and other equipment in the network is assessed. Consequently, a maintenance strategy to address each type of defect is determined.

Where a defect is identified in an asset, then the maintenance strategy to address that defect is implemented. This may involve replacement of the asset, or maintenance measures to prolong the life of the asset, such as pole staking.

The RCM process can be summarised by a series of steps, as follows (figure 3.3).

Figure 3.3 Steps in the RCM process

1. Select functions and performance standard of asset	• ensure the asset continues to do what its users want it to do • consider primary functions and secondary functions of asset
2. Identify function failures	• identify the ways in which the asset may fail to fulfil its functions
3. What causes each functional failure	• identify all of the events which are reasonably likely to cause each failed state • includes failures which have occured on the same or similar equipment; are prevented by existing maintainence procedures; and those which possibly may occur
4. What happens when failure occurs	• list all failure effects that describe what happens when a failure mode occurs, including supporting evidence • e.g. what is the evidence that a failure has occured, how does it pose a threat to safety or the environment
5. How does the failure matter	• consequences of failure of a hidden function, where failure will not become evident to operators under normal circumstances • consequence of failure of an evident function in terms of the impact on safety, environment, operational and non-operational matters
6. How to prevent or predict each failure	• identify the most appropriate maintenance strategy for each failure mode, which is also technically and economically feasible • where it is not possible to identify a pro-active task, select default actions such as proof testing, re-design or run to failure
7. Regularly review process	• once maintenance recommendations are put into practice, these are routinely reviewed and renewed as additional information is found

Source: Powercor

RCM analysis is undertaken by taking into account the equipment manufacturer's recommendations, the physical and electrical environment in which the asset is installed, fault and performance data, test data, condition data, duty cycles as well as many years of field-based experience.

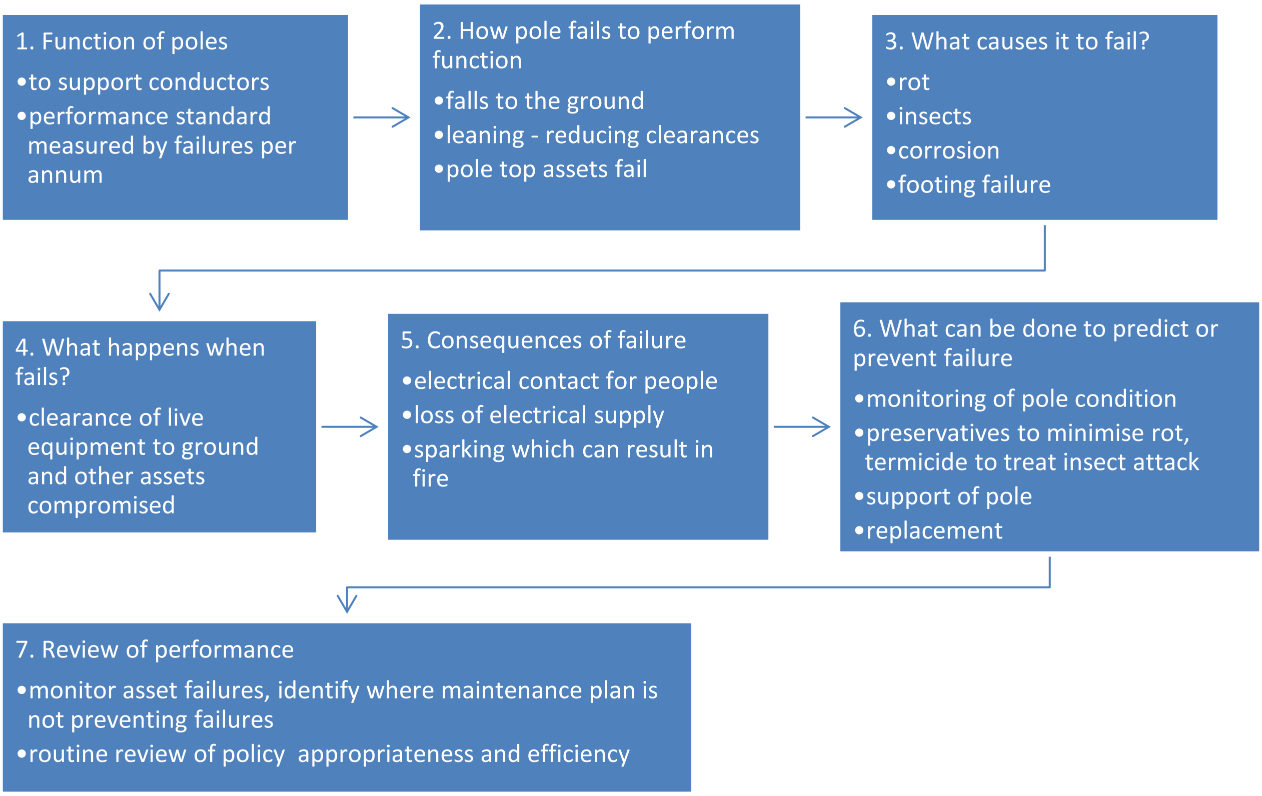
The combination of general maintenance requirements and the specific requirements based on the environments in which the assets operate may result in varying maintenance and condition monitoring regimes for the same type of asset. Tests and inspections are undertaken using tools such as thermal imagery, visual inspections, and invasive pole testing to assess asset condition.

Together with the relevant regulatory obligations, which for example may set out the inspection cycle, the resulting inspection and maintenance regimes form a comprehensive asset management system, which is documented through Technical Standards, asset management plans, maintenance policies, asset inspection manual and work instructions, which are embedded into Powercor's corporate asset management enterprise system.

Maintenance policies are monitored through asset failure analysis and routinely reviewed to ensure the objectives of the maintenance regime are being achieved in terms of cost and asset performance. All maintenance and condition monitoring strategies are reviewed as a minimum once every five years.

A simplified example of how the RCM principles are applied to poles is shown in figure 3.4. Powercor undertakes regular inspection of poles for diagnostic testing and monitoring of the assets to determine their relative performance and remaining life.

Figure 3.4 Example of how RCM principles are applied to poles



Source: Powercor

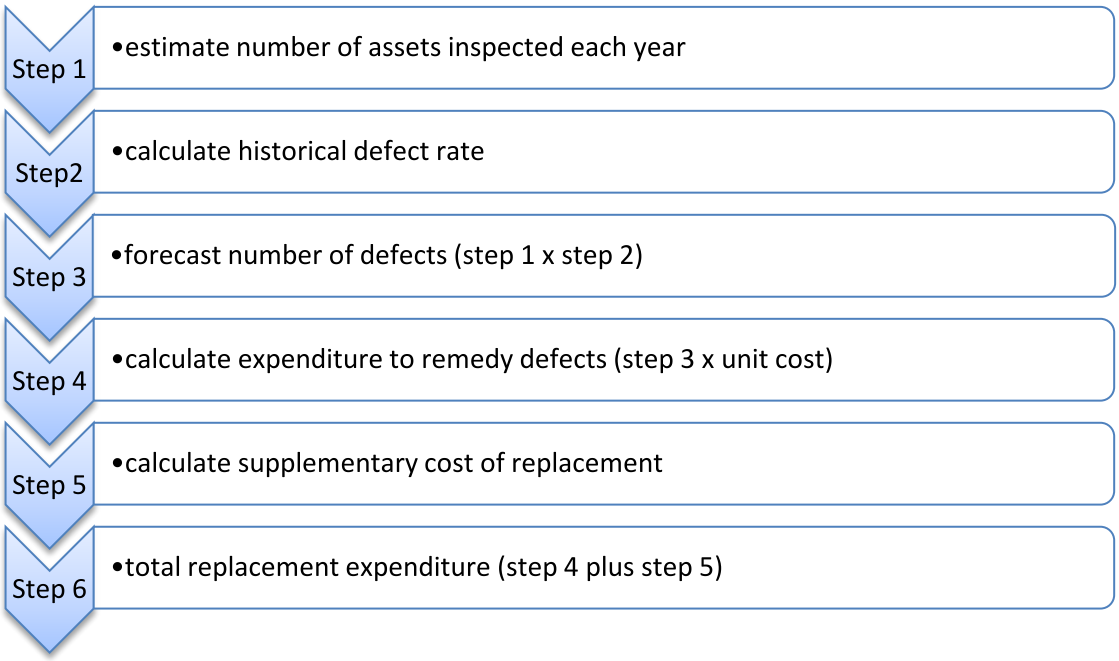
The performance of poles is monitored to highlight where the developed maintenance plan is not preventing failures. This may trigger a review of the RCM methodology, while taking into account any relevant regulatory obligations.

Routine review of the policy considers its appropriateness and efficiency, taking into account cost, industry developments, changed environmental conditions as well as failure and defect rates. That is, the review considers whether the policy is achieving its objectives.

Forecasting costs for 'poles and wires'

In forecasting the expenditure for 'poles and wires', the following process has been used:

Figure 3.5 Process for forecasting expenditure for poles and wires



Source: Powercor

To understand how this process works in practice, an example is provided below of the forecasting methodology as it is applied to poles.

Step 1: to estimate the number of poles that will be inspected each year, the process primarily relies upon the observation and classification of defects through the routine inspections of poles and related assets. The number of poles inspected each year varies and thus the volume of defects identified.

Step 2: calculate the historical defect rate for each class of assets. In forecasting the number of replacements to be carried out in the 2016–2020 regulatory control period, Powercor considers the annual and trend rates for various defect types on the assets.

Powercor records the number of defects for each class of asset. Based on this information, Powercor has been able to calculate the defect rate for pole replacement as a proportion of the overall asset base.[14]

Table 3.1 Pole defect rates

	2009	2010	2011	2012	2013	2104
Defect rate	0.0018	0.0017	0.0026	0.0026	0.0029	0.0031

Source: Powercor

Similarly, the defect rate for cross-arms as a proportion of assets inspected has been increasing, as shown in table 3.2.

[14] Total asset base has been used as the denominator, rather than assets inspected, to provide a consistent historical trend given the change in the asset inspection cycle during the current regulatory control period.

Table 3.2 Cross-arm defect rate

	2009	2010	2011	2012	2013	2104
Defect rate	0.0202	0.0249	0.0379	0.0383	0.0436	0.0451

Source: Powercor

Step 3: to calculate the forecast number of defects, the number of defects likely to be observed in each year is calculated by multiplying the number of poles to be inspected in each year (step 1) with the defect rate (step 2).

Step 4: to calculate the expenditure associated with remedying the defects, the expenditure for replacing assets is calculated by multiplying the forecast number of defects (step 3) by the average unit cost of remedying the defect.

As replacement costs are captured at a project level, each of which contains multiple individual items of work to be completed, the average unit costs have been calculated by apportioning the total expenditure on replacement to these assets across the units of work recorded and completed. This is further discussed below.

Step 5: to calculate supplementary costs of replacement, it is noted that the unit costs used in step 4, above, do not capture all replacement costs associated with the works. For example, the costs do not capture earthing issues or installation of bird covers during the maintenance program, or the proactive conductor replacement program.

Step 6: to calculate total replacement expenditure for RCM, this is calculated as the sum of the expenditure to remedy defects (step 4) plus the supplementary costs associated with the works (step 5).

Unit rates for assets managed under reliability and safety based regime

Powercor does not collect unit cost information at a disaggregated asset level. Rather, Powercor captures total costs for a program of work, and then allocates the costs to each function code. This is because it is more efficient for Powercor to undertake several jobs on a single asset or several assets when dispatched to the field, rather than completing an individual asset job and returning to the depot. This is discussed in the box below.

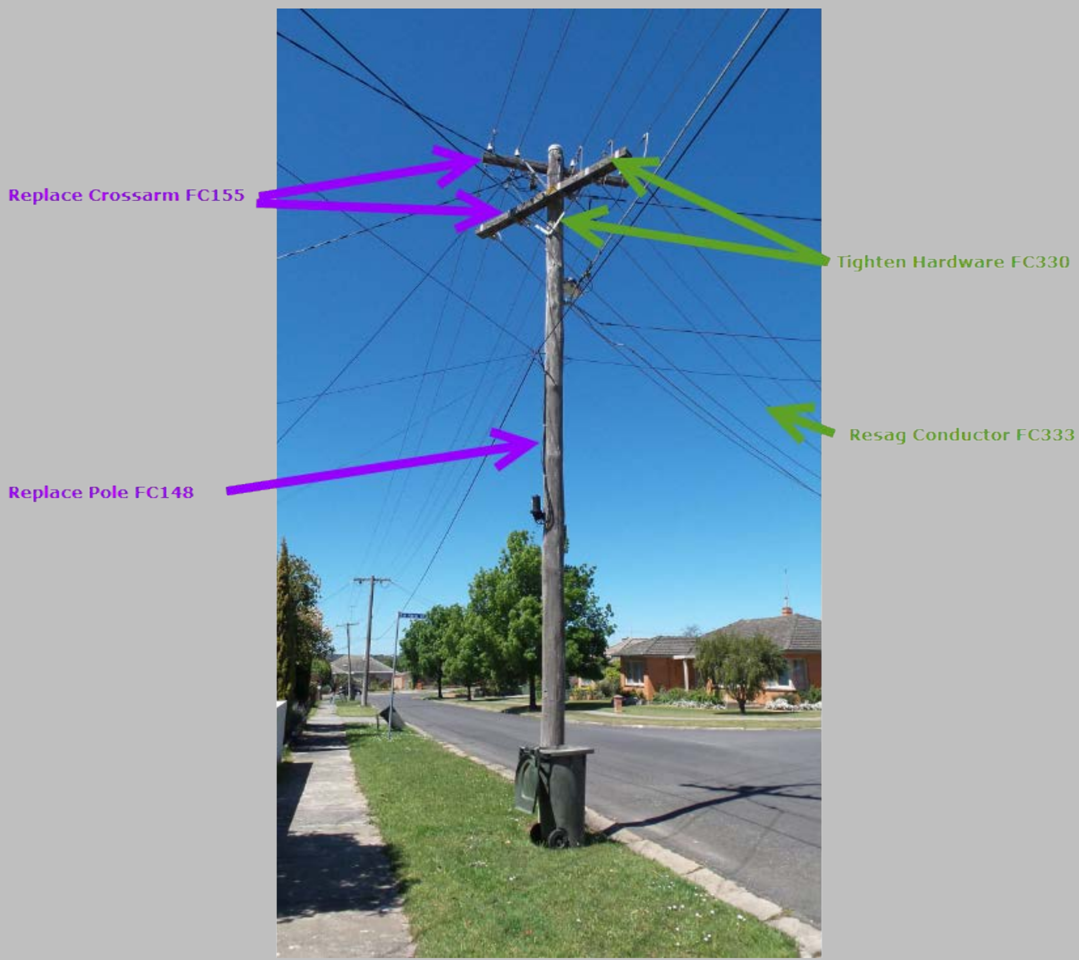
The average replacement cost per function code is calculated by dividing the total costs allocated to the function code in the year by the total defect volumes reported for the function code in the year.

This average replacement rate per function code is used in the expenditure forecast. The average replacement rate is calculated as the average over the period from 2011 to 2014. This average replacement cost by function code is multiplied by the expected replacement rate for a category of assets each year, to determine the expenditure forecast. That is, the costs are based on actual historical costs for similar projects, where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

Undertaking several jobs on a single asset

When a crew visits an asset location to undertake works, they rarely undertake a single activity. As shown in the picture below, the crew may replace the pole and the cross-arm, and at the same time they may tighten the king bolt, resag the conductor, tighten the cross-arm strap and replacement the insulator.

Figure 3.6 Mix of works undertaken at a single location



Source: Powercor

It is clearly more practical and efficient for the raft of works to be undertaken in a single visit, rather than return visits for each activity.

Transformers and switchgear

Condition Based Risk Management (**CBRM**) is a structured process that combines asset information, engineering knowledge and practical experience to define future condition, performance and risk for network assets.

Powercor applies the CBRM methodology to certain plant-based asset classes, namely transformers and circuit breakers.

Asset management

The CBRM methodology has been progressively developed over a number of years and has been successfully applied many times, helping distributors around the world to deliver effective asset related risk management. The CBRM process is extensively used by distributors in the United Kingdom, as well as other distributors in Australia such as SA Power Networks. The CBRM methodology that Powercor uses has been developed by EA Technology.

The methodology draws upon Powercor's knowledge and experience relating to degradation, failure, condition assessment, performance and influence of environment, duty, operational policy and specification of network assets. It is used to define current and future condition and performance of the assets.

The CBRM process can be summarised by a series of sequential steps, as follows:

Table 3.3 Steps in the CBRM process

Step	Description
1	**Define asset condition** Health indices are derived for individual assets within different asset groups. Health indices are described on a scale of 0 to 10, where 0 indicates the best condition and 10 the worst.
2	**Link current condition to performance** Health indices are calibrated against relative PoF. The HI/PoF relationship for an asset group is determined by matching the HI profile with the relevant observed failure rates.
3	**Estimate future condition and performance** Knowledge of degradation processes is used to trend health indices over time. This ageing rate for an individual asset is dependent on its initial HI and operating conditions. Future failure rates can then be calculated from aged HI profiles and the previously defined HI/PoF relationship.
4	**Evaluation of potential interventions in terms of PoF and failure rates** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled and the future HI profiles and failure rates reviewed accordingly.
5	**Define and weight consequences of failure (CoF)** A consistent framework is defined and populated in order to evaluate consequences in significant categories such as network performance, safety, financial, environmental, etc. The consequence categories are weighted to relate them to a common unit.
6	**Build risk model** For an individual asset, its probability and consequence of failure are combined to calculate risk. The total risk associated with an asset group is then obtained by summing the risk of the individual assets.
7	**Evaluate potential interventions in terms of risk** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled to quantify the potential risk profile associated with different strategies.
8	**Review and refine information and process** Building and managing a risk based process based on asset specific information is not a one-off process. The initial application will deliver results based on available information and crucially, identify opportunities for ongoing improvement that can be used to build an improved asset information framework.

In terms of the steps in the process:

- steps 1 to 4 essentially relate to condition and performance and provide a systematic process to identify and predict end-of-life. Future expenditure plans can then be linked to probability of failure and failure rates;

- steps 5 to 7 deal with consequence of failure and asset criticality that are combined with PoF values to enable definition and quantification of risk; and
- step 8 is a recognition that building and operating a risk-based process using asset specific information is not a one-off exercise.

Each year, Powercor updates the data in its CBRM model, which is contained in a MS Excel spreadsheet. Powercor reviews the outputs of the CBRM which indicate the various replacement projects required, and identifies the projects that deliver the greatest risk reduction. The latter projects are determined by calculating the difference between the risk in a future year if the asset is not replaced and the risk that would result if the plant is replaced, and then assessing the various options to deliver the risk reduction.

While the CBRM methodology identifies a proposed year for the replacement of an asset, the project is then reviewed in conjunction with other augmentation and development plans in order to identify opportunities for synergies, such that the replacement schedule can coincide with other major works. The project is then captured within a future works plan.

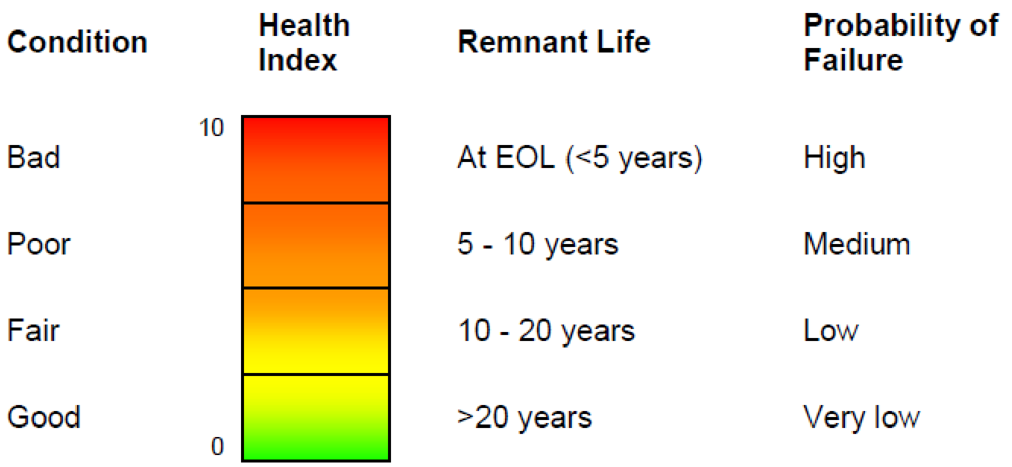
Prior to the project commencing, it is taken to the Capital Investment Committee (**CIC**) for a detailed review and to ensure that capital expenditure is targeted to deliver optimum outcomes for shareholders, customers, the community and employees.

Further detail regarding the key parameters in the CBRM model is provided below.

Health indices to determine asset condition

The first stage in the CBRM process is to derive a numeric representation of the condition of each asset in the form of a HI. Essentially, the HI of an asset is a means of combining information that relates to its age, environment, duty, and specific condition and performance information (such as original specification, manufacturer) to give a comparable measure of condition for individual assets in terms of proximity to end of life (**EOL**) and probability of failure. The concept is illustrated schematically in figure 3.7.

Figure 3.7 Concept of Health Indices



Source: Powercor

The HI represents the extent of degradation as follows:

- low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal ageing, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the PoF remains very low and the condition and PoF would not be expected to change significantly for some time;

- medium values of HI, in the range 4 to 7, represent significant deterioration, degradation processes starting to move from normal ageing to processes that potentially threaten failure. In this condition, the PoF, although still low, is just starting to rise and the rate of further degradation is increasing; and
- high values of HI (>7) represent serious deterioration, advanced degradation processes now reaching the point that they actually threaten failure. In this condition the PoF is significantly raised and the rate of further degradation will be relatively rapid.

The detail of the HI formulation is different for each asset group, reflecting the different information and the different types of degradation processes. That said, there is an underlying structure for all asset groups as outlined below.

- For a specific asset, an initial age related HI is calculated using knowledge and experience of its performance and expected lifetime, taking account of factors such as original specification, manufacturer, operational experience and operating conditions (duty, proximity to coast, etc).
- Where condition information relating to specific degradation processes can be used to identify potential end of life conditions (e.g. oil test results for transformers), a separate factor is derived for each degradation process, calibrated by linking a defined condition to a specific HI value. This gives rise to a number of multipliers, one for each potential end of life condition. These are then combined to give a 'combined condition factor'.
- Additional information that is indicative of condition but cannot be directly related to specific degradation processes is used to create additional 'factors' that modify the basic age related HI described above. Examples include factors relating to fault/defect history and reliability issues associated with specific equipment types (e.g. different manufacturers).

Calculation of failure rates to assess asset performance

The relationship between the HI and probability of failure for any asset group is determined by matching the HI profile with the recent failure rate. Powercor uses three condition failure modes according to the following broad definitions:

(i) Minor-an incident resulting in no loss of supply; e.g. a stuck mechanism on a trip test;

(ii) Disruptive-an incident resulting in loss of supply where the asset can be repaired; and

(iii) Catastrophic-the non-repairable failure of an asset resulting in loss of supply and possible damage to adjacent assets.

Non-condition failures, e.g. those caused by external factors such as weather or third party damage can also be included in the CBRM model. However, Powercor has set the number of non-condition failures in the model to zero such that only condition related failures are considered.

The failure rates in the CBRM have been updated since the AER’s 2010 Distribution Determination where the AER criticised the then use of international failure rates within the model on the basis that the failure rates were inconsistent with Powercor’s own historical data.[15]

[15] AER, Victorian Distribution Determinations – Final Decision, Appendix P, pp. 613-614.

In 2012, Powercor reviewed its failure rates and calibrations. Failure rates in each of the three condition failure modes have been calculated by:

- obtaining the average of the number of observed failures over the previous five year period using data from the maintenance management system to estimate the number of failures per year; and
- dividing the average number of observed failures per category (as above) by the population of assets.

Powercor has not experienced catastrophic failure rates for 66kV circuit breakers and switchgear and has thus assumed that, on average, the number of catastrophic failure rates would be around 10 per cent of the number of disruptive failures. This is considered to be a conservative assumption as it is lower than failure rates in published international studies.

Table 3.4 Powercor failure rates used in CBRM

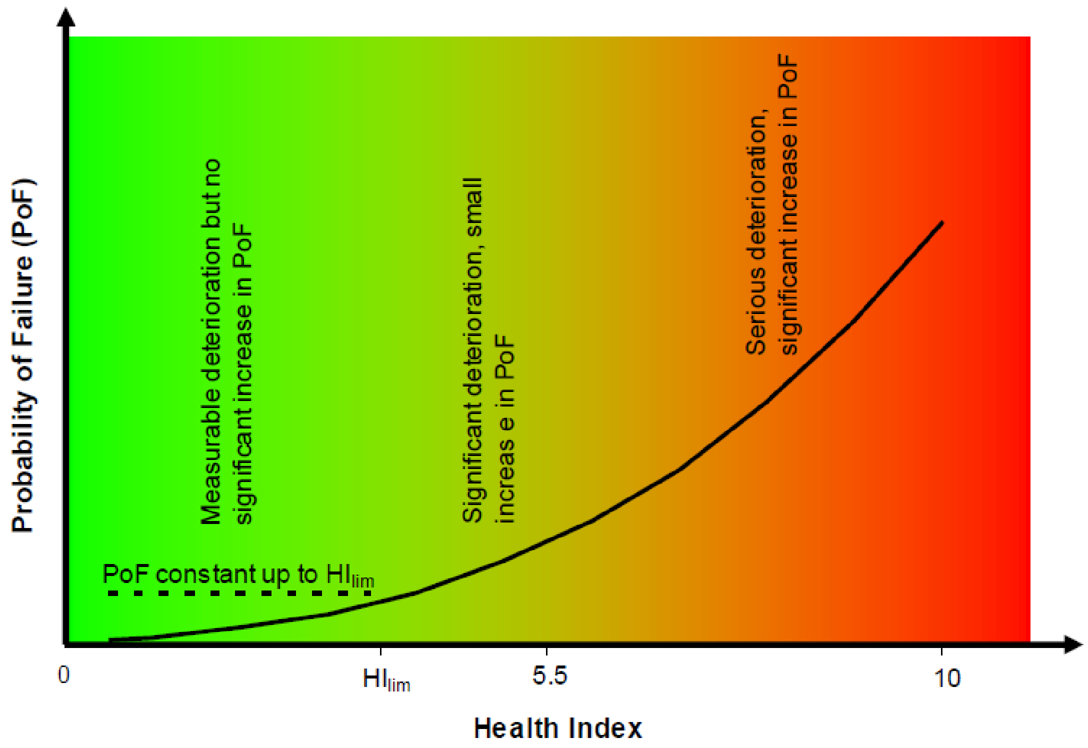
	Transformers		66kV circuit breakers		HV switchgear	
Failure Mode	No. failures per year	Failure rate (no. per asset – year)	No. failures per year	Failure rate (no. per asset – year)	No. failures per year	Failure rate (no. per asset – year)
Minor	92	0.6216	30.8	0.1665	46.2	0.0692
Disruptive	0.4	0.0027	0.2	0.0011	0.2	0.0003
Catastrophic	0.074	0.0005	0.02	0.0001	0.02	0.00003

Source: Powercor

The failure rate is calculated from the number of failures per year and divided by the number of assets. There are 148 transformers, 185 66kV circuit breakers and 668 HV switchgear assets used in the calculation.

The relationship between the HI and condition-related probability of failure for any asset group is shown schematically (solid line) in figure 3.8.

Figure 3.8 Relationship between Health Index and Probability of Failure



Source: Powercor

The relationship is not linear. An asset can accommodate significant degradation with very little effect on the risk of failure. Conversely, once the degradation becomes significant or widespread, the risk of failure rapidly increases. The CBRM model uses a third-order polynomial to define the relationship between the HI and the PoF, which takes into account the HI above the limit value denoted as HI_{lim} in the figure.

This calculation enables Powercor to estimate the HI that would result in 2020 if it did not undertake intervention works to reduce the risk of failure, such as through replacement or refurbishment works.

Consequence of failure to identify risk

The CBRM assesses four categories of consequences of failure and the units of measurement to quantify the impact, including:

- network performance;
- safety;
- financial (e.g. cost of replacement); and
- environmental impact.

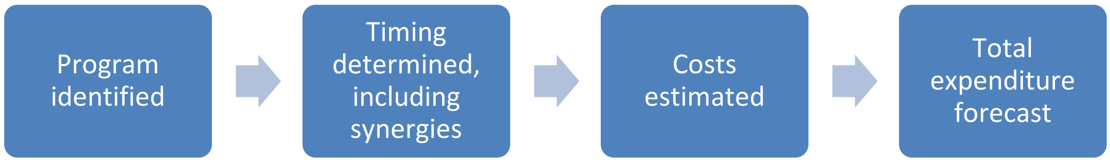
Powercor quantifies the average consequences using actual data of faults and failures from the last five to ten years, where possible. The environmental consequences are intended to reflect the value that Powercor places on the various environmental impacts, rather than the cost of clean-up. Generally, the environmental consequence for the failure of a network asset is small, and is unlikely to be the major driver for investment. The possible exceptions to this are oil-filled switchgear and power transformers, where the environmental risk associated with the oil loss makes a significant contribution to the overall risk.

The CBRM output includes a list of the 30 highest ranking assets based on the 'future year delta risk', i.e. the difference between the risk in a future year if the asset is not replaced and the risk that would result if the plant is replaced. Powercor assesses the various options to deliver the risk reduction for these projects. In addition, Powercor considers replacement of other assets where there are other drivers or needs for the replacement.

Forecasting costs for transformers and switchgear

The process to forecast assets using the CBRM methodology is set out in figure 3.9.

Figure 3.9 Process for forecasting expenditure for larger assets



Source: Powercor

The programs are identified through the output of the CBRM process, together with reported maintenance defects of associated equipment, or through the safety-related asset management policies.

The timing of each program is considered in relation to the condition of the asset and the risk associated with the PoF, or in conjunction with other asset projects such as a planned augmentation or customer connection.

Cost estimates have been obtained from a supplier for each of the material replacement projects for transformers and switchgear. For other projects, the cost estimates have been derived from historical project costs for similar projects, where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

Unit rates

Although Powercor is required to provide unit rates for the replacement or refurbishment of transformers and switchgear, they have not been used to forecast expenditure given the unique characteristics of each project, such as the location and installation.

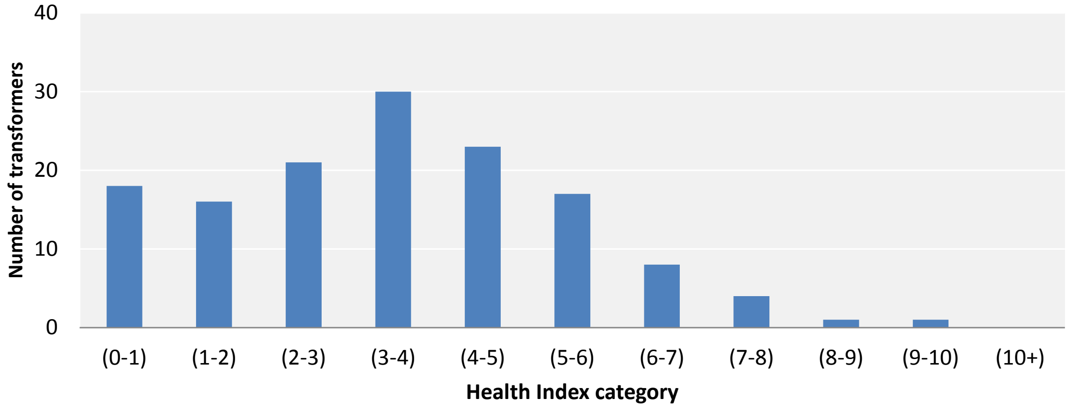
Subject matter experts have verified the reasonableness of the costs based on their knowledge and experience.

Checking the appropriateness of the forecasts using top-down measures

The CBRM process uses the HI of an asset in its current state, and also projects the HI that would result if intervention works were not undertaken, i.e. current and future states.

The HI profile across all assets can be used as a visual tool to understand at a high level the condition of categories of major plant assets, at a point in time. The HI profile of Powercor's transformers in zone substations at the start of the 2016–2020 regulatory control period is shown in figure 3.10.

Figure 3.10 Forecast health index of transformers at zone substations at the start of 2016



Source: Powercor

As noted above, the HI is presented in a range from 0 to 10, where 0 is a new asset and 10 represents end of life.

Powercor focuses on those assets with a HI of seven or above. This represents the stage where planning for replacement is required as the asset is showing signs of end of life and the probability of failure is increasing. As shown in figure 3.10, at the start of the 2016–2020 regulatory control period, Powercor will have six transformers in zone substations with a HI of seven or above, and that includes the units at the Sunshine, Terang and Winchelsea zone substations.

In order to check that the expenditure forecasts are reasonable, sustainable and enable Powercor to prudently and efficiently manage its ageing and deteriorating large assets using current strategies, maintenance policies and operating practices, the CBRM models are used to generate HI profile predictions for future years.

The profiles are compared using a 'do nothing' approach against the forecast replacement (and network reconfiguration) strategies to ensure that, over the forecast period, the HI profile for the total transformer fleet is appropriately managed. A HI profile similar at the end of the forecast period to the current profile infers that:

- no changes to asset management processes are required over the forecast period;
- no backlog of pending replacements at the end of the forecast period; and
- no over-replacement is forecast.

If the HI profile increases over the forecast period, then it may suggest that a step up in expenditure is required.

Other items of plant and equipment

Condition-based monitoring is not possible for all types of plant and equipment. Some plant and equipment rely upon condition-based inspection regimes, similar to poles and wires. For other plant and equipment where condition-based monitoring or assessments cannot be carried out, then other factors may be relied upon to determine the requirement for replacement of the assets. For example:

- earthing cables are replaced following an inspection and/or test of their condition;

- regulators are replaced based on age, with a dedicated program to remove obsolete regulators which no longer have manufacturer support and spares are no longer available;
- surge arrestors are replaced after they operate, otherwise they are replaced upon age or when there is a change in the plant or configuration of the zone substation;
- indoor combination switches in distribution substations are replaced based on age together with deliverability and risk, given that neither the condition nor performance can readily be measured;
- underground cables are replaced based on performance, given that there is no effective technically viable condition monitoring available on a network level to determine replacement; and
- property is generally replaced based upon condition, such as visible defects in cable ducts, roofs, fences and buildings. Fences may also be replaced following a change in the security requirements for a particular zone substation or other network asset.

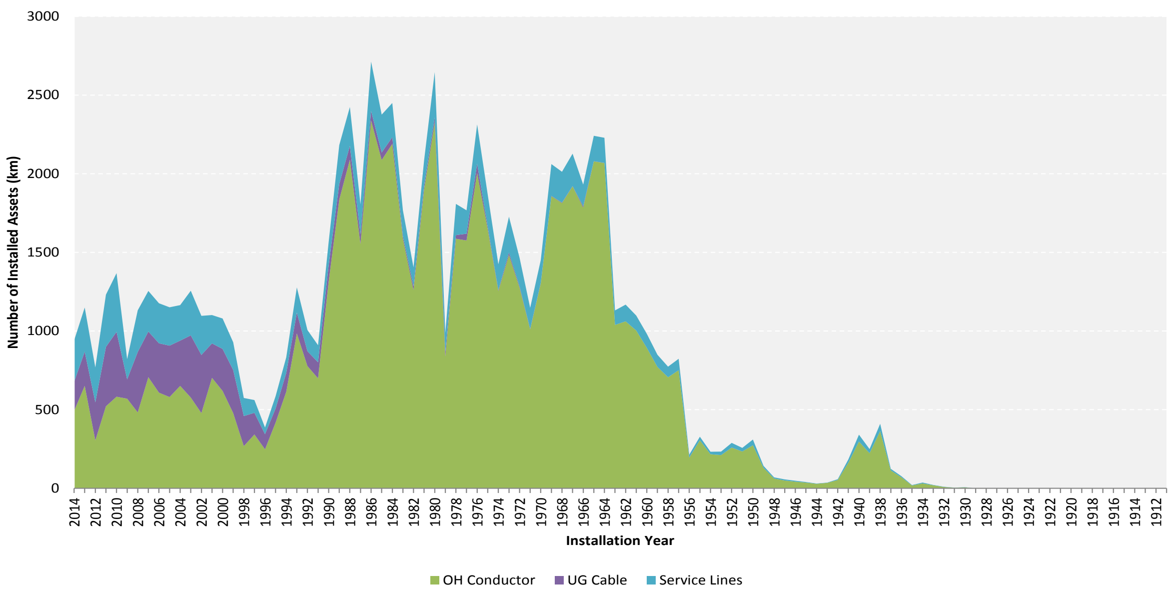
Further details of the replacement requirements for these assets are set out in the relevant asset management plans.

Costs for the replacement of these items of plant and equipment have been based on historical or current costs for similar projects, where materials, contract labour and services are sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects. Cost estimates have been obtained from a supplier for the material replacement programs.

3.2.2 Key drivers for expenditure

Powercor has an ageing network, with the majority of its current assets installed during the 1960s, 1970s and 1980s. This is shown in figure 3.11 containing the number of line assets installed (by kilometre) each year.

Figure 3.11 Powercor lines asset age profile



Source: Powercor

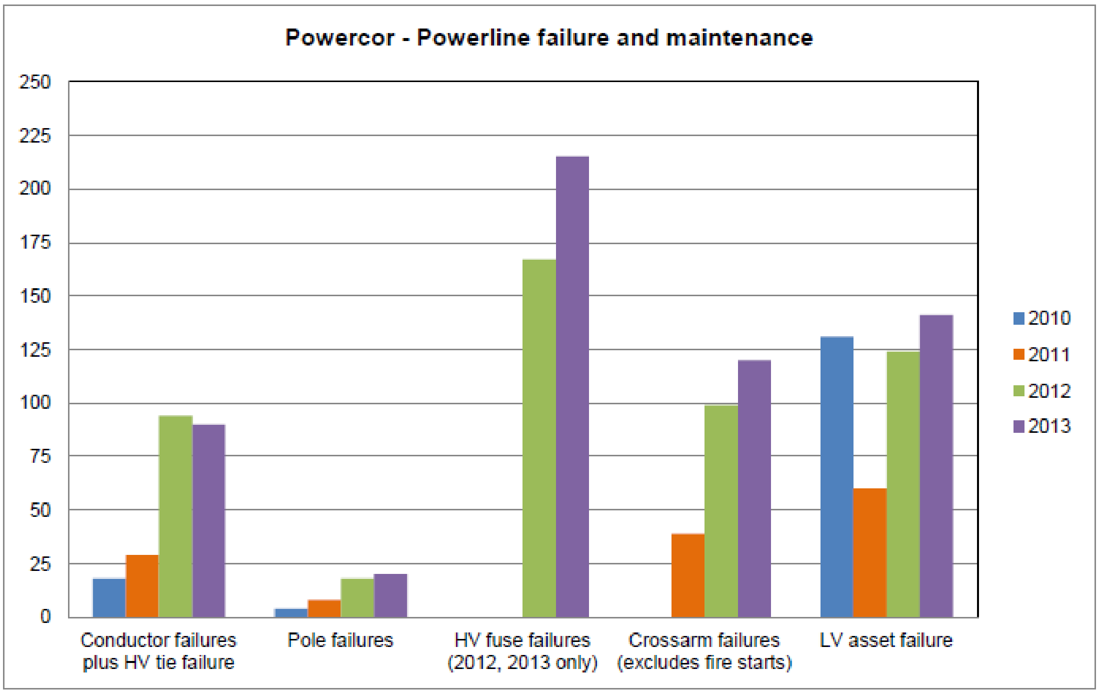
Ageing poles and wires

The asset profile above indicates that poles and overhead conductors are the largest categories of assets when weighted by replacement value. Energy Safe Victoria has recently commented on the increasing failure rate across Powercor's poles and wire assets, noting that:[16]

> *With all the capital expenditure (CAPEX) and operations (OPEX) expenditure of the network and the effort that has been put into condition assessment and asset replacement over the past few years, ESV would expect to see a reduction in the number of asset failures. Despite targeted programs, the number of asset failures has increased, especially power pole top, HV fuse, LV asset and bare conductor or HV ties. The failure rate remains high and a major cause of asset and vegetation fires. To reduce the failure rate of these assets, and the continuing risk to the community and its employees, the industry may need to review its risk-based and condition-based assessment techniques for the replacement of assets that are approaching the end of their useful life.*

Energy Safe Victoria's (**ESV's**) view of Powercor's increasing failure rate for poles and wires is shown in figure 3.12.

Figure 3.12 Powercor powerline failure and maintenance

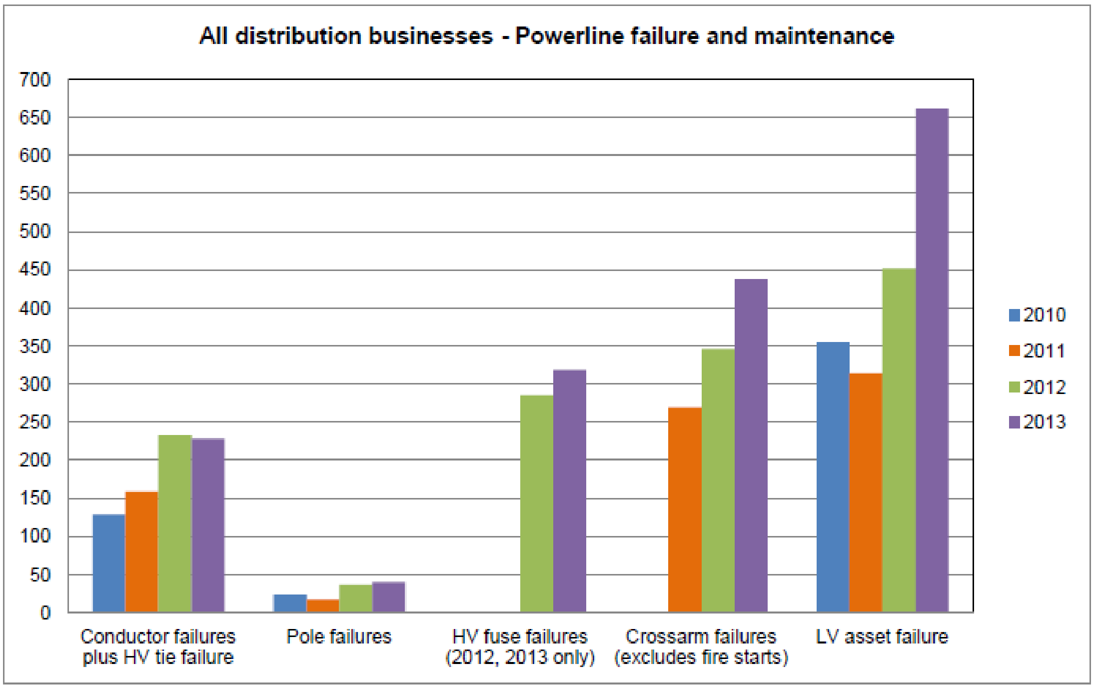


Source: ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, p. 64

Powercor's increasing failure rate is not inconsistent with the failure rates being observed by ESV across all of the Victorian distributors. The graph in figure 3.13 shows the increasing failure rate across all Victorian distributors.

16 ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, p. 61.

Figure 3.13 Powerline failure and maintenance across all Victorian distributors



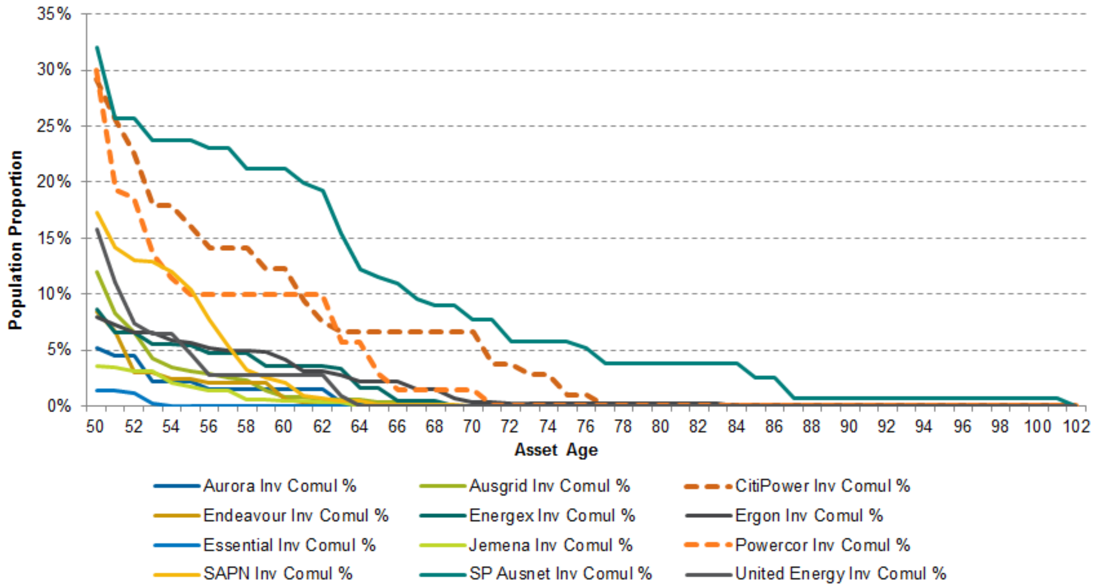
Source: ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, p. 62.

As the network ages, the failure rate on Powercor's poles and wires will continue to increase. Therefore, additional replacement expenditure will be required to ensure that Powercor is able to continue to maintain the quality, reliability and security of supply of its network in the provision of standard control services.

Ageing plant and equipment

Powercor also has old large plant and equipment. Figure 3.14 shows that over 30 per cent of Powercor's zone substation transformers are over 50 years old, and 10 per cent are over 60 years old. Powercor's transformers are amongst the oldest across all distributors.

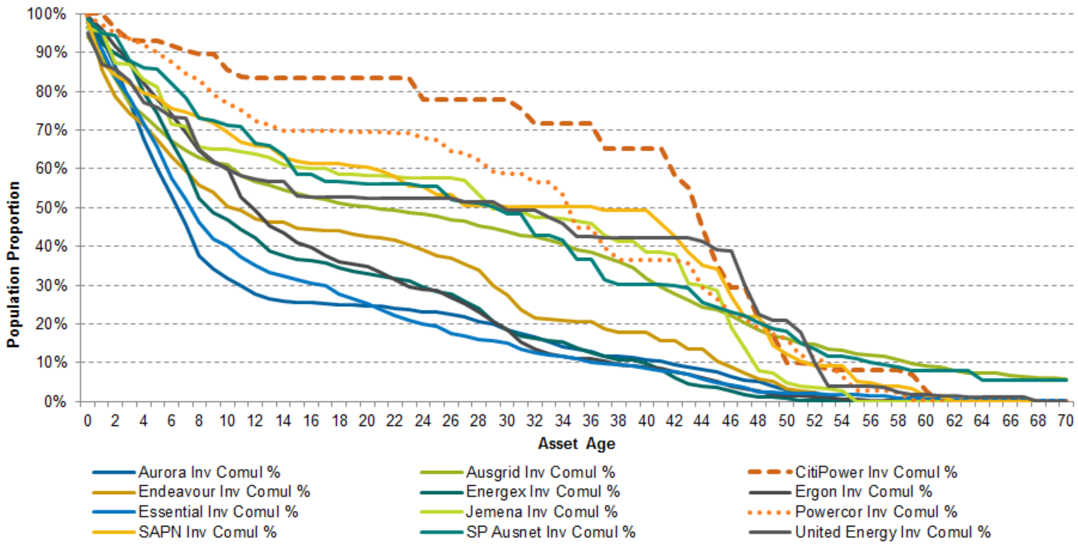
Figure 3.14 Zone substation transformers



Source: Powercor analysis using Category Analysis RIN

The average asset life of a circuit breaker is around 40 years. Figure 3.15 shows that for the majority of distributors, around 50 per cent of the circuit breakers are less than 20 years old. However, over 70 per cent of the circuit breakers in Powercor's zone substations are more than 24 years old, and 30 per cent are older than 50 years.

Figure 3.15 Zone substation circuit breakers



Source: Powercor analysis using Category Analysis RIN

The condition of Powercor's major plant and equipment will continue to deteriorate with age. Therefore, the forecast HI of these assets will need to be reviewed, which also takes into consideration factors such as environment and operational performance, to continue to maintain the quality, reliability and security of supply of the network in the provision of standard control services.

3.2.3 Comparison of unit rates

As discussed in the regulatory proposal, benchmarking of costs across distributors can only be appropriate when the following conditions hold:

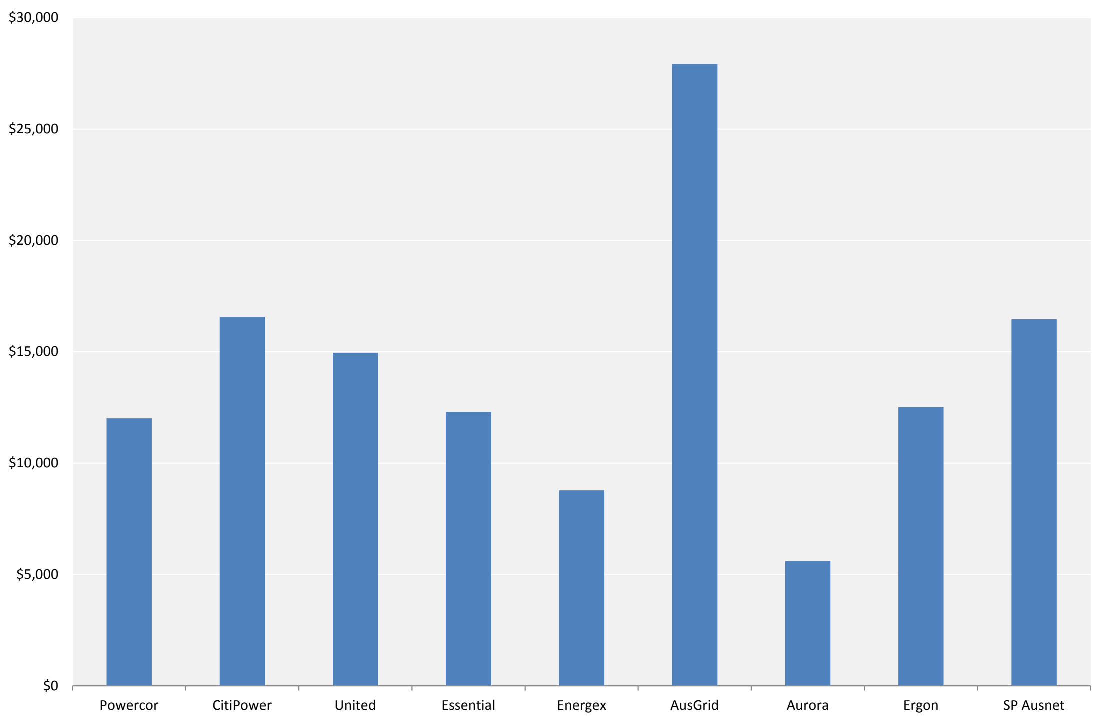
- consistent reporting and interpretations of costs;
- exogenous differences in operating environment are normalised; and
- costs reflect a representative and appropriate sample.

These conditions do not hold for the data for replacements contained in the 2013 Category Analysis RIN, and therefore the AER should be cautious in using the data to inform any of its decisions for the Regulatory Proposal.

Example 1 – replacement of 66kV wooden poles

Take for example the replacement of 22kV to 66kV wooden poles. The unit rate data shown in figure 3.16 represents the average cost over the period from 2009 to 2013, calculated by dividing the total expenditure by the total volumes over the period. Powercor's unit rate appears to be slightly below the average unit cost across all distributors, whereas CitiPower has one of the highest average unit rates.

Figure 3.16 Replacement of 22kV to 66kV wood pole ($/pole)



Source: Category Analysis RIN, Powercor analysis
Note: distributors with no data have been excluded from the graph

There is a significant difference in the number of wooden poles that the distributors have replaced over the reporting period. The Queensland distributors reported replacing over 1,000 poles each, Powercor replaced 220 poles, whereas CitiPower replaced 26 poles. The low volumes for CitiPower raises concerns that the sample size is not sufficient to be statistically significant.

Further, the operating conditions vary between distributors, as there are exogenous cost differences between undertaking works in an urban environment compared to a rural one. In regional and rural environments where Powercor operates, the following factors are relevant:

- longer distances-travel time to get to jobs may take longer than in urban environments;
- living away from home allowances-where a complex job in a remote location may take several days, accommodation and allowances may need to be paid to the personnel involved in the works;
- weather impacts-access to assets in regional and rural locations may be more difficult following weather events such as heavy rain, where the vehicles and elevated work platforms may become bogged, resulting in longer timeframes to undertake the works; and
- seasonal impacts-unplanned works undertaken on farms at certain times of the year may impact on crops, and compensation to the farmer may be required.

The methodology by which costs have been captured is likely to differ between distributors. As noted above, Powercor is unlikely to undertake a single job to replace a pole, rather it undertakes a package of work which may also involve replacement of the cross-arm, transformer, and other assets. As it is more efficient to undertake a package of works, most distributors would also be required to undertake an allocation of costs to the AER reporting categories. The allocation methods are likely to vary between distributors.

Given the uncertainty of the cost allocation methods between distributors, the different operating conditions, and in some cases the sample sizes are not large enough to determine unit costs, it is clear that the data should not be relied upon for benchmarking purposes.

Example 2 – replacement of 66kV circuit breakers and transformers

Comparison of unit rates from the Category Analysis RIN data relating to plant and stations is significantly impeded by difficulties and inconsistencies between distributors. This is apparent from the widespread variability between the unit rates.

For Powercor, there was a high degree of imprecision in mapping data from its internal reporting systems to the AER's Category Analysis RIN categories. This is because its internal asset management systems were established to capture data relating to the physical assets, but not the associated financial data. Powercor has separate systems that report financial data.

To populate the Category Analysis RIN, Powercor has obtained data from its asset register relating to the volume of assets. However, the asset register does not make a direct link between the asset created and the driver for the asset, i.e. whether the asset was a replacement asset or a new asset. Also, the internal asset reporting systems do not have a direct link to the cost of the creating the asset.

Costs are also not recorded at the asset level, but rather allocated to the internal reporting categories, i.e. function codes. But these codes are not at the level of granularity sought by the AER in the Category Analysis RIN.

Overall, population of the RIN has required shoehorning of the information from Powercor's IT systems into the AER's categories, which has involved considerable estimation, and despite best efforts, may be subject to error in terms of allocation of costs and volumes to asset groups and sub-categories. Powercor was not able to map all data from its systems to the AER categories.

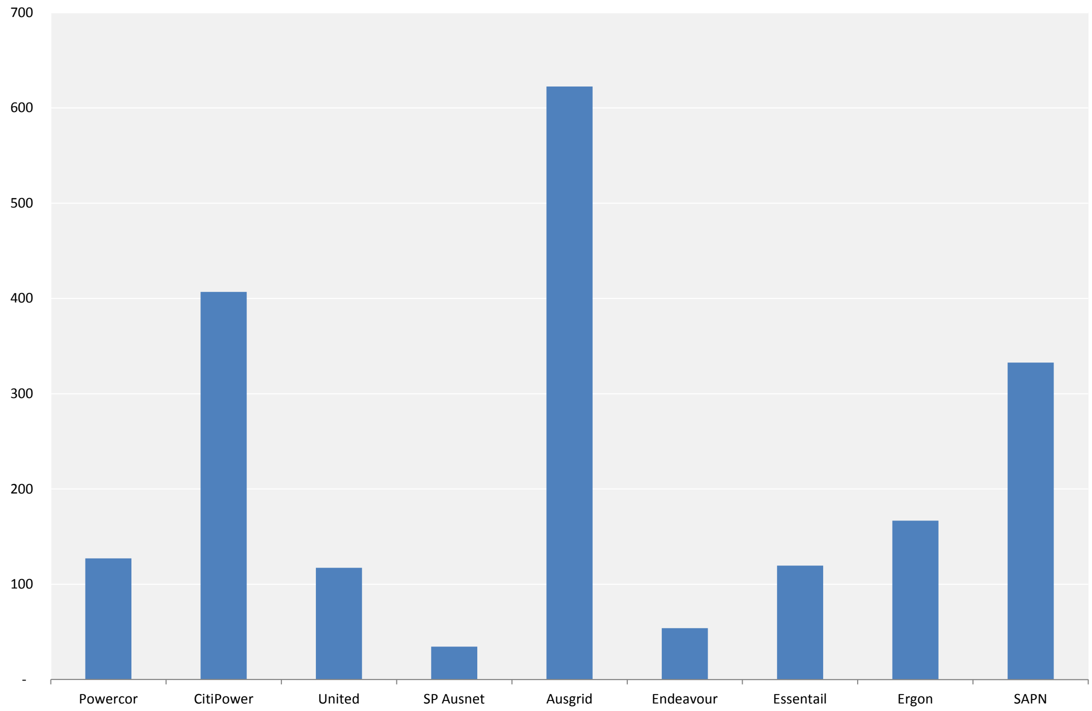
Powercor considers that its difficulties in providing accurately mapped information were widely shared with other distributors on the basis of:

- its industry knowledge of typical industry practice;
- the basis of preparation documents indicating that various estimation processes were undertaken; and
- several unit rates of other distributors are below realistic material-only costs.

The variability of unit rates for 66kV circuit breakers and 66kV transformers is shown below. It is clear from Powercor's comments below that the unit rate information from the Category Analysis RIN cannot be relied upon by the AER for benchmarking purposes.

The average unit rate for circuit breakers that operate above 33kV but less than or equal to 66kV is calculated by dividing the total expenditure by the total volumes over the period. The average is shown in figure 3.17.

Figure 3.17 Replacement of 66kV circuit breakers ($000/unit)



Source: Category Analysis RIN, Powercor analysis

There is a wide variance in the unit rates reported with averages as low as $34,000 per circuit breaker to $622,000 per unit. There is no apparent trend between similar distributors.

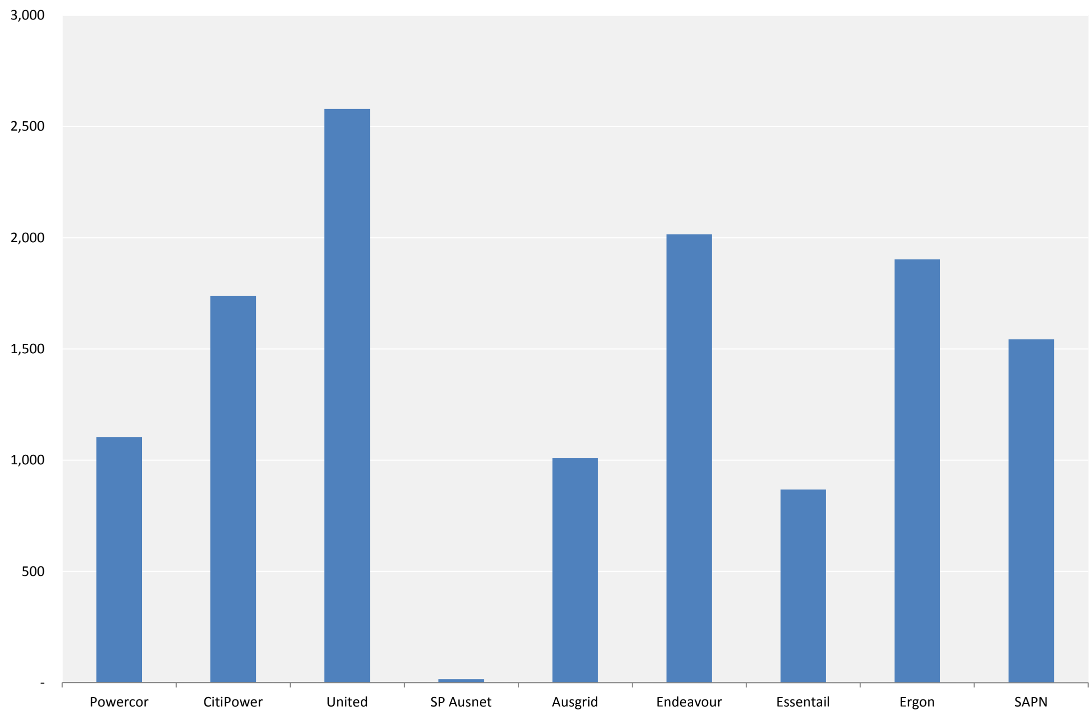
Some variance may be explained by the different types of circuit breakers, which differ by make and model. Currently, Powercor uses oil breakers, sulphur hexafluoride (SF6) and vacuum breakers in the network. For oil breakers, the oil needs to be filtered every five years, but the life can be extended if spare parts are available. An SF6 circuit breaker has a longer inspection cycle to check the gas levels, however is more costly to replace. Vacuum circuit breakers are relatively new, with lower maintenance costs to check the seal and the pressure and where necessary to replace the vacuum bottle, but are only used for voltages up to 22kV.

The type of circuit breaker installed in the network depends on the operating conditions. Powercor mostly has outdoor circuit breakers, whereas CitiPower has more indoor circuit breakers which use oil. For CitiPower, it is not always possible to individually replace a circuit breaker as it is part of the switchboard, and to replace would generally involve transfer of the entire load away from the zone substation or installation of a temporary switchboard.

Some variance in the unit rates may also be partly explained by the small reported volumes, where there is not a sufficient sample size to provide a robust average cost. It is noted that during the reporting period, CitiPower replaced 11 66kV circuit breakers and Powercor eight 66kV circuit breakers.

A second example is 66kV transformers. The average unit rate for ground outdoor/indoor chamber mounted transformers that operate above 33kV but less than or equal to 66kV, at rating of greater than 15 Megavolt Ampere (**MVA**) but less than or equal to 40 MVA, is calculated by dividing the total expenditure by the total volumes over the period, and is shown in figure 3.18.

Figure 3.18 Replacement of 66kV transformers (000s/unit)



Source: Category Analysis RIN, Powercor analysis
Note: distributors with no data have been excluded from the graph

Again, there is a wide variance in the unit rates reported, with rates from as low as $16,000 per transformer to $2.5 million.

Variance in the unit rates may partly be explained by the low volumes in the reporting period, such that the data is not statistically significant to draw any conclusions. CitiPower replaced one transformer that fitted the criteria. Powercor installed five replacement transformers.

Some variance in the unit rates may also be explained by the fact that the replacement of a transformer at a zone substation can involve the replacement of many other assets, such as fans, heat exchanges or water cooling systems, relays for controllers. The Category Analysis RIN data indicates that some, but not all, distributors included the additional costs associated with replacing a transformer. Others have included physical volumes that may relate to other assets. It is unclear what costs have been included by SP AusNet, given that the costs appear to be lower than the material cost of a transformer before labour and other costs are taken into account.

It appears, however, that for circuit breakers and transformers, the large variance in unit rates is primarily driven by difficulties and inconsistencies between distributors in completing the Category Analysis RIN. This is driven by the fact that the IT systems were not established to capture information in the manner sought by the AER, as the distributors have not required the information in that format to operate their businesses.

3.3 Historic spend

Powercor has continued to deliver a safe and reliable electricity supply during the 2011–2015 regulatory control period.

As a result of the asset inspection regime where the condition of each asset is reviewed, in the period from 2011 to 2013 Powercor:

- replaced over 4,000 poles;
- replaced over 40km of underground cables and 136km of overhead cables;
- replaced seven transformers in zone substations— the three transformers in the Castlemaine zone substation that had all been installed prior to 1950 were replaced with a single larger standard unit;
- replaced ten 66kV circuit breakers and 17 HV circuit breakers; and
- replaced control and protection equipment at 19 zone substations.

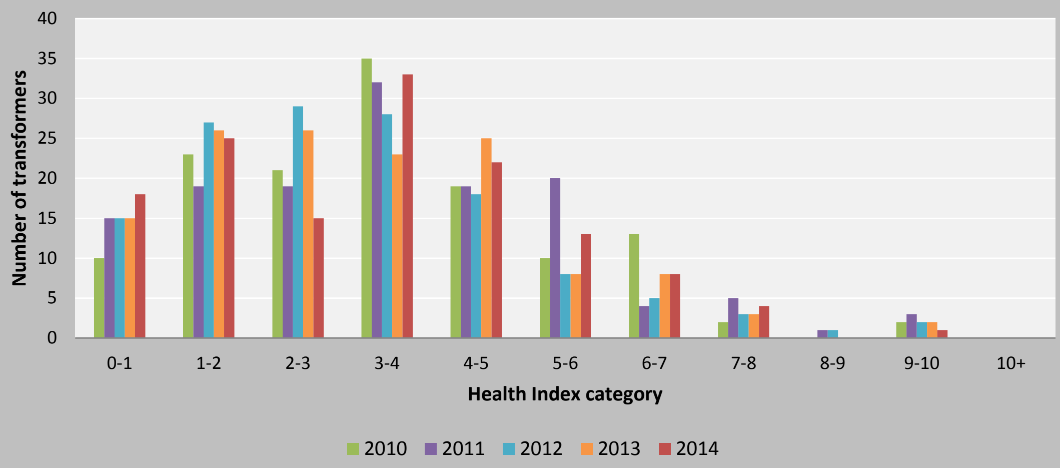
The above statistics do not include those assets that Powercor has refurbished or undertaken remedial action to correct defects to maintain and/or prolong the asset life.

In addition, Powercor received a direction in 2012 from ESV to install new generation Automatic Circuit Reclosers (**ACRs**) on SWER lines in specific high risk areas in the High Bushfire Risk Areas (**HBRA**). Prior to the summer of 2012/13, 179 new electronic SWER ACRS in the highest risk bushfire areas were installed.

Maintaining the health index

Powercor has maintained the HI profile of its transformers in zone substations over the current regulatory period, as shown in the figure below.

Figure 3.19 Maintaining the Health Index over the current regulatory control period



Source: Powercor

This demonstrates that Powercor's expenditure during the 2011–2015 regulatory control period was appropriate, with neither overinvestment nor underinvestment.

Overall, Powercor is forecast to overspend its regulatory allowance for replacement in the 2011–2015 regulatory control period by 1 per cent. Powercor's 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.

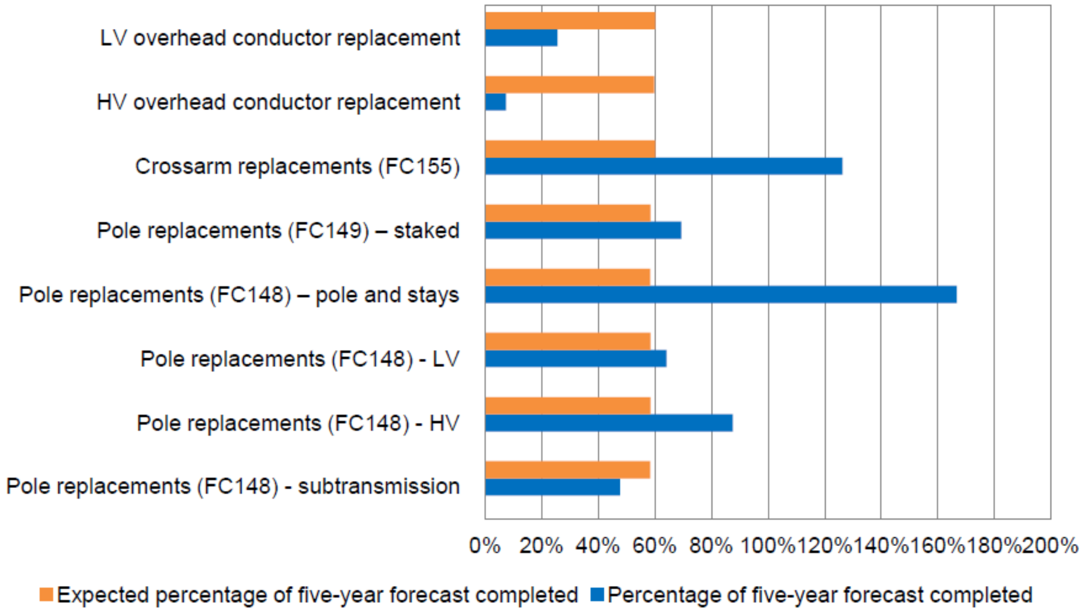
These matters are discussed in more detail below.

Higher expenditure for pole and cross-arm replacement

The increasing defect rate on poles and cross-arms was shown in Table 3.1 and Table 3.2 above. The increasing number of defects on these assets resulted in a higher volume of replacement for poles and cross-arms during the 2011–2015 regulatory control period.

The higher volume of replacements for poles and cross arms was also observed by ESV. Figure 3.20 shows the forecast replacements supplied by Powercor to the AER for the 2010-2015 revenue determination and annualised by the ESV to monitor progress.[17]

Figure 3.20 ESV view of Powercor five-year forecast – percentage completed



Source: ESV, *Safety Performance Report on Victorian Electricity Networks 2013,* June 2014, p. 37.

The higher volume of pole and cross arms replacements resulted in a higher expenditure than anticipated for this replacement category.

Lower expenditure for conductor replacement

Powercor intended to undertake an enhanced program of works to replace overhead conductors during the 2011–2015 regulatory control period. The enhanced approach was designed to ensure the reliability of the conductors was maintained in light of continued ageing and deterioration of the overhead conductor population, especially in the rural areas of the network not experiencing overhead line augmentations from demand increases.[18]

However, in response to the VBRC recommendation 27 to progressively replace all SWER line and 22kV feeders in Victoria,[19] the PBST was established to recommend to the Victorian Government how to maximise the value to Victorians from two of the VBRC's recommendations, including recommendation 27. The PBST's final report in September 2011 recommended the targeted replacement of powerlines with underground or insulated cable in the highest fire loss consequence areas.[20]

Powercor considered that it was not prudent to replace overhead conductors on a 'like for like' basis in HBRA given the anticipated requirement to replace those very same lines with insulated overhead

[17] ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, pp. 35-37.

[18] Powercor, *Regulatory Proposal: 2011 to 2015*, 30 November 2009, p.110.

[19] 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010.

[20] PBST, *Final Report*, 30 September 2011, p. 6.

powerlines, underground powerlines or new conductor technologies. As a consequence, Powercor paused the replacement program for overhead conductor in HBRA areas in 2011.

Discussions between Powercor, the PBST through the now Department of Economic Development, Jobs, Transport and Resources (**DEDJTR**), and ESV to identify the areas where lines should be replaced occurred over the 2011-2014 period.

On 11 July 2014, Powercor received a Direction from ESV to replace bare overhead powerlines in 2014 and 2015 in the South Western District of Victoria.[21] The replacement of the lines will be funded by the Powerline Replacement Fund (**PRF**), but not in its entirety. Rather, the PRF funds the costs of the project less an amount being the 'avoided cost' calculated in accordance with *Electricity Industry Guideline No. 14* (**Guideline 14**). Pursuant to Guideline 14, where a distributor makes an offer to underground distribution assets, the distributor is to contribute towards the costs of the undergrounding an amount equal to the distributor's 'avoided costs'.[22] The AER approved the application by Powercor to pass through the total project costs less the capital contribution by the PRF and the associated tax liability.[23]

Powercor recommenced the program to replace overhead conductors in 2014.

Replacement of SWER ACRs

While Powercor paused the program to replace overhead conductor in high risk bushfire areas, it received a Direction from ESV to install new generation ACR to SWER lines.[24]

The Direction issued on 5 April 2012 required Powercor to ensure that its Bushfire Mitigation Plan (**BMP**) provides:

- that sufficient ACRs are installed by 30 November 2012 to eliminate the need to attend and manually suppress the automatic reclose function on any SWER lines in the areas of highest 80 per cent fire loss consequence on total fire ban and code red days;
- the development of a program by 31 August 2012 to ensure that the protection settings and reclose functions can be remotely controlled by Powercor's SCADA system for
  a) all SWER ACRs that cannot be remotely controlled by Powercor's SCADA system; and
  b) SWER fuses downstream from the SWER isolating transformer (excluding distribution substation fuses).

Powercor submitted its revised BMP to ESV in June 2012. As a consequence, Powercor replaced 179 SWER ACRs and 37 ACRs on fuse protected SWER systems located in the highest 80 per cent consequence areas.

This program of work was not anticipated at the time of the 2011-2015 AER determination, nor was it covered in Powercor's cost pass through application for costs arising from the VBRC.[25]

21 ESV, *Direction under section 141(2)(E) of the Electricity Safety Act 1998 — Powerline Replacement Projects quoted for by Powercor and funded by the Victorian Government's Powerline Replacement Fund*, 11 July 2014.

22 Guideline 14, clause 2.2.

23 AER, *2011-15 Powerline Replacement Program cost pass through for Powercor*, Determination, September 2014.

24 ESV, *Direction under section 141(2)(D) of the Electricity Safety Act 1998 — Installation of new generation electronic Automatic Circuit Reclosers (ACRs) to Single Wire Earth Return (SWER) lines,* 5 April 2012.

25 AER, *Powercor cost pass through application of 13 December 2011 for Costs arising from the Victorian Bushfire Royal Commission*, Final Decision, 7 March 2012.

Network expenditure replacement requirements have changed between the previous, current and forthcoming regulatory control periods as a result of changes to inspection cycles. Distribution businesses were required to change their asset inspection standards and procedures in areas of high bushfire risk areas following the VBRC recommendations.

3.4 Forecast spend

Powercor requires a 58 per cent increase in replacement expenditure compared to its actual spend during the 2011-2015 regulatory control period. The expenditure forecast is driven by:

- the increasing failure rate on poles and cross-arms;
- continuation and increase of the replacement of high-voltage overhead conductor program; and
- additional replacement of transformers and switchgear in the network given the Health Indices are forecasting increased network risk which needs to be managed to maintain acceptable risk levels.

Each of these factors is described in turn below.

Increased number of deteriorated poles and cross-arms

In the 2011–2015 regulatory control period, Powercor has replaced significantly more than forecast volumes of poles and crossarms, as noted by ESV and discussed above. However, Powercor still experienced an increase in the failure rates on poles and cross-arms during that time, indicating that the increasing replacement rates are necessary to maintain the performance of the assets.

As the ESV noted:[26]

> *Over time, the network operating environment, duty cycle and network events contribute to the ageing of assets. These require maintenance or replacement to reduce the probability and rate of asset failure. The rapid rate of electrification of Victoria during the middle of last century means that* many assets are nearing the end of their initial design life….
>
> *Despite a targeted condition assessment and asset replacement program to reduce breakdowns, the number of asset failures has not reduced for all asset classes, especially crossarms and HV fuses. To reduce the asset failure rate, the industry may need to review its condition assessment techniques and reliability approach to asset replacement…*

Poles and cross-arms are maintained using the reliability and safety regime process that has been discussed above. The process involved using the historical defect rate for these assets, combined with the forecast number of poles to be inspected, to estimate the forecast number of defects over the 2016-2020 regulatory control period. A higher number of defects is estimated for the forecast period compared with the 2011-2015 period. This is a key driver of the step up in replacement capital expenditure required for the 2016–2020 regulatory control period compared to the current period.

Recommencement of the proactive conductor replacement program

In the 2011-2015 regulatory control period, Powercor planned to undertake an enhanced program of works to replace overhead conductors given their expected deterioration rate. However, as discussed above, this proactive program was placed on hold following the PBST's recommendation to underground or install insulated cable in the highest fire loss consequence areas. Powercor

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[26] ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, p. 31.

considered that it was not prudent to replace overhead conductors when those same lines may be required to be placed underground.

Powercor recommenced the proactive conductor replacement program in 2014. This entire program of work is expected to continue over the 2016-2020 regulatory control period and beyond, especially in the rural areas of the network.

The program is necessary given the increasing risk associated with the ageing profile of overhead conductors and increasing trend of failures. A high proportion of Powercor's conductors were installed during the 1950s and 1960s. The conductors installed at this time were predominantly galvanised steel conductor and is now aged between 45 and 65 years.

Parsons Brinkerhoff found that it is prudent and efficient to increase the expenditure on replacing overhead cables to mitigate the risk of conductor failure over an extended planning horizon.[27] This was based on the projected escalation of failures as the age of conductors approached the end of life of 50 years in coastal environments through to a maximum of 80 years inland.

The conductor failure trend indicates emerging issues and an increasing risk to Powercor's network and the health and safety of communities due to the ageing conductor population. This is demonstrated by the increasing rate of conductor failures and defects. When failure rates are projected using conductor age as a primary proxy for conductor condition, failures rates are expected to increase sharply over a 20 year outlook supporting the need for a proactive conductor replacement strategy.

Additional replacement of transformers and switchgear

To maintain the HI profile of transformers at zone substations, Powercor needs to replace or refurbish the transformers at the following zone substations during the 2016–2020 regulatory control period: Charlton, Echuca, Robinvale, Sunshine, Terang, Warrnambool, and Winchelsea.

The high HI associated with circuit breakers in around eight zone substations also needs to be addressed. This includes 13 circuit breakers in the Ballarat North, Eaglehawk, Geelong City, Hamilton, Koroit, Portland, St Albans and Shepparton zone substations. Powercor's policy is to refurbish many of these circuit breakers, as it prolongs their operational life and is a much cheaper option than a full replacement.

Similarly, for 11kV and 22kV switchgear the intervention program includes both replacement and refurbishment strategies to address the advancing HI profile. Powercor intends to replace 27 circuit breakers in five zone substations and refurbish 50 circuit breakers in ten zone substations, as per table 3.5.

[27] Parsons Brinckerhoff, *Overhead conductor replacement investment strategy*, May 2010.

Table 3.5 Replacement and refurbishment of 11kV and 22kV switchgear

Replacement	Refurbishment
Cobram East	Ballarat North
Maryborough	Brooklyn Terminal Station (for Powercor assets)
Nhill	Corio
Ouyen	Geelong
Sunshine	Laverton
	Merbein
	Mooroopna
	St Albans
	Warrnambool
	Waurn Ponds

Source: Powercor

Powercor's plans for the refurbishment of circuit breakers clearly demonstrates the efficiency of its forecasts as the cheaper alternative has been selected to prolong the life of the asset, rather than the more costly option of asset replacement.

Checking the appropriateness of transformer and switchgear forecasts

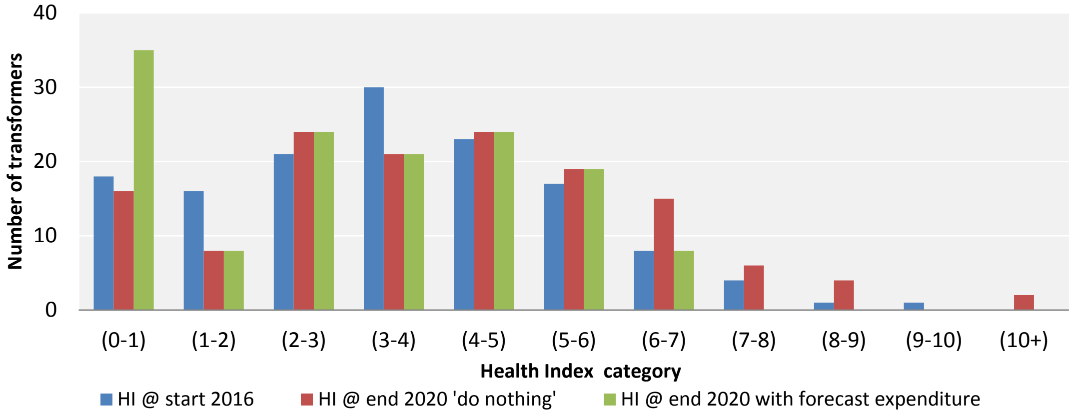
As noted above, Powercor is able to undertake a top-down check that its expenditure forecasts for transformers and switchgear are reasonable, sustainable and will enable the prudent and efficient management of its ageing and deteriorating large assets using current strategies, maintenance policies and operating practices by using the HI profile predictions for future years.

Powercor has created the HI profile at the start of the 2016–2020 regulatory control period and compared that to:

- the profile that would occur in the 'do nothing' scenario over the 2016–2020 regulatory control period; and
- the profile that would occur if it undertakes the investments set out in this regulatory proposal.

Using transformers in zone substations as an example, figure 3.21 shows that Powercor's forecast expenditure is reasonable as it is able to appropriately maintain the number of transformers with a HI of seven or above, as well as maintain the overall HI profile. If Powercor did not undertake any investment over the 2016–2020 regulatory control period, then the number of zone substations with transformers with a HI of seven or above would rise from six to 12.

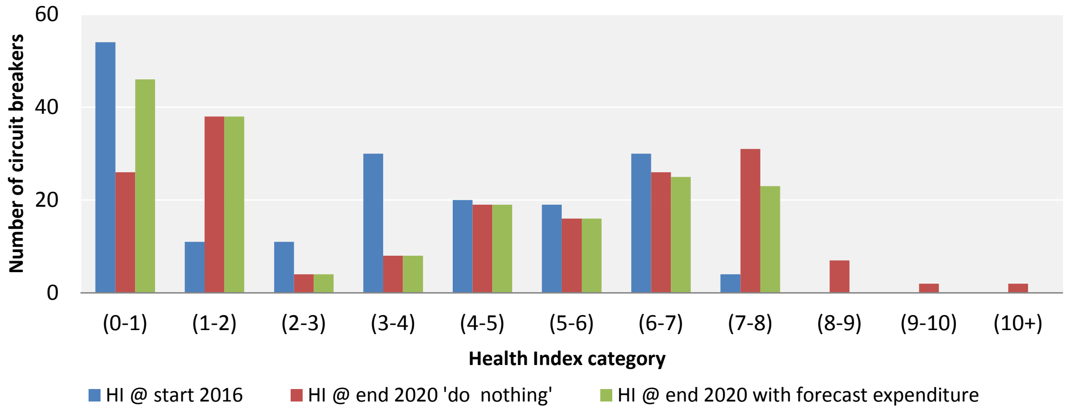
Figure 3.21 Transformers health index in 2020 with and without investment



Source: Powercor

Powercor has undertaken similar analysis for its 66kV circuit breakers, as show in figure 3.22. The figure clearly demonstrates that without remedial action, over 10 circuit breakers will have high values of the HI with an associated high probability of failure.

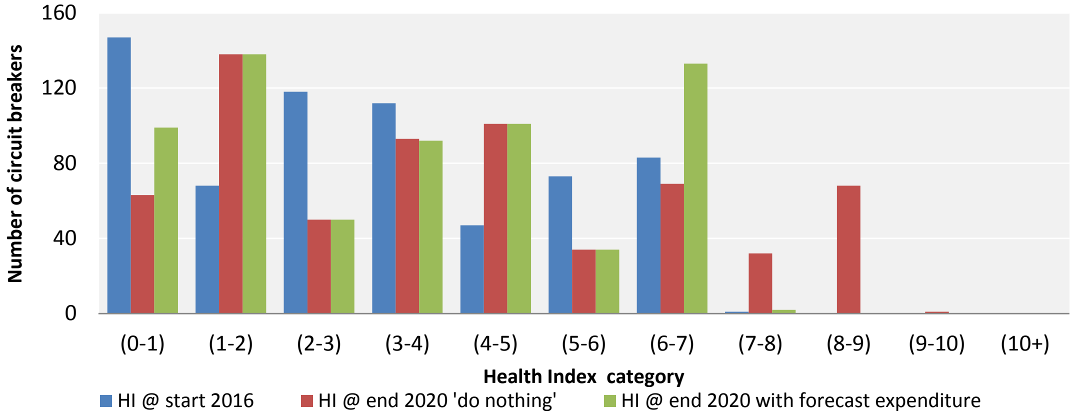
Figure 3.22 Health index of 66 kV circuit breakers



Source: Powercor

Finally, Powercor has undertaken analysis of the Health Indices of its switchgear, comprising 22kV and 11kV circuit breakers, per figure 3.23. It can be seen that a large number of circuit breakers will have a high value HI unless the investments outlined in this Regulatory Proposal are undertaken in the 2016-2020 regulatory control period.

Figure 3.23 Health index of switchgear (22kV and 11kV circuit breakers)



Source: Powercor

Powercor's expenditure forecast is targeted at replacing or refurbishing those assets with a HI of seven or greater over the 2016–2020 regulatory control period. The accelerating effort to maintain the HI profile reflects the large proportion of switchgear that is approaching end of life, given that the majority were installed in the 1960s and 1970s.

Innovative solutions used in maintenance of assets

Powercor will continue to consider the changing energy landscape and technological changes in its approach to maintaining and repairing assets.

In areas where energy and peak demand consumption is declining, Powercor may consider using treated pine for electricity poles rather than hardwood. Treated pine is a cheaper alternative to hardwood, however it does not have the longevity. This means that Powercor will have a smaller stranded asset base should its customers choose to solely rely on off-grid solutions for their energy in the future.

Inspection processes will also take into account technological advancements. Powercor is planning to consider the use of drones to capture and record information on the state of its assets, rather than onsite visits by asset inspectors.

3.4.1 Programs and projects

Table 3.6 provides an overview of the large programs of work over $5 million that Powercor intends to undertake during the 2016-2020 regulatory control period.

Table 3.6 Network service material projects

Project name	Driver	Direct cost ($2015, million)	Material project #
Proactive conductor replacement program	Condition and safety	73.8	REPL 20
Sunshine zone substation redevelopment	Condition	3.9	REPL 21
Bulk replacement of Capacitive Voltage Transformers (CVT's)	Safety	8.8	REPL 22
Robinvale transformer replacement	Condition	9.2	REPL 23
Air break switch program	Condition and safety	8.1	REPL 24
Environmental Bunding program	Safety	3.4	REPL 25

Source: Powercor
Note: direct costs excluding real escalation

The proactive conductor replacement program has been discussed above. The remaining programs are described in more detail below.

Sunshine zone substation refurbishment

Sunshine Zone Substation (**SU**) supplies electricity to over 25,000 customers including domestic, commercial and industrial in the Sunshine, Ardeer, Deer Park, Laverton North, St Albans, Caroline Springs and Derrimut areas.

In response to the existing SU transformers nearing end of life and additional load requirements brought on by new data centres in the area, Powercor commenced a program to refurbish and redevelop the zone substation over the 2012 to 2017 period.

The SU zone substation comprised four transformers and outdoor discrete HV switchgear. Two transformers are in service and a group of two smaller transformers are available for contingency operation. The transformers have no voltage regulation and are of limited use. All transformers at the station are aged and in poor condition.

The HV switchgear (outdoor circuit breakers) are aged and also in poor condition. The HV bus structure is currently supported as a long term temporary measure with scaffolding. Other station components including the capacitor banks, buildings and fences are in poor condition.

To finalise the redevelopment of the SU zone substation, Powercor needs to decommission and remove two of the old transformers and associated equipment. This is contingent upon the establishment of Deer Park Terminal Station (**DPTS**) to enable load transfers.

Bulk replacement of CVT's program

Powercor has a population of high voltage Plessy Ducon Capacitive Voltage Transformers (**CVTs**) that are ageing. They are generally more than 40 years old.

Following the catastrophic failure of one of the bushings on a CVT, resulting in broken porcelain scattered across the zone substation yard, Powercor considered methods to mitigate the health and safety risks posed by the equipment. The only effective solution to address the health and safety risk is to replace the ageing CVT's with modern Inductive Voltage Transformers (**IVT**s).

There are 27 three-phase sets and 18 single-phase installations of these CVTs in the Powercor network. Powercor has begun replacing these units and intends to progressively replace the remaining units over the period to 2020.

The porcelain bushing program is in line with Powercor's *Asset Management Framework 2015.*

Robinvale transformers project

The Robinvale (**RVL**) zone substation supplies the domestic and commercial area of Robinvale extending into surrounding rural areas, including large pumping loads for the irrigation of farmland and orchards. It comprises three 5/6.5MVA 66kV/22kV transformers in banked configuration.

All three transformers were manufactured in 1950 and are currently 65 years old. Their condition and age places them at or very near end of life, with health indices forecast to be around seven by the end of 2020.

Table 3.7 Health Indices of transformers at Robinvale zone substation

Transformer	Health Index (2014)	Health Index (end of 2020)	Calculated time from 2014 to end of life (Years)
RVL T1	6.06	7.27	3.68
RVL T2	6.06	7.27	3.70
RVL T3	5.80	6.93	4.92

Source: Powercor

Powercor has been monitoring these transformers closely and undertaking actions such as line drying to further extend their service life. Further life extension works are now not effective as the condition and age of these units approaches end of life.

Powercor intends to replace the three existing transformers with new standard 10/13MVA transformers in a staged manner over a four year period, commencing in 2017.

Air break switches program

Powercor installs air break switches (**ABS**) on the 22kV high voltage overhead network as a means of sectionalising the HV network. The switches are used to:

- isolate sections for planned and unplanned works;
- restore supply of electricity; or
- connect between different HV line sections as a part of switching activity to maintain supply to customers whilst other sections are de-energised for various purposes.

Following a coroner's inquest after the death of a lineworker from an ABS, Powercor is required to regularly maintain the switches. The switches are inspected and maintained in the field on a ten year cycle, in accordance with the Powercor switch inspection policy.

Many ABSs are maintained or replaced following the identification of defects through the routine inspection policy, or through *ad hoc* defects noted during unrelated maintenance activities. The replacement of ABS is prioritised based on its network location or operational needs.

The continuation of this program to replace air break switches is necessary to maintain flexibility in the Powercor network, and for health and safety reasons following the coroner's recommendations into the maintenance these assets.

The air break switches program is in line with the attached *Asset Management Framework 2015.*

Environmental bunding program

Electricity networks may potentially create soil contamination and groundwater pollution through the operation of network equipment containing significant volumes of oil. Such equipment is used for switching, transforming and delivering energy. One of the largest oil filled network elements that present a risk to the environment of oil leakage are power transformers in zone substations which may leak material volumes of oil as their condition deteriorates.

Victorian contamination and wastewater protection is regulated by the Environment Protection Authority under the State Environment Protection Policy (**SEPP**). The SEPP for contamination stipulates that the occupier of any site must ensure that the land is managed to prevent contamination and must apply best practice in this regard. The SEPP that governs groundwater contamination states that all practicable measures must be taken to prevent pollution of ground water and stormwater.

One of the recognised most effective treatments for transformer oil leak risk is the containment and treatment of leaks via bund walls. A bund wall is a complete enclosure built around the transformer that contains any oil spills within the wall boundary until such time that it can be treated or removed. Coupled to this is the treatment of water at the site to separate oil from water before it enters the storm water or ground water systems.

CitiPower and Powercor have an ongoing program to install bunding and drainage at zone substations, where insufficient bunding and drainage exists, so as to meet regulatory requirements and the Australia Standard 1940.

For the 2016 to 2020 period, Powercor has identified the Warrnambool (**WBL**), Geelong B (**GB**), Cohuna (**CHA**), Mildura (**MDA**) and Camperdown (**CDN**) zone substations as having the highest environmental risk where it will undertake bunding and drainage programs to ensure compliance with environmental regulations and standards.

The bunding program is in line with the attached *Asset Management Framework 2015.*

3.5 AER repex model

In the Forecast Assessment Expenditure Guidelines, the AER indicated that it will use the 'repex model' as part of its assessment of the proposed replacement capital expenditure. The repex model is a high-level probability based model that forecasts replacement for various asset categories based on their condition (using age as a proxy) and unit costs.[28] This model has previously been applied to Powercor by the AER in the 2011-2015 regulatory determination.

The AER recognises that there are a range of factors that can influence the replacement life for an asset, including the:

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28 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 185.

- operational history;
- environmental condition (e.g. damp or dry, or coastal or inland); and
- quality of its design and installation (including early-life failures of assets).[29]

The AER considers that the remaining life of an asset is a function of a number of factors, most notably its condition, and therefore a population of similar assets will have a range of lives.

Given the complexity of predicting the replacement of individual assets, the AER considers the purpose of the repex model is to simplify the analysis but still maintain some accuracy at the aggregate level.[30]

The repex model simplistically predicts the volume of replacement based on the age of system assets on a distributor's network. To do this, the model requires information for each asset category on the age profile, replacement lives including the mean replacement life and standard deviation, and unit costs. The 'base case' model is then calibrated to determine the asset lives and unit costs that represent the historical replacement level of the distributor over the preceding five year period. The calibrated model is considered the 'benchmark model' in circumstances where the AER is satisfied that the historical replacement levels reasonably reflect prudent and efficient expenditure.

As the repex model simplifies a complex range of factors to forecast the replacement of assets, it has inherent limitations including:

- the life of assets replaced in the past is assumed to be the same as for assets replacement in the future, such that the repex projections are backward looking and may differ significantly from a truly optimal forward looking replacement program;
- assumption that recent past replacement expenditure reflects implementation of an optimal replacement strategy;
- the number of units replaced in the past is directly proportional to historical expenditure;
- use of asset age as a proxy for the many factors that drive individual asset replacement, where other drivers such as safety or environmental standards may be the primary driver for particular asset categories;
- assumption of a normal distribution profile around the mean for the replacement life of each asset category, where there is likely to be a high degree of variability around the 'mean' age that limits the accuracy of its use in predicting volumes for replacement; and
- sample sizes may be too small for some asset sub-categories to be statistically significant, and thus may lead to inaccurate results.

In light of the limitations of the model, the AER suggests that it will only use the repex model to cross-check the forecasts of a distributor where those forecasts appear to be deficient. The AER notes:[31]

> *It should be recognised that the mangers of capital assets will frequently rely on alternative techniques to determine their asset replacement strategies. A particular approach may include critical impact, condition based or risk based techniques or a mix of these or other techniques.*

[29] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 9.

[30] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 9.

[31] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 10.

> *The repex model approach does not replace those techniques. They are all valid approaches and may give superior estimates of replacement need in particular circumstances. However, if the explanations of proposed replacement volume or cost are found on closer examination to be deficient, then the repex model will provide an alternative point of reference for consideration.*

Powercor has therefore provided below a cross-check of its own forecasts with the repex model to demonstrate that its replacement expenditure forecasts are robust.

3.5.1 Output of the repex model

As noted above, the AER's repex model simplistically predicts the volume of replacement based on the age of system assets on a distributor's network.

The AER's model indicates that the largest category of replacement costs will be for poles, which is consistent with Powercor's own forecasts based on the defect rates of the assets. The repex model also forecasts a large amount of expenditure for switchgear and transformer replacement.

However, the repex model uses history to 'calibrate' the average replacement lives of assets across the business. This leads to results that are outside the normal industry expectations.

For example, in reviewing the model in 2010, Parsons Brinckerhoff found that the asset lives determined by the repex model were not reasonable. PB found that:[32]

> *PAL's Secondary Systems activity code which was subject to an average life extension of 16 years over the PAL proposed life of 41 years. In PB's opinion this ignores the fact that equipment in this category is typically replaced due to obsolescence, withdrawal of vendor support, or the unavailability of spares. In practice, the likelihood of achieving an average service life extension of this magnitude is extremely low without accepting the considerable amount of additional risk, or incurring mitigating expenditure associated with operating obsolete equipment.*
>
> *In our opinion, a difference of this magnitude between the calibrated life and practical considerations reinforces our view that the model is not robustly calibrated to time based failure modes. Noting the significant adjustment applied by Nuttall's for this activity code, PB considers that the use of a calibrated life that is well beyond normal industry expectations, may significantly understate the reasonable level of total replacement capex required over the next regulatory control period.*

As a result, the repex model may understate the level of capital expenditure that Powercor will require to replace some categories of assets.

A detailed description on the data and methodology that Powercor has used in populating the repex model is provided in the attached report by Jacobs, *Powercor repex modelling review*.[33] This report includes an independent review and validation of the population and running of the model, which was compared against the AER's *Replacement expenditure model handbook*.

3.5.2 Reconciliation

The repex model forecasts a lower level of overall expenditure for replacement related works compared to Powercor's forecasts.

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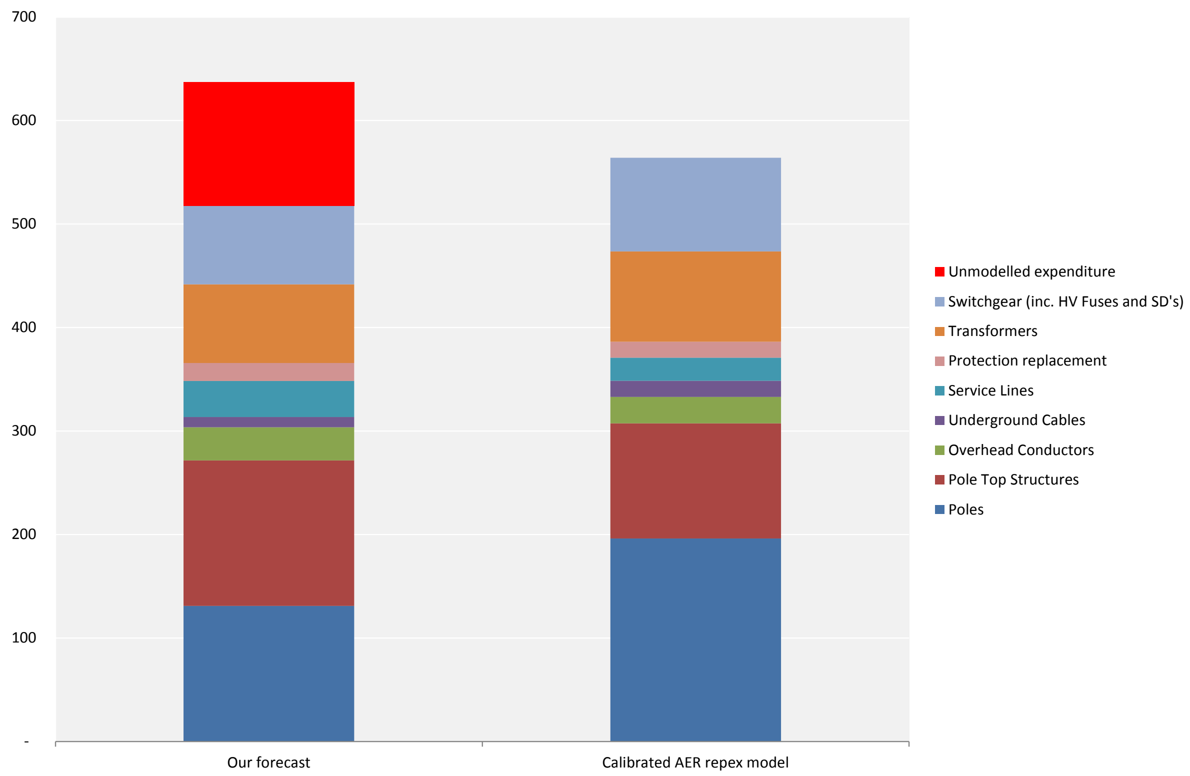
32 Parsons Brinckerhoff, *Repex model review CitiPower – Powercor*, July 2010, p. vi.

33 Jacobs, *Powercor repex modelling review*, 17 April 2015.

For the elements of replacement expenditure where the cost drivers are covered by the repex model for standard control services, the forecasts are 8 per cent lower than the forecasts from the repex model. This is shown in figure 3.24.

Figure 3.24 Comparison of Powercor's forecast to repex model forecast output ($million, 2015)



Source: Powercor
Note: direct costs excluding real escalation

Categories where the forecast is higher than the repex

Powercor's expenditure forecasts propose more capital expenditure than the AER' repex model in the categories of pole top structures, overhead conductors, service lines and protection.

Powercor notes that:

- for pole top structures, overhead conductors and service lines-the historical defect rate is used in preparing the forecasts, rather than focusing solely on the age of the asset population; and
- protection relays-Powercor's relay replacement program will be focussing on prioritising replacement of voltage regulating relays, whereas the current program has prioritised protection relay replacements. The risk profile of voltage regulating relays is forecast to significantly increase, as the technology is approaching end of life. The unit costs of voltage regulating relay schemes is higher than those of protection relay schemes.

Unmodelled replacement expenditure

The repex model is not expected to reflect all of the replacement costs for assets incurred by a distributor. The AER 'expects that the chosen sub-categories should represent between 70 to 80 per cent by value of replacement expenditure'.[34] Powercor estimates that 81 per cent of its proposed replacement expenditure is captured by the drivers in the repex model.

The repex model does not cover those assets that are either not replaced by age, or are not defined by a detailed asset age profile required by the repex model, including:

- proactive replacement programs;
- property, buildings and associated facilities;
- asset refurbishments and component replacements; and
- environmental expenditure.

A proactive replacement program is underway to replace overhead conductors given the expected deterioration rate, however this is not taken into account in the AER's repex model.

AER's repex model does not include costs such as property refurbishments, such as replacing a roof on a zone substation, replacement of fences, and general maintenance activities. These costs are essential to maintaining the distribution network, but are not associated with an age profile and thus are excluded from the repex model. For example, it does not include building civil replacement costs associated with the Sunshine zone substation.

The repex model also does not capture expenditure associated with management of environmental matters, for example, the reduction of noise pollution in excess of Environmental Protection Authority standards, or the replacement of line coverings preventing bird interference.

[34] AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013, p. 13.

4 Augmentation

> To ensure that Powercor continues to support the growth and development of its communities, investment in high growth areas needs to be targeted to meet expected demand. That is, the capacity of the network needs to be increased where it is forecast that customers will demand more electricity than the network capacity in that location, particularly on extremely hot days when air-conditioners drive up demand.
>
> Powercor's proposed capital expenditure will also allow it to undertake augmentation to maintain the security, reliability and quality of supply of the network.

This section discusses Powercor's historical and forecast augmentation expenditure as well as its approach to calculating the expenditure.

4.1 Overview

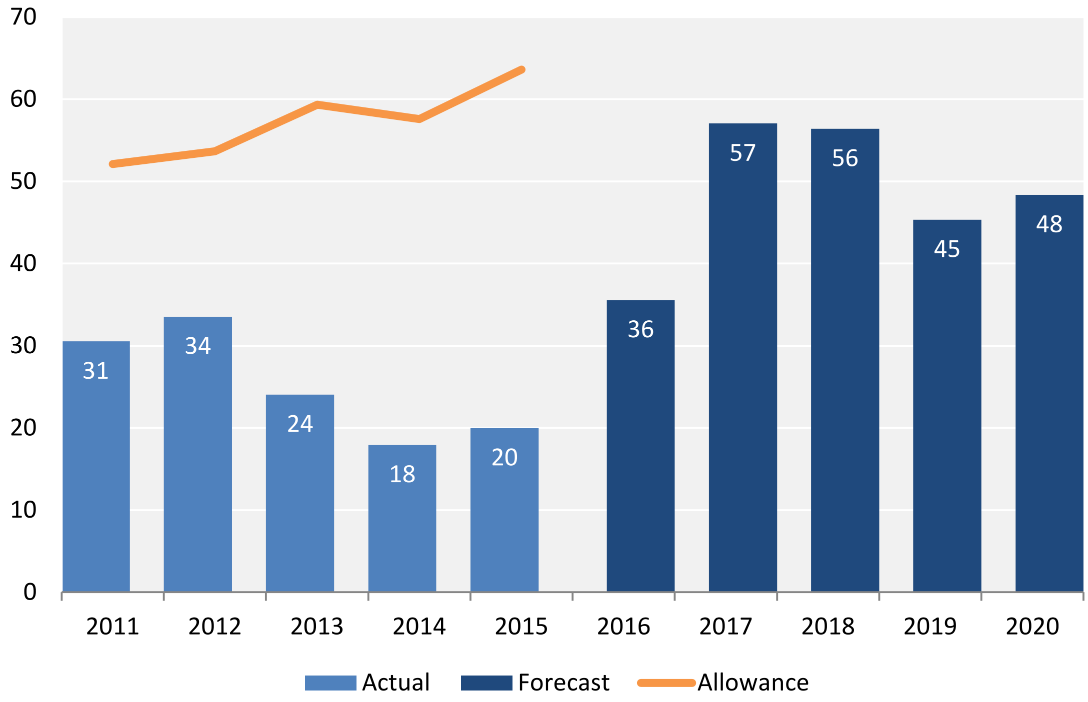
Augmentation capital expenditure is required to achieve the capital expenditure objective to meet or manage the expected demand for standard control services over the 2016-2020 regulatory control period.

Augmentation capital expenditure comprises:

- demand driven expenditure to upgrade the capacity of the existing distribution network, in response to spatial demand growth;
- non-demand expenditure required to address the security of supply of the network; and
- non-demand expenditure required to address the maintenance of reliability and quality of supply of the network.

An overview of the historical and forecast expenditure is shown in figure 4.1.

Figure 4.1 Augmentation direct capital expenditure ($ million, 2015)



Source: Powercor

The profile above shows that augmentation expenditure fell over the latter part of the 2011–2015 regulatory control period. This was a lagged impact of the Global Financial Crisis (**GFC**) as expected demand did not increase at the expected rate. This allowed Powercor to prudently defer some planned augmentation projects.

While demand is slowly starting to increase closer to the expected rate, it is forecast to increase in localised areas of the Powercor network over the 2016–2020 regulatory control period, in particular:

- demand growth from increase in population, notably in the western suburbs of Melbourne, Geelong and the Surf Coast region; and
- demand growth from expansion in the dairy industry and increased irrigation needs for farming, principally in the southern areas near Warrnambool and northern areas along the Murray River.

Powercor's customers support the increase in capacity of its network to meet load growth. At the regional stakeholder engagement forums, Powercor's customers strongly supported investment in the local area to increase network capacity. In response to the Directions and Priorities consultation, the United Dairyfarmers of Victoria noted that:[35]

> *Whilst cost is a major issue for dairyfarmers, reliability and capacity of power supply is also a key problem for farmers in many regional areas.*
>
> …

[35] United Dairyfarmers of Victoria, *CitiPower and Powercor Australia Directions and Priorities Consultation Paper*, 5 November 2014, p. 3. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/21.UDV-5-November-2014.pdf.

> *The dairy industry supports the intention for 'upgrades of transformers to meet load growth in agricultural areas' as highlighted in the Directions and Priorities Consultation Paper…*

Similarly, the Mildura Development Corporation (**MDC**) noted that: [36]

> *MDC notes that there is considerable interest in developing large scale agricultural and horticultural factories as well as solar and biomass facilities in the Mildura region, with high energy use and demand.*
>
> *A limiting factor however is local power supply. For example, if a number of agricultural processors/ manufacturers or solar plant companies wanted to set up all at once in the Mildura region, there would likely be difficulty in meeting capacity.*

In addition to the localised growth in demand, the other key factors underpinning the need for an increase in augmentation capital expenditure are:

- costs associated with addressing a constraint at a transmission connection point, notably where the prudent solution involves associated distributor expenditure; and
- installation of voltage regulating equipment to ensure voltage levels are managed to meet the requirements of customers and associated regulations.

4.2 Background information

This section describes Powercor's methodology for forecasting augmentation capital expenditure.

4.2.1 Key drivers for expenditure

Augmentation expenditure is generally driven by an increase in peak demand, which may result in a shortage of capacity for the network assets, as determined by the planning policies of Powercor.

However, augmentation expenditure may also be driven by non-demand factors such as delivering security of supply to a different planning standard if the requirements of a Regulatory Test or Regulatory Investment Test for Distribution (**RIT–D**) have been met; or ensuring quality of supply to maintain voltage or fault levels within the thresholds required by the regulations or equipment design.

At times, augmentation expenditure may be driven by both demand and non-demand factors. For example, the forecast increase in demand on a sub-transmission line may also result in voltage levels being forecast to exceed the allowable threshold. In such cases, the expenditure will be categorised as demand driven as that is the primary driver of the augmentation.

Similarly, if a single customer is connecting a new or additional load, then the augmentation required to supply that customer will be categorised as connection and customer driven works capital expenditure. The driver in this case is the connection to the single customer.

4.2.2 Network planning standards

In general there are two different approaches to network planning.

- **Deterministic planning standards-**this approach involves specifying the amount of redundancy that must be built into the network to avoid supply outages. The level of redundancy is specified

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[36] Mildura Development Corporation, Submission – CitiPower and Powercor Australia Directions and Priorities Consultation Paper, 3 November 2014, p. 5. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/19.Mildura-Development-Association-3-November-2014.pdf.

in N-x terms, where 'x' is the number of network elements that could fail without electricity supply being lost. For example: N-1 means that electricity supply will not be disrupted if one element of the network fails. A strict use of this approach may lead to inefficient network investment as resilience is built into the network irrespective of the cost of the likely interruption to the network customers, or use of alternative options.

- **Probabilistic planning approach**-the deterministic N-x criterion is relaxed under this approach, and simulation studies are undertaken to assess the amount of energy that would not be supplied if an element of the network is out of service. As such, the consideration of energy not served may lead to the deferral of projects that would otherwise be undertaken using a deterministic approach. This is because:
  - under a probabilistic approach, there are conditions under which all the load cannot be supplied with a network element out of service (hence the N-1 criterion is not met); however
  - the actual load at risk may be very small when considering the probability of a forced outage of a particular element of the sub-transmission network.

Powercor adopts a probabilistic approach to planning its augmentations. The probabilistic planning approach involves estimating the probability of an outage occurring within the peak loading season, and weighting the costs of such an occurrence by its probability to assess:

- the expected cost that will be incurred if no action is taken to address an emerging constraint; and therefore
- whether it is economic to augment the network capacity to reduce expected supply interruptions.

The quantity and value of energy at risk (which is discussed in section 4.2.3) is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints; and
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under conditions of extreme loading. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower unserved energy.

This approach provides a reasonable estimate of the expected net present value to consumers of network augmentation for planning purposes. However, implicit in its use is acceptance of the risk that there may be circumstances (such as the loss of a transformer at a zone substation during a period of high demand) when the available network capacity will be insufficient to meet actual demand and significant load shedding could be required. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard to:

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes;
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand, and catastrophic equipment failure leading to extended periods of plant non-availability; and

- the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.

4.2.3 Forecasting methodology

Powercor has undertaken a bottom-up build of its augmentation expenditure forecasts, factoring in any synergies between replacement and augmentation projects. The output of this process is then verified by assessing the reasonableness of the outcomes against the forecast key network risks metrics labelled Load Indices and Health Indices.

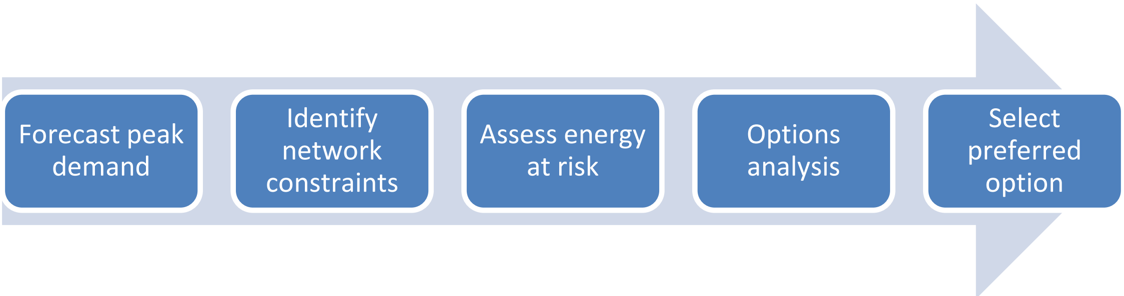
The methodology for forecasting the expenditure depends on the driver for the augmentation, namely if it is demand or non-demand driven.

Demand driven forecasts

For augmentations that are driven by increasing demand on the distribution network, Powercor has undertaken the steps outlined below. This process is consistent with the methodology that is set out in the Distribution Annual Planning Report (**DAPR**) published each year by Powercor.

The steps undertaken in forecasting augmentation capital expenditure is shown in figure 4.2. These are further discussed below.

Figure 4.2 Process to forecast augmentation capital expenditure



Source: Powercor

It is noted that constraints at the transmission connection points can also lead to requirements to augment the distribution network. The transmission connection assets are located within terminal stations, which are owned, operated, and maintained by the transmission asset owner, generally AusNet Services. The methodology for identifying those constraints is set out in the Transmission Connection Planning Report (**TCPR**) which is prepared and published annually by the five Victorian distributors.

Where a transmission connection asset constraint is identified, a Regulatory Test for Transmission (**RIT-T**) is undertaken to determine the preferred option to address that constraint, which is the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market. Such a test would generally be conducted jointly with the Australian Energy Market Operator (**AEMO**), which has responsibility for planning the Victorian shared transmission network.

Step 1: Forecast peak demand

The detailed process for forecasting peak demand for a network asset is set out in Appendix C. The forecasting and planning processes take into account a number of factors including statistical temperature forecasts, new connections, usage patterns and economic factors to estimate the required capacity of the network. At a high level, the forecasting process consists of:

- top–down independent econometric forecasts at the terminal station using the regional models prepared by the Centre for International Economics (**CIE**), which is consistent with the best practice methodology described by ACIL Allen in their 2013 report to **AEMO** for connection point forecasting;[37]
- bottom-up forecasts for demand at high voltage (**HV**) feeder and each zone substation, taking into account information about customer connections and embedded generators, which has been reconciled to the top-down CIE forecasts; and
- the reconciled zone-substation forecasts have been used to model forecasts of maximum demand on each sub-transmission line using the powerflow analysis tool called Power System Simulator for Engineering (**PSS/E**).

As peak demand in Powercor is very temperature dependent, the actual peak demand values are normalised in accordance with the relevant temperatures experienced across any given summer loading period. The correction enables the underlying year-by-year peak demand growth to be estimated, which is used in making future forecasts and investment decisions.

The temperature correction is used to determine the '50th percentile maximum demand'. The 50th percentile demand represents the peak demand on the basis of a normal season (summer and winter). For summer, it relates to a maximum average temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50 per cent probability of being higher than the 50th percentile demand forecast. The 50th percentile forecast can therefore be considered to be a forecast of the 'most-likely' level of demand, bearing in mind that actual demand will vary depending on temperature, and other variables such as the day of the week. It is often referred to as 50 per cent probability of exceedance (**50% PoE**).

For the purposes of the regulatory proposal, Powercor has also forecast peak demand at 10 per cent PoE, to prepare contingency plans for maximum demand during periods of very high or extreme temperatures.

It is also noted that in preparing the augmentation expenditure forecasts, Powercor has used the demand forecast at each level of the network (i.e. zone substation, sub-transmission lines, HV feeders) to determine the future requirements. The sub-transmission lines and HV feeder forecasts are derived from the zone substation load forecasts, and these are provided in template 5.4 of the Reset RIN.

Step 2: Identify constraints on network assets

Under the probabilistic planning approach, Powercor assesses and values the amount of load and energy that would not be supplied if an element of the network is out of service.

Take for example a zone substation. In this case, **energy at risk** is defined as:

> *The amount of energy that would not be supplied from a zone substation if a major outage of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.6 months and no other mitigation action is taken.*

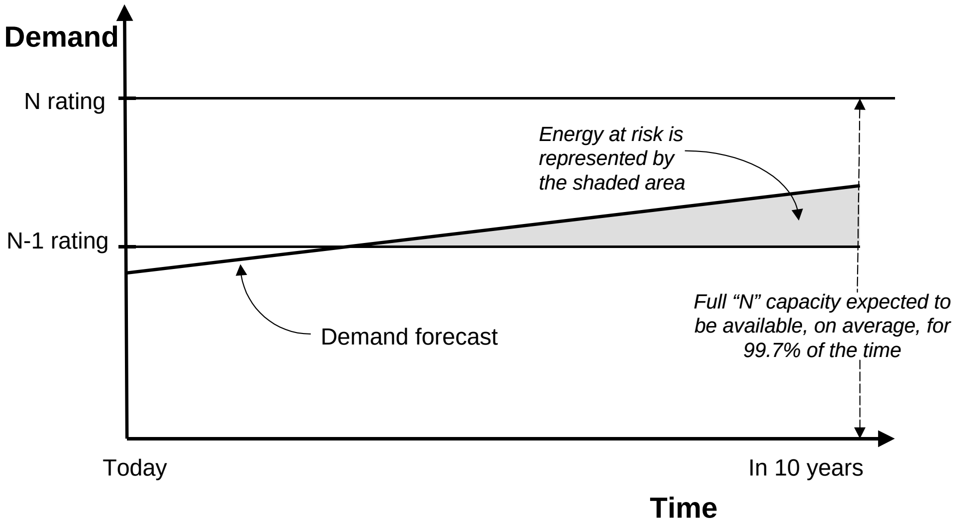
This statistic provides an indication of magnitude of loss of load that would arise in the unlikely event of a major outage of a transformer without taking into account planned augmentation or

[37] ACIL Allen Consulting, *Connection point forecasting – a nationally consistent methodology for forecasting maximum electricity demand*, Report to Australian Energy Market Operator, 26 June 2013.

operational action, such as load transfers to other supply points, to mitigate the impact of the outage.

The capability of a zone substation with one transformer out of service is referred to as its ‘N minus 1’ rating. The capability of the station with all transformers in service is referred to as its ‘N’ rating. The relationship between the N and N-1 ratings of a station and the energy at risk is depicted in figure 4.3 below.

Figure 4.3 Relationship between N, N-1 rating and energy at risk



Source: Powercor, *Distribution Annual Planning Report*, December 2014, p. 24.

Note that:

- under normal operating conditions, there will typically be more than adequate zone substation capacity to supply all demand; and
- the probability of prolonged outages of a zone substation transformer leading to load interruption is typically very low.

Step 3: Assess energy at risk against risk thresholds

The amount of energy at risk, as determined by step 2, is compared against Powercor’s internal policy to determine whether the energy at risk is sufficient to trigger a review of the network constraint.

An extract of the planning policy from the attached *Network Augmentation Planning Policy & Guidelines* is provided in table 4.1.

Table 4.1 Planning policy overview

Asset			Planning Criteria Trigger to Review Project Risks					
Type	Format	Section	Load Magnitude	Nominal Security Standard	Customer Interruption Time	Load Control Scheme	Maximum Load* as % of Rating	Maximum Time over Firm rating, Hours
Sub-transmission lines	Radial Overhead Line (Rural)	3.3.1.1	<20MVA	N	Best Practice	N/A	110	80
	Looped Line (Rural and Urban)	3.3.1.2	>20MVA	N-1	<1 minute	^Plant Protection	120	120
	Meshed Cable (CBD)	3.3.1.3	Any	N-1	<1 minute	N/A	120	120
	Meshed Cable Enhanced Security (CBD)	3.3.1.4	Any	N-2 after 30 minute switching	<1 minute	N/A	120	120
Sub transmission zone substations	Single Transformer Zone Substation (Rural)	3.3.2.1	<15MVA	N	Best Practice	N/A	100	0
	Multiple Transformer Banked Zone Substation (Rural)	3.3.2.2	15-20MVA	N-1	<4 hours	N/A	110	120
	Multiple Transformer Switched Zone Substation (Rural and Urban)	3.3.2.3	>15MVA	N-1	<1 minute	^Plant Protection	110	120
	CBD Zone Substations	3.3.2.3	>15MVA	N-1	<1 minute	N/A	100	0
Distribution lines	Radial Line (Rural Short & Rural Long)	4.2.1	Any	N	Best Practice	N/A	100	0
	Looped Line (Rural Long)	4.2.2	Any	N	Best Practice	N/A	80	0
	Looped Line (Urban & Rural Short)	4.2.3	Any	N	Best Practice	N/A	67	0
	Looped Line (Urban - CitiPower)	4.2.3	Any	N	Best Practice	N/A	67	0
	CBD Cable	4.2.4	Any	N	Best Practice	All in group except 1	100	0
						1 x standby	0	0
	SWER	4.2.5	<125kVA	N	Best Practice	N/A	125	0
Trans lines and Zone	Economic Criteria	>$1M Project value	The Annualised Cost of the Capital Project is less than the reduction in Annual Value of Expected Energy at Risk					

Source: Powercor, *Network Augmentation Planning Policy & Guidelines*.

Step 4: Options analysis

Where the energy at risk is sufficient to trigger a review of the network constraints, as determined by step 3, then Powercor assesses a range of options to address the network constraint.

For smaller augmentation projects, Powercor conducts a detailed investigation into possible network and non-network solutions to address the network constraint. Further discussion of non-network solutions is contained in section 4.2.4.

For large augmentation projects over $5 million that are subject to a RIT-D, Powercor undertakes a detailed assessment process to determine the economic efficiency of different investment options, including non-network solutions.

To determine the economically optimal level and configuration of distribution capacity (and hence the supply reliability that will be delivered to customers) for the purposes of the RIT-D, it is necessary to place a value on supply reliability from the customer's perspective.

Estimating the marginal value to customers of reliability is inherently difficult, and ultimately requires the application of some judgement. Therefore, Powercor relies upon surveys undertaken by the AEMO to establish the VCR. For the purposes of the Regulatory Proposal, Powercor has used the values for Victoria set out in AEMO's *Value of Customer Reliability Review* published in September 2014,[38] as set out in table 4.2.

Table 4.2 AEMO's value of customer reliability

Sector	VCRs for 2013 ($/kWh)	VCR for 2014 ($/kWh)
Residential (Victoria)	27.19	24.76
Commercial (NEM)	113.05	44.72
Agricultural (NEM)	147.76	47.67
Industrial (NEM)	44.93	44.06[39]
Composite- all sectors		39.50

Source: AEMO

The values have been applied in a manner consistent with AEMO *Application guidelines* published in December 2014.[40]

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.

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38 AEMO, *Value of Customer Reliability Review*, Final Report, September 2014.

39 Excludes industrial customers that are directly connected to the transmission network.

40 AEMO, Value of customer reliability—application guide, final report, December 2014. Available from: http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review

Step 5: Selection of preferred option

For projects subject to RIT-D, Powercor prepares a list which identifies all credible options to address the identified need, which includes both network and non-network solutions. Except where the options are to address a reliability issue, market benefits and costs of each option will be quantified. The credible option with the highest net economic benefit will receive the highest ranking and be the preferred option. Cost estimates have been obtained from a supplier for each material augmentation project, and where the projects have already commenced, detailed cost estimates have been utilised that have been through Powercor's robust internal governance process.

For other augmentation projects, the most cost effective solution that also satisfies the risk based triggers in the Planning Guidelines is chosen as the preferred option. Detailed cost estimates have been derived from historical project costs for similar projects, where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

Non-demand driven augmentation expenditure

As noted previously, augmentation expenditure may also be driven by non-demand factors such as:

- ensuring the security of supply of the network; and
- maintaining reliability and quality of supply of the network.

The quality of supply issues in the network are determined during the process to identify possible demand-driven constraints, as set out above. That is, Powercor considers whether the forecast changes in demand, both changes in load growth and embedded generation, may result in the prospective fault current or voltage levels being outside the allowable limits.

In terms of security of supply, where increases in demand are expected on an asset, Powercor considers improving the security of supply particularly where there is:

- a single transformer at a zone substation;
- radial sub-transmission lines; and
- banked configuration of the transformers.

The use of a single transformer or a radial sub-transmission line generally occurs in rural areas of the network, typically with low demand. Improving the security of supply adds redundancy into the network to enable Powercor to continue to provide electricity in the event of a major failure of a network asset.

When major demand related augmentation is planned at a zone substation, Powercor considers improving the switching configuration such that supply can be maintained without any intermittent loss of supply in the event of a transformer outage. For example, this can be achieved by isolating the faulty transformer automatically. This zone substation configuration is referred to as 'fully switched', as opposed to a banked configuration. A fully switched station is the current Powercor standard for new zone substations, and is considered standard industry practice.

Where there is no augmentation project planned for forecast changes in demand for a particular network asset where quality or security of supply issues have been identified, then Powercor considers options to address the non-demand driven identified need.

Powercor has undertaken a bottom-up build of the costs to address any forecast quality or security of supply issues on the network. Where the cost of the most expensive credible option is more than

$5 million, Powercor has applied the RIT-D process to determine the preferred option to address the quality or security of supply issue.

4.2.4 Non-network alternatives

This section discusses the consideration, and use, of non-network alternatives.

Consideration of non-network alternatives

Non-network solutions are an important component for the effective operation of the network and can involve either the reduction of customer electricity demand at peak times or the direct supply of electricity at the distribution level.

Effective and prudent use of non-network solutions can reduce the need for network augmentation and associated maintenance costs resulting in lower electricity bills for consumers.

There are a range of non-network solutions that can be used by electricity networks including:

- automated, contracted or voluntary demand management;
- shifting appliance or equipment use from peak periods to non-peak periods (eg: controlled load (off-peak) water heating);
- operating appliances at lower power demand for short periods (eg: air conditioner load control);
- use of energy efficiency programs;
- use of pricing structures, such as Time of Use tariffs, to change consumer consumption patterns;
- voluntary load curtailment by customers, such as in response to a request to reduce electricity usage;
- voluntary load shedding and disconnection of non-critical loads by customers;
- power factor correction of customer equipment;
- operation of embedded generators using conventional or renewable fuel sources;
- use of stand-by generators to support load; and
- storage devices such as batteries that can store energy in times of reduced demand and convert back to electricity at times of peak demand.

When a network constraint is identified, a review of options that includes both reducing demand and increasing capacity is initiated. The goal is to find the most efficient and prudent solution. This may be a non-network solution.

The framework and process by which Powercor engages with non-network providers is set out in the Demand Side Engagement Strategy.[41] Importantly, Powercor maintains a demand-side register for parties to notify their interest in being advised of developments relating to the planning and expansion of the networks. Powercor will use this register not only to consult with interested parties, but also to determine the level of interest and ability to participate in the process for the development of non-network options.

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41 CitiPower Pty /Powercor Australia Ltd, *Demand side engagement strategy*, 31 August 2013.

The DAPR also provides preliminary information on potential opportunities to prospective proponents of non-network solutions at zone substations or on sub-transmission lines where remedial action may be required.

Use of non-network alternatives

Powercor has undertaken a range of demand management activities in the current regulatory control period, including:

- a trial with an industrial customer for automated demand management using customer plant management system with upgrades to control demand within certain limits;
- a program with a demand-side aggregator to analyse market and suitability of contracted demand management in an urban industrial area;
- portable generator trials at the Charlton (**CTN**) and Boundary Bend (**BBD**) zone substations involving line load sensing and remote embedded generator control,;
- trial installation of a battery in the Ballarat south area to meet maximum loads to a constrained rural long 22kV feeder. The battery will store energy from the grid, and be utilised to:
    - defer augmentation of a feeder by supplying energy at peak times to customers that would otherwise be constrained;
    - provide voltage support on the network; and
    - for islanding network purposes, where the feeder can be segmented during a fault and supply can be maintained to some customers.

A complete list of the non-network alternative projects that Powercor has undertaken during the current regulatory control period, and those that it has selected to commence or continue during the 2016–2020 regulatory control period, are set out the *Non-network alternatives* attachment.

4.2.5 Use of Load Indices

To enhance the use of probabilistic planning, Powercor had collaborated with EA Technology to develop Load Indices. The indices are intended to provide a high level indication of demand-related network risk and performance. They are also used to assess the reasonableness of bottom-up augmentation expenditure forecasts.

Background to load index

Ofgem introduced load indices into the electricity distribution regulatory framework in the United Kingdom, together with health indices. These were designed by Ofgem to tie specific price control network investment to specific in-period risk reduction associated with the condition and loading of assets. The metrics link the longer-term key network risk metrics to a measurable deliverable within the Ofgem price control.[42]

The load index measures applied in the UK have been adapted by Powercor to accommodate the greater spread of load conditions on its network, reflecting the use of probabilistic planning standards rather than deterministic standards.

[42] Ofgem, *Strategy consultation for the RIIO-ED1 electricity distribution price control – reliability and safety*, Supplementary annex to RIIO ED1 overview paper, 28 September 2012, p. 8, paragraph 2.6. Available from https://www.ofgem.gov.uk/ofgem-publications/47145/riioed1sconreliabilitysafety.pdf.

The Load Index, which is a measure of asset utilisation, is generated from two factors;

- demand driver – measure of maximum demand relative to firm capacity; and
- duration and energy driver – measure of hours or energy at risk.

The Load Indices have been developed to cover a range of conditions, and are placed on a scale from 1 to 10. An index of one indicates that there is no load at risk under peak load conditions. There are several bands for increasing times over firm capacity (N-1 rating). An index of nine or ten indicates that the load is approaching or even exceeding the N capacity, and that load shedding is likely to occur, resulting in significant loss of supply and/or time required to restore supply.

The bandings are intended to provide sufficient breadth and sufficient discrimination to both visualise/communicate the overall level of load, and to show the effects of modest load increases over the next few years. The bandings are shown in table 4.3.

Table 4.3 Load Index bands

Load Index	Condition	Load%		Hrs % Firm Capacity	
		>Minimum	≤ Maximum	>Minimum	≤ Maximum
1	N-1	0	90	N/A	N/A
2	N-1	90	100	N/A	N/A
3	N-1	100	110	N/A	N/A
4	N-1	110	…	N/A	100
5	N-1	110	…	N/A	250
6	N-1	110	…	N/A	500
7	N-1	110	…	N/A	750
8	N-1	110	…	750	7500
9	N	90	100	N/A	N/A
10	N	100		N/A	N/A

Source: Powercor

Powercor uses the load indices for zone substations and sub-transmission lines.

The load indices are straightforward to apply. Take for example the Waurn Ponds zone substation. Given the peak demand forecasts contained in the 2014 DAPR, Powercor has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk.

Table 4.4 Estimated energy at risk at Waurn Ponds (WPD) zone substation

WPD	2015	2016	2017	2018	2019	2020
Summer demand (MVA)	85.2	94.3	100.5	105.1	109.9	114.9
Summer overload (%)	40.2	55.1	65.3	72.8	80.7	89.0
Annual energy at risk (MWh)	546	1989	2672	3455	4252	5026
Annual hours at risk (hrs)	131	369	439	524	599	677

Source: Powercor, *Distribution Annual Planning Report*, December 2014, p. 59.

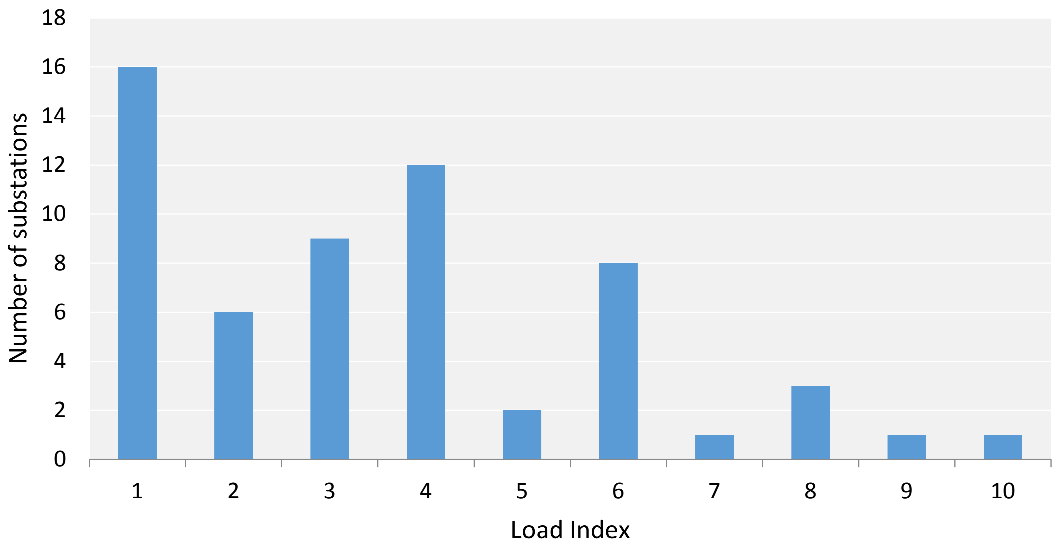
Table 4.4 shows that in 2015, the summer overload above N-1 is forecast to be 40 per cent, and with 131 hours at risk. This indicates a load index of five. Without augmentation of the zone substation, the summer overload rises to 89 per cent in 2020 with 677 hours at risk — a load index of seven.

It is noted that for a single transformer substation or radial sub-transmission line, the firm capacity is taken as the transfer capacity. As the time over firm capacity is not supplied for this definition, where the maximum demand exceeds the transfer capacity it is assumed that the number of hours over firm capacity is >750, so the asset is classified with a load index of eight.

Checking the reasonableness of expenditure forecast

Powercor's expected load index profile at the start of the 2016–2020 regulatory control period is shown in figure 4.4. This provides a visual tool to understand at a high level the loading and energy at risk on major assets.

Figure 4.4 Load index of Powercor zone substations in 2016



Source: Powercor

Similar to the HI approach, as zone substations move into the seven and higher categories, plans are required to manage or alleviate the loading constraints. The profile shows that Powercor has several zone substations with a load index above seven, including one zone substation with an index of nine and one at ten. The load indices indicate that there is significant load at risk, and it is clear that Powercor needs to augment the network.

The demand forecasts can be used to generate load index profile predictions for future years to check the appropriateness of the expenditure forecasts. The profiles are compared using a ‘do nothing’ approach, against the forecast augmentation projects to ensure that, over the forecast period, the load index profile for the total transformer fleet is appropriately managed.

A load index profile similar at the end of the forecast period to the current profile infers that:

- no changes to network planning processes are required over the forecast period;
- no backlog of pending augmentations at the end of the forecast period; and
- no significant reduction in utilisation is forecast.

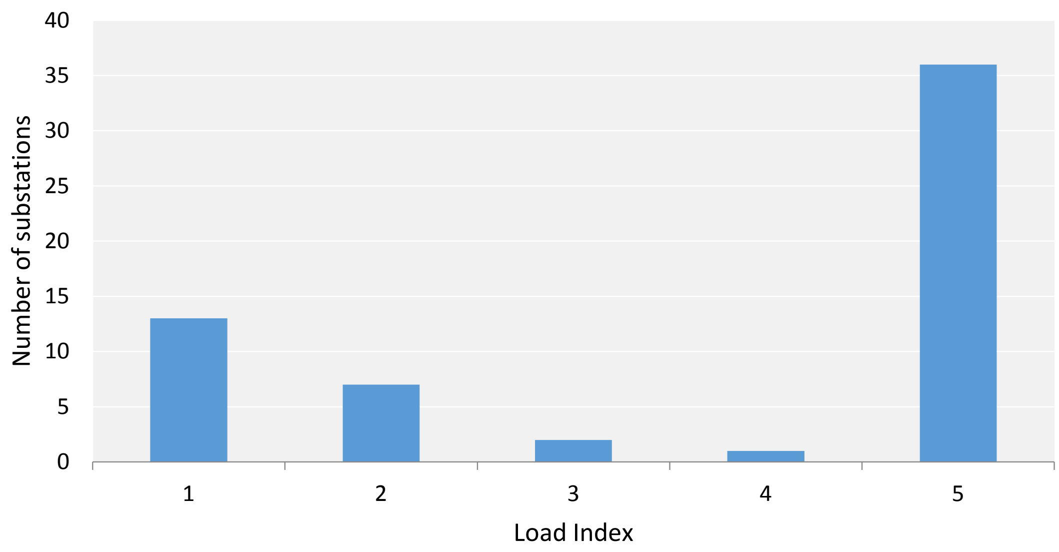
If the load index profile deteriorates over the forecast period, then it would suggest that a step up in expenditure is required.

Comparison with overseas

Powercor adapted the UK load index measures to accommodate the greater spread of load conditions on the network, reflecting the use of probabilistic planning standards rather than deterministic standards.

If the scale that is applied in the United Kingdom was applied, then it would indicate that Powercor has a large number of zone substations at the top of the scale.

Figure 4.5 2014 Load index profile at the start of 2016 using UK scale



Source: Powercor

Powercor understands that distributors in the United Kingdom are required to address assets with a load index above two. This would encompass the majority of Powercor’s assets.

4.2.6 Comparison of unit rates

This section further describes the unit rates that Powercor have used in estimating the costs of the proposed projects. It also discusses the unit costs contained in the Category Analysis RIN, which Powercor has not utilised in preparing its augmentation forecasts.

Calculation of unit rates

As noted above, the costs for large augmentation projects are based on estimates provided by a supplier to Powercor.

Comparison of unit rates is not appropriate

As discussed in the regulatory proposal, benchmarking of costs across distributors can only be appropriate when the following conditions hold:

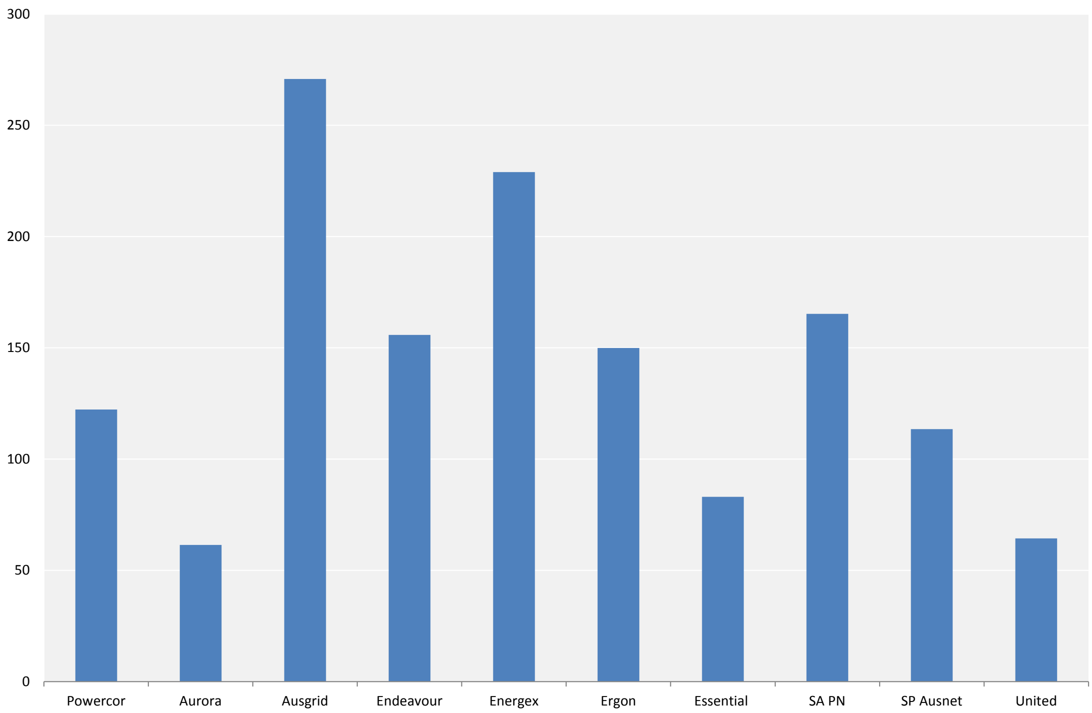
- consistent reporting and interpretations of costs;
- exogenous differences in operating environment are normalised; and
- costs reflect a representative and appropriate sample.

These conditions do not hold for the data for augmentations contained in the 2013 Category Analysis RIN, and therefore the AER should be cautious in using the data to inform any of its decisions for the Regulatory Proposal.

Example 1 – new zone substations

Take for example the category of new zone substations. The unit rate data shown in figure 4.6 represents the average cost over the period from 2009 to 2013, calculated by dividing the total expenditure by the total volumes over the period. Powercor's unit rate appears to be slightly below the average unit cost across all distributors.

Figure 4.6 Zone substations – new substations ($000/MVA, 2014)



Source: Category Analysis RIN, Powercor analysis
Note: distributors with no data have been excluded from the graph

However, the data is not comparable. Powercor installed one new zone substation at Gisborne during the relevant period, which is not a statistically significant sample size to draw a conclusion on average costs. In contrast, Endeavour Energy reported that it installed 40 new zone substations, however it appears from their data that they have included zone substations installed prior to the reporting period, as well as future zone substations to be completed in 2020/21.

The method to calculate the MVA added appears to differ between distributors. The nameplate rating relates to the ongoing capacity determined by the plant manufacturer, whereas the cyclic rating is the capacity of the transformer after jurisdictional planning standards, the cooling profile of the transformer and environmental conditions are taken into account. The cyclic rating of a transformer is higher than the nameplate rating. Powercor has used the nameplate rating to determine the Megavolt Ampere (**MVA**) added by each transformer, however it appears that other distributors have used the cyclic rating.

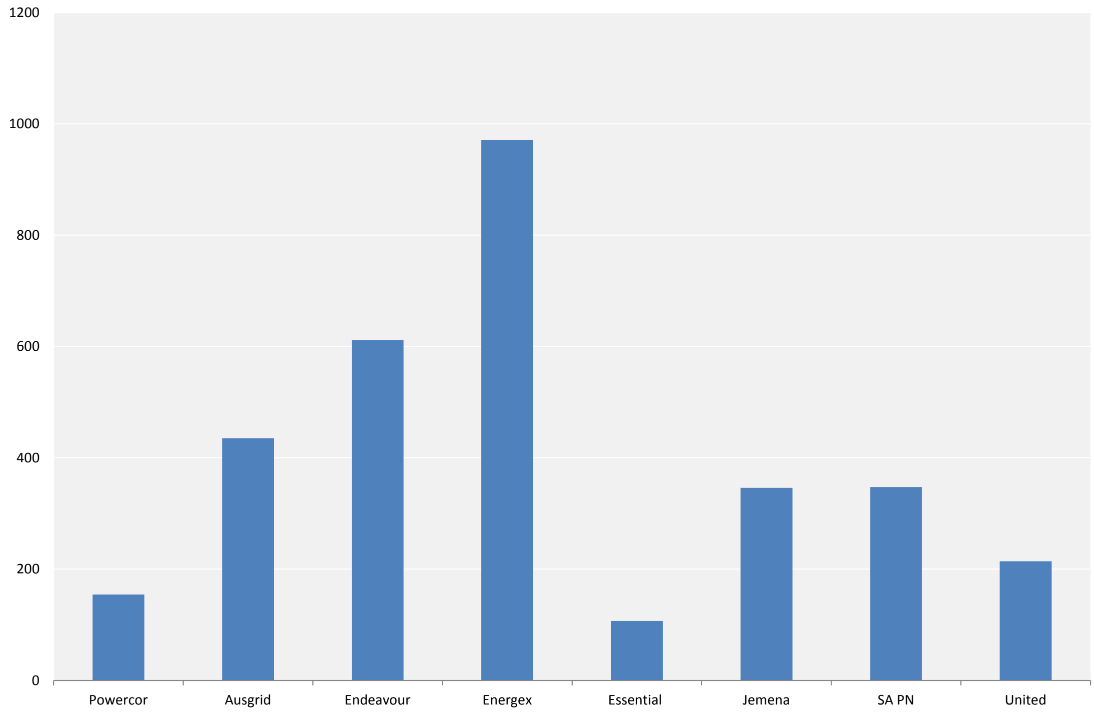
The costs incurred for each zone substation will also different. Zone substations in inner metropolitan areas are likely to be indoor using gas insulated switchgear, potentially with building amenity requirements, whereas regional and rural zone substations are likely to be outdoor and use less expensive plant and equipment. Some of the new zone substations contain only a single transformer, which may lead to higher costs per MVA given the fixed costs associated with a zone substation.

It is clear that distributors have interpreted the data requirements differently, there are different operating conditions, and in some cases the sample sizes are not large enough to determine unit costs. As a result, the data should not be relied upon for benchmarking purposes.

Example 2 – upgrade of overhead sub-transmission lines

The data is also not comparable for the upgrade of overhead sub-transmission lines. Figure 4.7 shows the unit rate data from the Category Analysis RIN.

Figure 4.7 Sub-transmission lines – upgraded overhead lines ($000/km)



Source: Category Analysis RIN, Powercor analysis
Note: distributors with no data have been excluded from the graph

The upgrade of an overhead line could involve:

- replacement of the conductor with a larger capacity conductor; or
- uprating of the sub-transmission line.

The uprating of a line involves increasing the clearance space between the conductor and other assets or ground, for the purpose of increasing the thermal rating of the line. This may involve, for example, moving a cross arm on a pole. The costs involved to uprate a line are far lower than replacing a conductor.

The average unit cost for upgrade per kilometre will vary significantly depending on the mix of projects undertaken by the distributor in the reporting period.

The highest number of projects undertaken by any distributor during the reporting period to upgrade a sub-transmission line is four. As a result, the sample size is not statistically significant to draw a conclusion on average unit costs.

Furthermore, removing outliers may also invalidate the average unit cost between distributors. It appears that Energex undertook one project involving the upgrade of a line within the reporting period, that was significant enough to pass the AER's materiality threshold. This one project involved upgrading around 11km of line for a cost of $10 million. The costs may be efficient given the unique characteristics of that project, and thus removing the outlier may artificially lower the average unit cost of upgrading a sub-transmission line.

It is clear that the data from the Category Analysis RIN cannot be used to draw conclusions relating to average unit costs for augmentation projects.

4.3 Historic spend

One of the key projects that Powercor delivered during the 2011–2015 regulatory control period was the construction of a new zone substation at Gisborne (**GSB**), together with new 22kV feeders and extension of the sub-transmission lines to serve the residential customer growth.

Powercor also installed new transformers at Boundary Bend (**BBD**), Stanhope (**SHP**), Wemen (**WMN**), Charlton (**CTN**) and Sunshine East (**SSE**) zone substations. New capacity banks were installed at Colac (**CLC**), Laverton North (**LVN**) and BBD zone substations to correct the power factor of the transformers and increase capacity.

New 66kV sub-transmission lines were built from BBD to Piambie to support agribusinesses, and from Waurn Ponds (**WPD**) to Torquay, initially operating at 22kV, to support local demand growth. Powercor also upgraded a number of sub-transmission lines supplying greater Geelong and the Bellarine Peninsula, and the lines from Ballarat terminal station (**BATS**) to Bacchus Marsh (**BMH**). The initial stage of the upgrade of the sub-transmission line from Bendigo terminal station (**BETS**) to CTN also commenced. Seven new feeders were also installed at Drysdale (**DDL**), Werribee (**WBE**), Melton (**MLN**), SSE and BTS.

Powercor also commissioned upgrades to the supply of the Geelong terminal station (**GTS**), BETS, and the Keilor terminal station (**KTS**) to manage risk until Deer Park terminal station (**DPTS**) is built.

Overall, Powercor is forecast to underspend its augmentation regulatory allowance in the 2011–2015 regulatory period by 56 per cent. The expenditure profile in Figure 4.1 shows the fall in expenditure during the latter part of the regulatory control period reflecting the lagged impact of the Global Financial Crisis (**GFC**).

The augmentations undertaken in the earlier part of the regulatory period were committed projects undertaken to address network constraints that had been identified prior to the GFC. However, demand did not continue to rise at the expected rate following the GFC, and as such Powercor was able to prudently defer some planned augmentation projects.

As forecast demand did not materialise as expected following the GFC, network augmentation was not triggered under Powercor's probabilistic planning approach in some areas of the network. For example, Powercor was able to efficiently defer the construction of a new Torquay (**TQY**) zone substation as well as defer the upgrade of two transformers at Geelong East (**GLE**) zone substation due to the later than forecast start of large residential developments in the Geelong area, such as the Armstrong Creek subdivision as shown in the box below.

Delay at Armstrong Creek

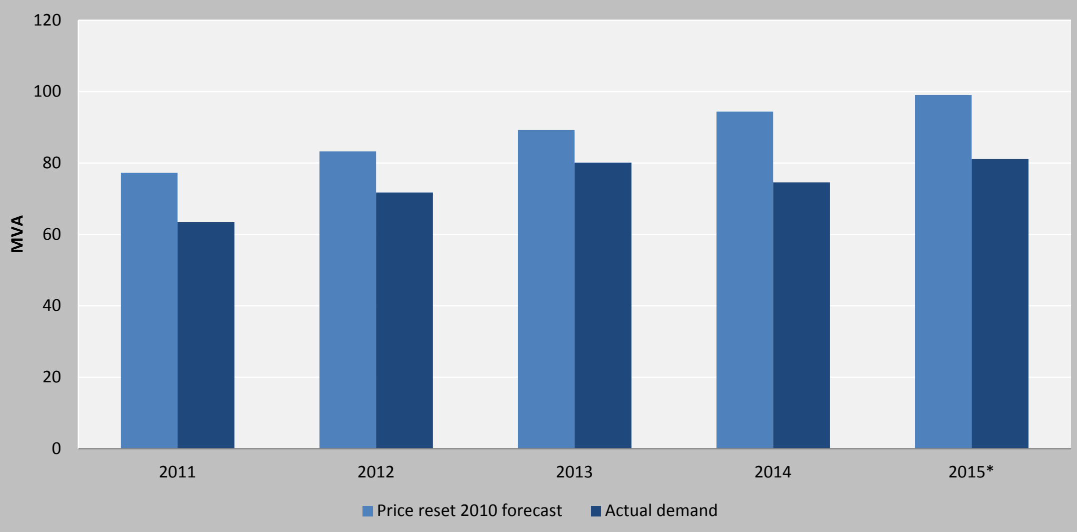
The Armstrong Creek growth area consists of 2,500 hectares of contiguous land and will provide housing for between 55,000 and 65,000 people. It will comprise of approximately 22,000 residential homes.[43]

The development, located in the corridor between Geelong and Torquay, was expected to commence in 2011. However, the project was delayed due to a number of factors. The delay has resulted in:

- lower than expected residential connections; and
- lower than expected peak demand.

The feeders serving the Armstrong Creek development will originate from the Waurn Ponds (**WPD**) zone substation. The forecast of peak demand in 2010 is shown in the figure below, together with the actual peak demand that has materialised.

Figure 4.8 Expected versus actual demand at Waurn Ponds zone substation



Source: Powercor
Note: 2015 observation on 3 January 2015. A higher maximum demand may be achieved during the year.

In the 2010 DAPR, Powercor forecast that by 2014, the annual hours at risk at WPD would be 215 hours if it did not undertake an augmentation. However, in the 2013 DAPR, Powercor expected

[43] City of Greater Geelong, Armstrong Creek – whole of growth area, webpage accessed 9 April 2015. Available from: http://www.geelongaustralia.com.au/armstrongcreek/armstrong/article/item/8cfafd49ea31e3f.aspx.

there to be only 80 hours at risk in 2014. The reduction in the annual hours at risk allowed Powercor to efficiently defer the commencement of the augmentation at WPD.

The Armstrong Creek development has now commenced.

A range of other smaller projects were also able to be deferred as a result of the lower than expected growth in peak demand, such as feeder projects, including Ballarat South (**BAS**) 31 and 33, and Ford North Shore (**FNS**) 31 and 33 22kV feeders.

Aside from the lower than expected peak demand, projects were deferred for other reasons. For example:

- delay of the Bendigo terminal station (**BETS**) to Charlton (**CTN**) 66 kV sub-transmission line upgrade as a result of a third party dispute relating to property rights; and
- Numurkah (**NKA**) to Cobram East (**CME**) 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.

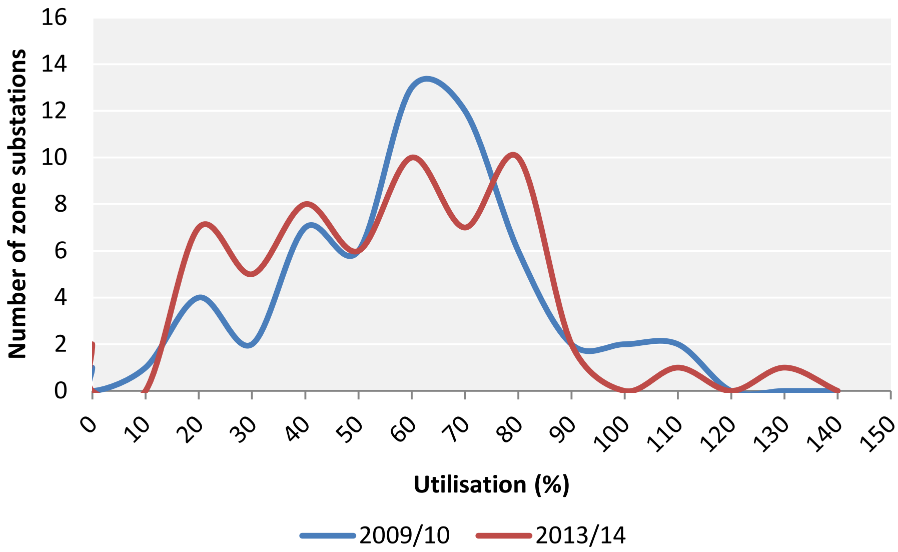
The changes in the network augmentation plans as a result of updates to forecast demand demonstrate that Powercor continues to prudently and efficiently augment its network in response to the latest information.

4.3.1 Efficiencies of past actual expenditure

The AER has considered the decreasing average utilisation levels at zone substations in the NSW draft determinations to suggest that there is excess capacity in their network that needs to be utilised ahead of additional augmentation investment.[44]

Powercor notes that its average utilisation has also fallen over the period from 2008/09 to 2012/13 in its zone substations, from 75 per cent to 69 per cent.

Figure 4.9 Powercor utilisation profile for zone substations



[44] For example, see AER, *Draft decision Ausgrid distribution determination 2015–16 to 2018–19*, Attachment 6: Capital Expenditure, November 2014, p.6-38.

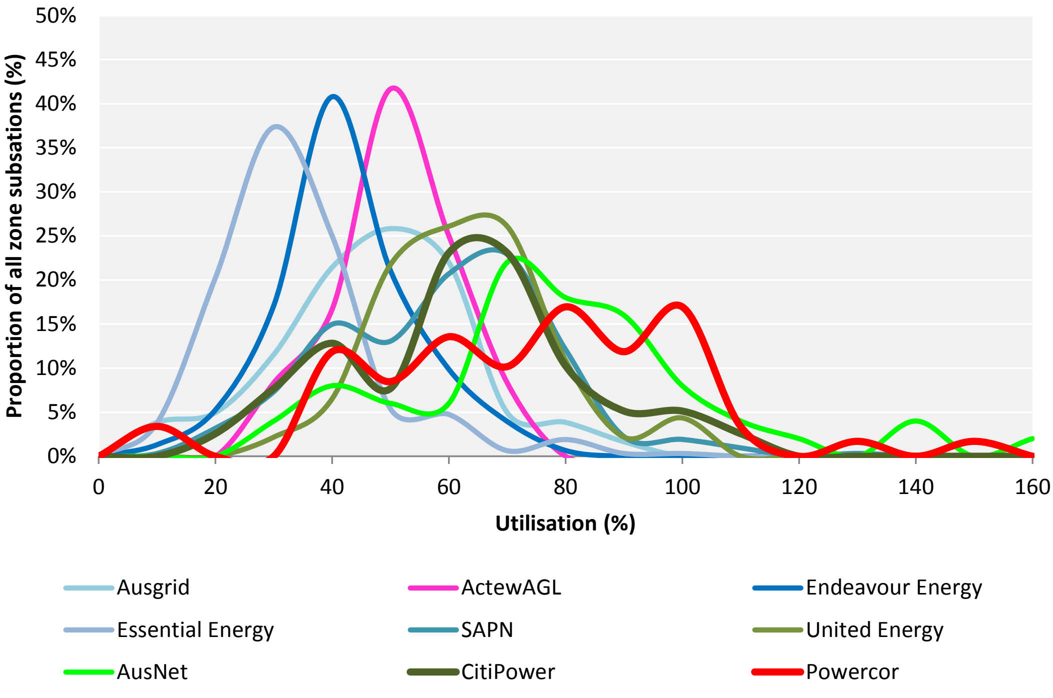
Source: Augex model, Jacobs analysis

The fall in average utilisation is not a particular concern for Powercor, as augmentation is only undertaken to address a particular localised constraint. For example, Powercor has constructed a new zone substation in Gisborne in the intervening period to address peak demand constraints in that area, as capacity from other zone substations was not able to be utilised to address that constraint. The additional zone substation may have lowered the average utilisation, but this does not suggest that there is now excess network capacity.

The primary concern for Powercor is managing the zone substations that have a very high utilisation rate. It is noteworthy that the number of zone substations with a peak demand utilisation rate over 90 per cent increased from 12 in 2008/09 to 14 in 2012/13. As a result, Powercor is managing additional risk on its network.

The utilisation profiles, however, demonstrate that the probabilistic planning approach used in Victoria compared to the deterministic planning standard that was then used in the northern states results in higher asset utilisation on average. Figure 4.10 shows the utilisation profiles across distributors in NSW, Queensland, Victoria and South Australia normalised for the number of zone substations.

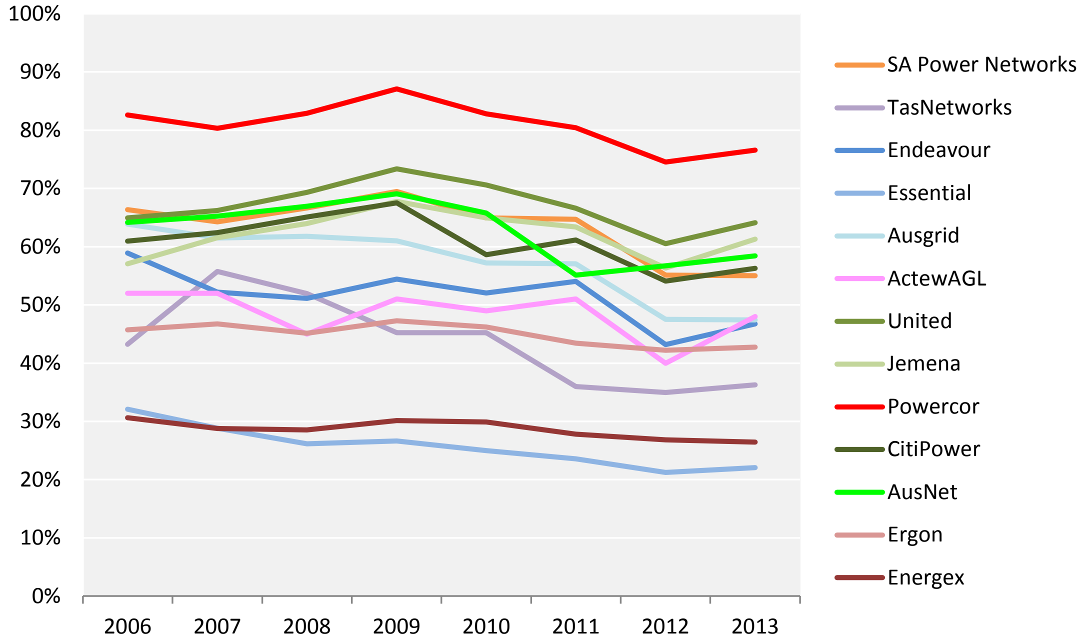
Figure 4.10 Normalised zone substation utilisation 2012/13 for all distributors



Source: AER Category Analysis RIN, Jacobs analysis
Note: the data for SA Power Networks relates to 2013/14

Furthermore, data from the Economic Benchmarking RIN suggests that Powercor has the highest utilisation of any distributor in the NEM, as shown in figure 4.11. Utilisation is measured as the sum of non-coincident max demand at the zone substation level divided by the sum of zone substation thermal capacity.

Figure 4.11 Utilisation of the network



Source: AER Economic Benchmarking RIN DQS04, Powercor analysis

4.4 Forecast spend

Powercor requires a 93 per cent increase in augmentation expenditure compared to its actual spend during the 2011–2015 regulatory control period. The large step up includes the distribution works associated with DPTS which is a large once-off project that does not typically take place during a regulatory control period. The key factors underpinning the need for an increase in augmentation capital expenditure are:

- localised demand growth from growth in population, particularly in the western suburbs of Melbourne, Geelong and the Surf Coast region;
- demand growth from expansion in the dairy industry and increased irrigation needs for farming, particularly in the southern areas near Warrnambool and northern areas along the Murray River;
- costs associated with the DPTS to address a constraint at a transmission connection point supplying both Powercor and Jemena networks; and
- installation of voltage regulators to ensure the voltage levels do not exceed the thresholds required by the regulations or equipment.

Each of these drivers is discussed below.

Demand based growth

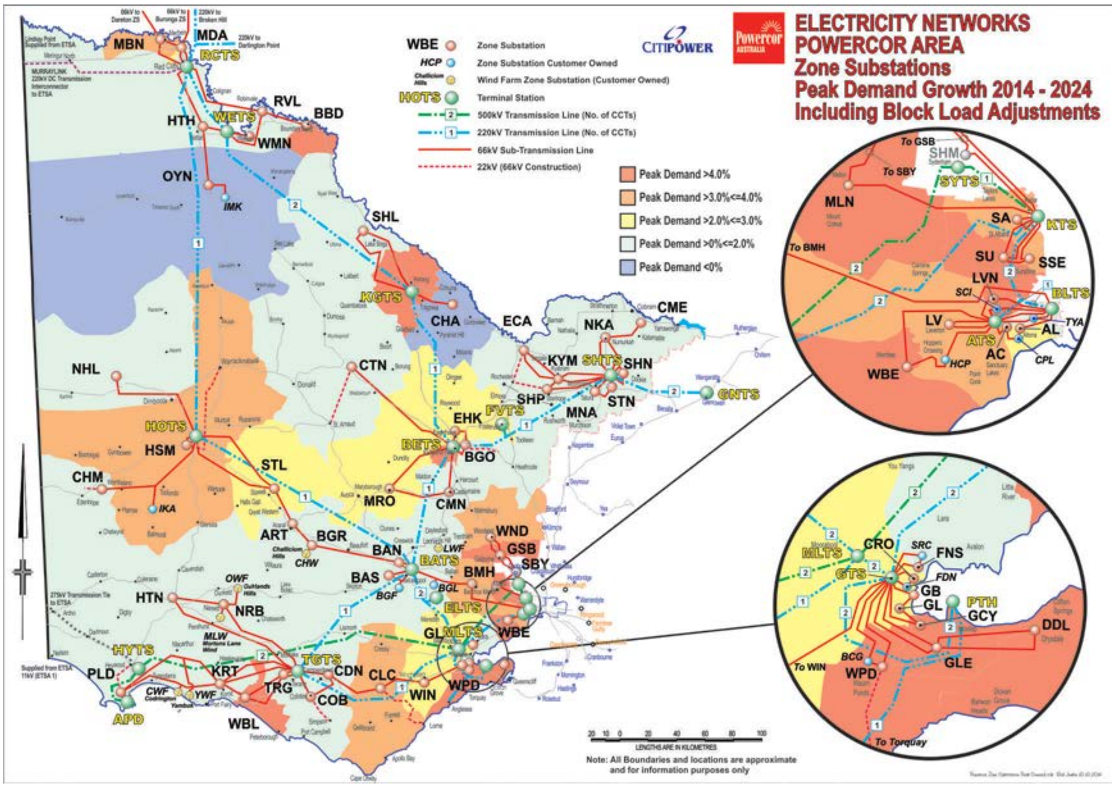
Expenditure required to continue to meet growing demand represents 80 per cent of augmentation expenditure. As discussed in Appendix C, Powercor expects that there will be stronger growth in particular regions, notably from:

- population growth in the western suburbs of Melbourne and the Geelong/Surf Coast region;
- dairy farming in the southern areas near Warrnambool and near the Murray River between Swan Hill and Cobram; and

- irrigation needs in rural areas, particularly along the Murray River from Mildura down beyond Boundary Bend.

The growth areas in Powercor's network, at the zone substation level, are shown in figure 4.12.

Figure 4.12 Powercor's forecasts of peak demand growth by zone substation



Source: Powercor

Powercor intends to undertake augmentation projects to address the localised increase in demand, including:

- construction of a new zone substation in Torquay (**TQY**) and two sub-transmission lines to serve the TQY from the Waurn Ponds (**WPD**) zone substation, and the upgrade of two transformers at the Geelong East (**GLE**) zone substation to support growth in the Geelong and Surf Coast regions; and
- installation of a new transformer in the Merbein (**MBN**) zone substation to support irrigation needs in the greater Mildura area.

In terms of addressing demand growth in the western suburbs, this will occur through the construction of the Truganina (**TNA**) zone substation, as part of the works to address the constraint at the Keilor Terminal Station. This is discussed in the case study further below.

The RIT-D framework will be used to assess all material augmentation initiatives triggered by increases in demand.

Checking the reasonableness of the forecasts

As noted above, Powercor is able to undertake a top-down check that its expenditure forecasts are reasonable, sustainable and will enable it to prudently and efficiently manage the network constraints by using the load index to generate profile predictions for future years.

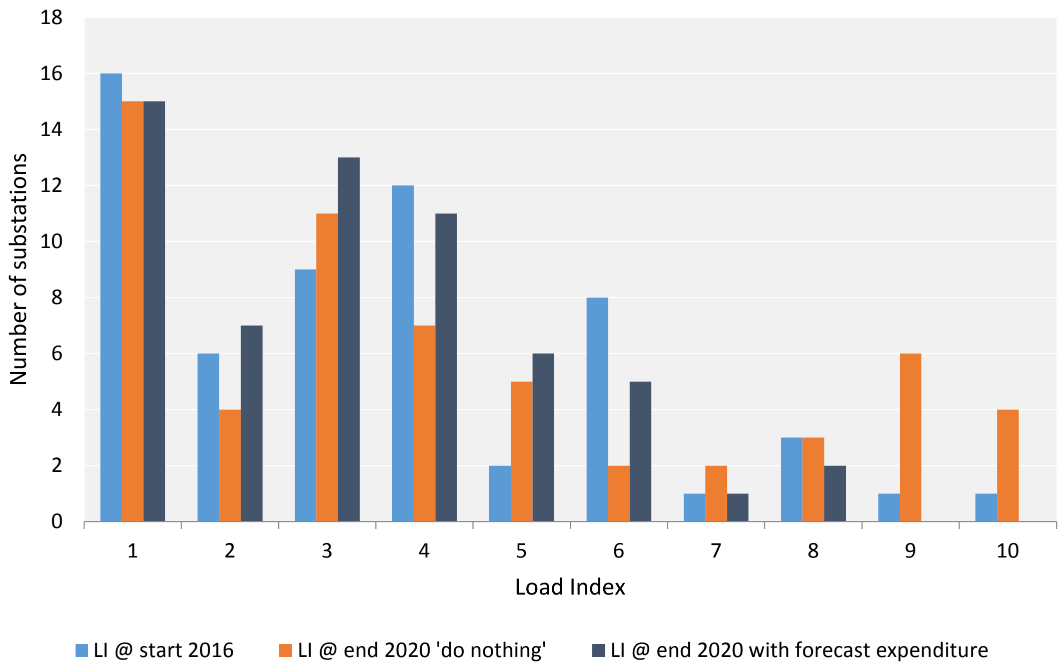
Powercor has created the load index profile at the start of the 2016–2020 regulatory control period and compared that to:

- the profile that would occur in the 'do nothing' scenario over the 2016–2020 regulatory control period; and
- the profile that would occur if it undertakes the investments set out in this regulatory proposal.

The comparison of these profiles allows Powercor to ensure at a top-down level that the network constraints at zone substations or on sub-transmission lines are being appropriately managed. This is particularly applied to that portion of the profile that is greater than or equal to seven.

Using transformers in zone substations, figure 4.13 shows that Powercor's forecast expenditure is reasonable as it is able to appropriately maintain the number of transformers with a load index of seven or above, as well as maintain the overall profile.

Figure 4.13 Load index at the end of 2020 with and without augmentation



Source: Powercor

In the 'do nothing' scenario, around 10 zone substations will be approaching or exceeding the normal capacity of the transformers at the time of peak demand, which may result in outages. With the proposed augmentation projects, no zone substation will be exposed to such risk.

Addressing the transmission level constraint

The largest augmentation project that Powercor will undertake during the 2016–2020 regulatory control period will be the distribution works relating to the construction of the Deer Park Terminal Station (**DPTS**) and building the new Truganina (**TNA**) zone substation for the purposes of addressing the constraint at the Keilor Terminal Station (**KTS**) and meeting demand from the growing suburbs of the outer west of Melbourne.

In June 2014, AEMO and Powercor together released a tender for the right to build, own and operate the DPTS. TransGrid has been informed that it is the preferred tenderer for the works.[45] Works on the terminal station are expected to commence in late 2015. The contract requires the DPTS to be operational by November 2017.

Some load that is currently being served out of KTS will be transferred to DPTS, thereby addressing the constraint at KTS, and securing supply for Powercor and Jemena customers served by KTS. This involves Powercor rearranging the sub-transmission lines so that Melton (**MLN**) and Sunshine (**SU**) zone substations will be taken off KTS and served by DPTS.

The new TNA zone substation will also be served from DPTS. Powercor will finalise design works for TNA in 2015, with construction commencing in 2016.

Case study: development of Deer Park terminal station

Powercor undertook a joint Regulatory Test with Jemena Electricity Networks and the Australian Energy Market Operator (**AEMO**) to address a system limitation at the Keilor Terminal Station (**KTS**), and on the sub-transmission lines from KTS that serves the Melton (**MTN**), Sunbury (**SBY**) and Sydenham (**SHM**) zone substations. SBY and SHM are zone substations for Jemena.

The final report was published on 1 May 2012 which recommended the construction of a new terminal station at Deer Park (**DPTS**).[46] The regulatory test demonstrates that the works are prudent and efficient and that the option selected maximises the net economic benefit to consumers. Other key elements of the report include:

- construction of 66kV sub-transmission lines from DPTS to a new zone substation at Truganina (**TNA**);
- construction of 66kV sub-transmission lines to transfer the existing MLN zone substation to DPTS, relieving constraints at KTS. As part of this work, the existing KTS to MLN and MLN to SBY 66kV sub-transmission lines will be reconfigured to bypass MLN and establish a KTS to SBY2 line. This maintains the required third supply to the SHM and SBY 66kV loop exiting KTS, which also supplies Gisborne (**GSB**) and Woodend (**WND**) zone substations; and
- construction of 66kV sub-transmission lines to transfer existing Sunshine zone substation (**SU**) to DPTS, relieving constraints at KTS. As part of this work, the existing KTS to SU2 and SU to Sunshine East (**SSE**) 66kV sub-transmission lines will be re-configured to supply SSE via its own loop from KTS.

A schematic of the inclusion of the DPTS into the electricity transmission and distribution systems is shown in figure 4.14.

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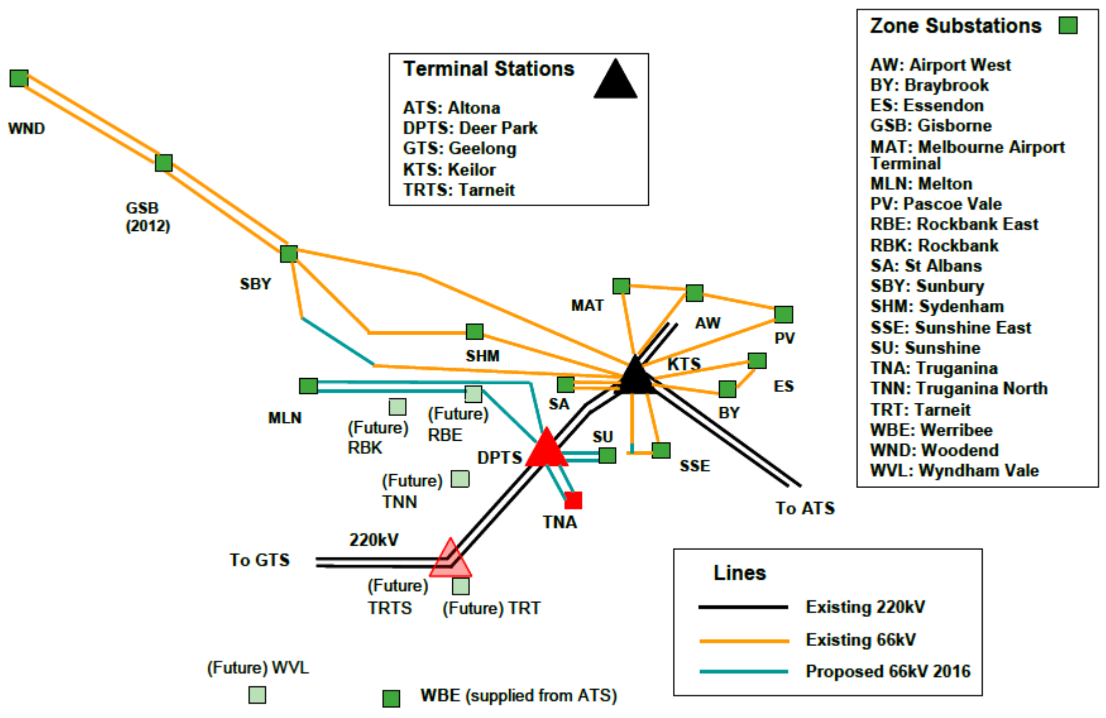
[45] For example, see AER, *TransGrid network exemption*, 30 January 2015, website accessed February 2015, http://www.aer.gov.au/node/30253.

[46] AEMO, *Jemena and Powercor, Joint Regulatory Test Report: Western Metropolitan Melbourne Transmission Connection and Subtransmission Capacity*; 1 May 2012.

Figure 4.14 Schematic of the Deer Park terminal station and associated works



Source: AEMO, *Jemena and Powercor, Joint Regulatory Test Report: Western Metropolitan Melbourne Transmission Connection and Subtransmission Capacity*; 1 May 2012, p. 48.

The works required by Powercor associated with the Deer Park terminal station have been approved by the Board.

Non demand driven expenditure – voltage compliance

Voltage levels are important for the operation of all electrical equipment, including home appliances with electric motors or compressors such as washing machines and refrigerators, or farming and other industrial equipment. These appliances are manufactured to operate within certain voltage threshold ranges.

Powercor is obligated to maintain customer voltages within specified thresholds, in accordance with the Victorian Electricity Distribution Code and the National Electricity Rules (**NER**).

Voltage levels are affected by a number of factors including:

- generation of electricity into the network;
- impedance of transmission and distribution network equipment;
- length of sub-transmission or distribution feeders;
- load; and
- capacitors in the network.

The long distance between the customer and the voltage regulating equipment e.g. transformers and regulators means that lower voltage levels are observed on the Powercor network and need to be carefully managed. Powercor is actively monitoring lines susceptible to voltage issues.

In addition, groups of solar photovoltaic generators are increasingly causing fluctuations in voltage levels in localised areas. Powercor is monitoring the voltages in these areas. Higher voltage levels caused by residential solar generation are a particular concern.

Approximately seven per cent of Powercor's augmentation capex is to manage voltage compliance on the 22kV high voltage network, and this voltage compliance need will increase in the future.

4.5 Material augmentation projects

Demand-driven augmentation projects, where the cost of the most expensive credible option is greater than $5 million, are required to satisfy the RIT-D. This test was introduced on 1 January 2014.

Where Powercor commenced assessing a project prior to the RIT-D commencement date, then those projects were assessed under the Regulatory Test.

For those augmentation projects where demand is not the primary driver of the project, then a RIT-D or Regulatory Test is not required. Powercor has provided an explanation of the options and preferred solution for these material projects.

4.5.1 Forecast capital expenditure that has satisfied the regulatory test

This section identifies the forecast augmentation capital expenditure for the 2016-2020 regulatory period that have satisfied the regulatory test, RIT-D or the regulatory investment test for transmission (**RIT-T**).

Table 4.5 Network service projects that have satisfied the regulatory tests

Project name	Test type	Cost ($ million, 2015)	Date of final report
Deer Park terminal station	Regulatory Test	16.01	1 May 2012
New Truganina zone substation	Regulatory Test	12.78	17 March 2014
Merbein new transformer	Regulatory Test	5.49	11 April 2014
Geelong East upgraded transformers	Regulatory Test	8.54	12 June 2014
New Torquay zone substation	Regulatory Test	14.36	2 May 2014

Source: Powercor
Note: direct costs excluding real escalation

The Deer Park terminal station project was discussed above. The other projects are discussed in turn below.

Truganina zone substation

Although the 66kV lines for this this project are also contained within the Regulatory Test for DPTS, Powercor undertook a separate regulatory test for the new TNA zone substation which was completed in March 2014.

The construction of TNA is needed to address the forecast system constraints at the Laverton (**LV**), Werribee (**WBE**), Laverton North (**LVN**), Sunshine (**SU**) and St Albans (**SA**) zone substations.

The current zone substations supply domestic, commercial and industrial customers in the western suburbs of Melbourne. Residential and commercial growth is expected to continue in Caroline Springs, Taylors Lakes, Hillside, St Albans, Sunshine, Tarneit, Hoppers Crossing, Williams Landing, Point Cook, Werribee, Wyndham Vale, as well as industrial growth in Ravenhall, Derrimut, Laverton, Laverton North and Truganina.

The establishment of the new TNA zone substation is needed to avoid loss of supply for an outage at any of the existing transformers within the zone substations noted above. The new TNA zone substation will reinforce supply, remove load and energy at risk and improve reliability of supply.

The Regulatory Test concluded that the preferred option is the construction of TNA zone substation containing two 66/22kV transformers, as well as the construction of two 66kV sub-transmission lines and five 22kV feeders in 2017.[47]

Merbein new transformer

The installation of a new transformer at Merbein (**MBN**) is required to address a forecast system constraint in the Merbein and Mildura areas. The MBN and Mildura (**MDA**) zone substations are both forecast to have significant load and hours at risk. MBN and MDA supply the domestic and commercial areas of Merbein and Mildura extending into the surrounding rural areas, and includes large grapevine viticulture.

Powercor completed a Regulatory Test in April 2014 relating to the forecast network constraints in the Merbein and Mildura area. The test concluded that the preferred option to manage the risk at both zone substations is the construction of a new transformer at the MBN zone substation, and to permanently transfer some MDA load to MBN.[48]

Geelong East upgraded transformers

An upgrade of two of the transformers at the Geelong East (**GLE**) zone substation, as well as changing the configuration to be fully switched, is needed to address the risk of customers not being supplied during high load periods.

The GLE zone substation supplies the domestic, commercial and industrial areas of Geelong East, Leopold and extending into surrounding rural areas,

The GLE zone substation is comprised of three 10/13.5 MVA transformers operating at 66/22 kV. However, the station is currently operating above its N-1 capacity, and due to expected increases in demand at the station, prior to any load transfers that may be undertaken, is forecast to be above its N rating in 2015.

Powercor completed a Regulatory Test in June 2014 relating to GLE. This test concluded that the preferred option is to augment capacity by replacing two of the existing 10/13.5 MVA transformers with 25/33 MVA transformers in 2017. In addition, the report recommended the zone substation be fully switched so that a faulty transformer can be isolated and the remaining transformers could continue to operate and supply the station load.[49]

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47 Powercor, *Truganina (TNA) Zone substation regulatory test report*, 17 March 2014, pp. 5-6.

48 Powercor, *Merbein (MBN) and Mildura (MDA) regulatory test report*, 11 April 2014, pp. 5-6.

49 Powercor, *Geelong East (GLE) zone substation transformer upgrades regulatory test report*, 12 June 2014, p. 4.

Torquay zone substation

The construction of TQY is needed to address the forecast system constraints in terms of load as well as voltages on the 22kV feeders from the Waurn Ponds zone substation (**WPD**).

The WPD zone substation is served by two sub-transmission lines from the Geelong terminal station (**GTS**). It supplies the domestic and commercial customers in the Geelong suburbs of Waurn Ponds, Grovedale, Belmont and Highton as well customers in the Surf Coast towns of Torquay, Jan Juc, Anglesea and Lorne.

Currently, the WPD zone substation is comprised of one 10/13.5 MVA transformer and two 25/33 MVA transformers operating at 66/22 kV. Maximum demand currently exceeds the N-1 rating and is forecast to increase over the forward planning period and beyond as a result of new commercial customers, including a hospital, and a residential housing development in the Armstrong Creek area.

Furthermore, Powercor constructed new 22kV feeders from WPD to Torquay in 2006 and 2013, however there is limited scope to build any more feeders down the road corridors and to adequately redistribute the load. While Powercor will install voltage regulators and high voltage capacitors to manage voltage issues in the Torquay/Surf Coast areas over the next four years, by 2018 however such measures will be unable to ensure compliance with the minimum voltage standards in the Victorian Electricity Distribution Code. Powercor completed a Regulatory Test in May 2014 which identified the construction of TQY in 2018 and 2019 as the preferred option.[50]

4.5.2 Large projects

Not all large augmentation projects have completed the RIT-D process. This section discusses those projects that cost more than $5 million but where a RIT-D will not be undertaken as the project falls within the exceptions set out in clause 5.17.3 of the Rules, or where a RIT-D has not been completed yet.

Table 4.6 Network service material projects

Project name	Drivers	Cost ($ million, 2015)	Proposed RIT-D start date	Material project no.
Melton new transformer	Demand	4.9	Commenced	AUG 26
TNA third transformer	Demand	8.2	2016	AUG 27

Source: Powercor
Note: direct costs excluding real escalation

Each of these projects is described below.

Melton new transformer

A new transformer is needed at the Melton (**MLN**) zone substation and is required to address the risk of all customers not being supplied in the Melton and Bacchus Marsh areas during high load periods in the event of a loss of a transformer.

[50] Powercor, *Torquay (TQY) zone substation 2018-2019 regulatory test report*, 2 May 2014, p. 4.

The MLN zone substation supplies the domestic, commercial, industrial and farming areas of Melton, Melton South, Melton West, Kurunjang, Rockbank and Brookfield.

Both the MLN and Bacchus Marsh (**BMH**) zone substations are currently operating above their N-1 capacity. As there is limited load transfer capability between BMH and MLN zone substations, customers could potentially be left without electricity if a transformer fails until capacity in the neighbouring network becomes available for supply to be restored.

As forecast load growth continues, the available transfer capability diminishes, leaving a greater number of customers exposed to the risk of supply interruption due to insufficient network capacity.

Powercor commenced the RIT-D process for the MLN and BMH areas in August 2014 through the publication of a non-network options report.[51] Powercor did not receive any responses to the consultation. Powercor's preferred option is the installation of a new transformer at MLN in 2016 and 2017, in addition to increasing 22kV feeder ties between MLN and BMH to permanently transfer load from BMH to MLN. The RIT-D process is being conducted using the VCR rates provided by AEMO in September 2014.

Truganina third transformer

The new Truganina (**TNA**) zone substation is proposed to be constructed with two transformers in 2017. However, by the summer of 2019/20 there will be insufficient capacity to supply all customers in the event of a transformer failure at TNA, Werribee (**WBE**), Laverton (**LV**), Laverton North (**LVN**), St Albans (**SA**) or Sunshine (**SU**) zone substations.

To address the anticipated system constraints, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- option 1-install a third transformer at TNA zone substation in 2019;
- option 2-utilise generation at TNA, WBE, SU & SA to defer option 1 by five years; or
- option 3-use demand management at LV, WBE, SU, SA and LVN ZSS to defer option 1.

At this stage, Powercor has not received any costs from possible generation or demand management proponents to address or defer the load at risk at TNA. Powercor's own estimates indicate that the cost of any non-network solution would far exceed the network solution proposed in option 1.

Powercor's preferred option is to install a third transformer at TNA with a commissioning date of November 2019. A RIT-D for this project is expected to commence in 2016.

4.6 Augex model

In assessing augmentation expenditure forecasts, the AER indicates in its *Expenditure Forecast Assessment Guidelines* that it will use several tools to review each distributor's forecasts:[52]

- assess a distributors' forecasting approach, by assessing the processes, documentation and models used to derive components of the forecast;

[51] Powercor, *Non-network Options report Melton (MLN) and Bacchus Marsh (BMH)*, 6 August 2014.

[52] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, pp. 167-168.

- perform detailed reviews of a sample of projects, with assistance from technical and other consultations, paying particular attention to the extent that non-network solutions were considered;
- infer the finding of those reviews to the rest of the augmentation expenditure population;
- undertake individual project cost analysis, by using average cost benchmarking from a database of costs and volumes from major augmentation projects; and
- apply the 'augex' model, which uses information on capacity, utilisation and demand patterns in network segments, and unit costs to produce an alternative forecast.

The augex model is a new tool that Nuttall Consulting has developed for the AER, and it has not yet been applied in regulatory determinations. The AER has previously attempted to assess augmentation using modelling, where Nuttall Consulting determined an average weighted probability of forecast augmentation and applied that to the distributor's forecast in the 2010 draft determination.[53] However, the AER decided not to rely upon that tool in the final determination, noting that:[54]

> *…the AER agrees in principle that the weighted average probability assessment recommended by Nuttall Consulting is a credible and valid methodology. However, the AER acknowledges that this methodology requires further testing in order to be used to reliably determine what the total forecast reinforcement capital expenditure that would reasonably reflect the capital expenditure criteria over the forthcoming regulatory control period. For these reasons, the AER has decided not to apply this methodology to determine the total reinforcement capex in this final decision.*

The AER's concerns about the ability of the forecasting tool to provide forecasts that achieve the capital expenditure criteria remain valid and must be demonstrated if it is to rely upon the augex model. This is because:

- Nuttall Consulting noted that augex model is a 'Regulatory tool **NOT** planning/management tool';[55]
- the AER indicates that it may use the model in a deterministic manner, noting in the *Expenditure Forecast Assessment Guidelines* that:[56]

  > *We do not intend to use the augex model as the sole reference point to deterministically set the augex component of a DNSP's capex forecast. …However, this does not preclude us from substituting some or all of the forecasts from the augex model for some or all of the augex components of a NSP's capex forecast.*

- the capital expenditure criteria in clause 6.5.7 of the Rules requires the AER to accept the forecast of required capital expenditure if it reasonably reflects a realistic expectation of the

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53 AER, *Victorian electricity distribution network service providers distribution determination 2011-2015*, draft decision, June 2010, p. 316.

54 AER, *Victorian electricity distribution network service providers distribution determination 2011-2015,* final decision, October 2010, Appendix P, p. 522.

55 AER, AER expenditure workshop no.4 slides – DNSP replacement and augmentation capex – 8 March 2013, available from https://www.aer.gov.au/node/19508.

56 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Explanatory Statement, November 2013, p. 169.

demand forecast and cost inputs required to achieve the capital expenditure objectives. This includes the requirement to meet or manage the expected demand, and well as the quality, reliability or security of supply for standard control services.

Powercor is therefore concerned about the juxtaposition of the uses of the augex model to forecast the capital expenditure necessary to meet expected demand but not being appropriate to be used as a planning tool.

4.6.1 Overview of the augex model

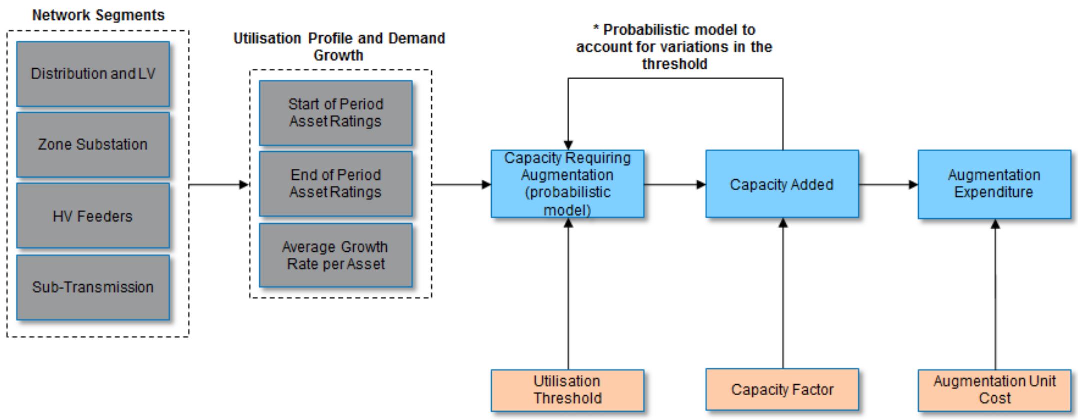
The AER's aim of the augex model is to 'simplify the analysis of complex forecasting methods while still maintaining some ability at the aggregate level to allow for the main drivers of augmentation'.[57]

The augex model only models demand-driven network capital expenditure. The model determines whether an asset needs augmentation based on the utilisation of the asset. When the peak demand of the asset reaches a certain proportion of its capacity, then it triggers augmentation.

The thermal rating of an asset is used as the basis for its capacity. The asset utilisation at a point in time reflects the proportion of a limit being used at that time i.e. the demand/ thermal rating.

An overview of the model is provided in figure 4.15.

Figure 4.15 Overview of the AER's augex model



Source: Powercor

The model uses three planning parameters to prepare forecasts, in particular:

- utilisation threshold-defines the point, on average, when assets need to be augmented i.e. they will breach reliability standards or exceed the economic point of maximum utilisation;
- capacity factor-the amount of capacity that needs to be added to an asset for each unit that is found to require augmentation; and
- augmentation unit cost-represents the average cost for providing an additional unit of capacity to the network.

The model uses four assets classes, namely, zone substations, sub-transmission lines, high-voltage (**HV**) feeders, and low voltage (**LV**) feeders together with distribution substations. Assets can be further divided into sub-categories, such as grounding by the primary type of areas served, or by the

57 AER, *AER augmentation model handbook*, Guidance document, November 2013, p. 14.

length of the lines. Different planning parameters are applied to each of these asset categories and subcategories.

Using the above information, the model simulates year-by-year forecasts of network augmentation over a 20 year period. The simulation uses an augmentation algorithm that contains the following three elements:

- capacity requiring augmentation-assuming a normal distribution for the utilisation threshold, defines the proportion of assets that will need to augmentation as the utilisation increases in the future, taking into account the demand growth rate;
- capacity added-the model multiplies the capacity requiring augmentation by the capacity factor parameter, however the model also considers whether this augmented capacity will also require augmentation later in the simulation period by feeding it back through the step above; and
- expenditure forecast-calculated as the total capacity added in the year by the augmentation unit costs.

4.6.2 Limitations of the augex model

The augex model attempts to simplify the analysis of a range of complex forecasting methods to predict augmentation expenditure for a given distributor. Essentially, the model assumes a distribution network with rigid, deterministic planning criteria, and predicable augmentation methods. In reality, there are ranges of different ways in which distributors plan and operate their networks. The simplifications in the augex model necessarily lead to a reduction in accuracy of the planning outcomes that would be expected from a distributor.

In summary, the augex model includes the following limitations:

- the model is very sensitive to small changes in parameters;
- sub-categories of assets may have small sample sizes, which can impact the accuracy of parameters;
- larger projects for some asset classes can have significant variability in scope, project costs and amount of capacity added to the network, resulting in historical data that is not appropriate for forecasting purposes; and
- history may not be a good predictor for the future.

These matters are discussed in turn below.

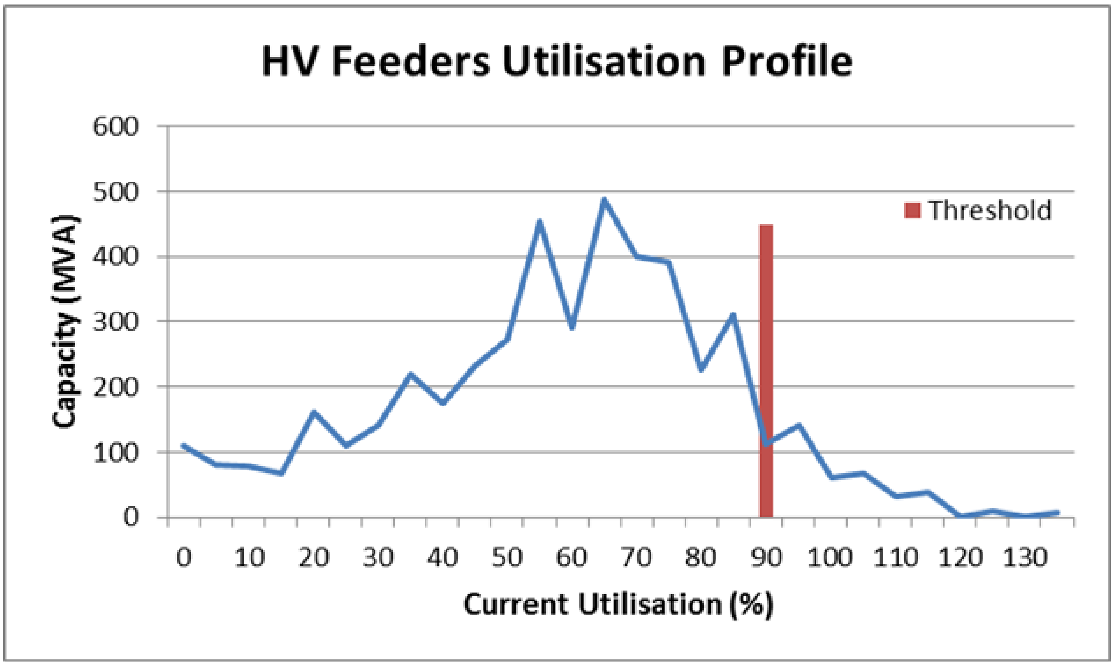
The model is very sensitive to small changes in parameters

The model is quite sensitive to small changes in the utilisation threshold and utilisation standard deviation.

For a given asset, there will typically be large amount of capacity not too far below the augmentation point. In this case, a threshold a little too low will augment far too much capacity, while if it is set a little too high the forecasts get delayed rapidly.

Take for example the utilisation profile for Powercor's HV feeders, shown in figure 4.16.

Figure 4.16 Utilisation profile for HV feeders



Source: Jacobs, *Powercor AER Augex modelling assistance*, 25 November 2014, p. 10.

The figure above shows that the threshold for utilisation is approximately 90 per cent, based on historical data. The bulk of assets are a little below the threshold, with some capacity near the augmentation point, and a few assets overloaded. The assets with high utilisations will have individual reasons why they haven't been augmented yet – with augmentation likely to occur in the next few years.

The augex model is also sensitive to the utilisation threshold standard deviation. Figure 4.16 shows that some of the highest utilised assets are about as far above the threshold as the bulk of the assets are below it. The 'standard deviation' parameter controls for this effect, as capacity is not augmented all at once when it hits the threshold, but gets spread out over a few years. However, the augex model assumes a normal distribution, with augmentation equally as likely above and below the threshold point.

Therefore, if the augex model uses a low standard deviation, it will immediately augment everything that is highly utilised, while if the deviation is set too high, the augex model will consider assets substantially below the threshold as potentially in need of augmentation.

Getting sensible input parameters is challenging with a small number of samples

The model is also sensitive to forecast planning parameters, particularly the Capacity Factor. The Capacity Factor represents the response of the distributor to highly loaded assets, and is typically based on historic data. However, especially in the case of sub-transmission and zone substation asset classes, there are typically only a few historic projects to derive this forecast planning parameter from.

The small sample sizes mean that the results may not be statistically representative of the actual results. This will lead to inaccuracies in the modelled outputs.

Variability in scope of historical projects

Larger projects of these asset classes can have significant variability in project scope, costs, and amount of capacity added to the network.

For example, there are many potential drivers for augmentation of the sub-transmission network, including constraints at a zone substation or on feeders. Solutions to overcome the capacity constraints are therefore unique to the location of the constraint and the network configuration. The number of constraints and associated augmentation projects at this level of the network is generally small, and as such there is no 'average' sub-transmission project.

This has been observed by Jacobs in reviewing the augex model inputs for Powercor. In its report, Jacobs observed that the type of planned network augmentations over the 2016-2020 period involves significant construction of new substation and sub-transmission lines assets, while the past projects from which several figures were derived involved a different makeup (e.g. smaller additions or uprates).[58]

Jacobs noted that forecast planning parameters derived from the smaller numbers of samples, or from periods where program of works were different from current planning, tend to produce inconsistent forecasts.[59] That is, the augex model outputs would be significantly at variance with the actual expenditure requirements.

History may not be a good predictor of the future

The drivers of network augmentation are often outside of the control of the distributor. The augex model appears to assume that the past is a good predictor of the future, which implicitly assumes that the distributor has implemented an optimal augmentation strategy.

The augex model fails to account for changes in circumstances. For example, a network may have invested in overhead networks in the past but may need to invest in the more costly underground networks going forward. As a result, the augex model may underforecast required expenditure.

4.6.3 Populating the augex model

Jacobs assisted Powercor in populating the augex model. It has prepared a report which outlines the steps that were undertaken in the model population, as well as addressing the matters set out in paragraphs 7.2(a) and 7.2(d) of the RIN.[60]

At a high level, Jacobs has undertaken the following four steps in populating the input data for the augex model:

- configured the asset class groupings into categories and sub-categories, and avoiding detailed sub-categorisation or subgrouping as advised by the AER's augmentation model handbook;
- determined a 'base case' by establishing the value of the Utilisation Threshold Mean by observing the graphical pattern of the asset utilisation, and the capacity factor was derived from the available completed project data. Other input parameters were determined by either referring to the populated Reset RIN Tables corresponding to the respective asset class, or by

58 Jacobs, *Powercor AER Augex modelling assistance*, 25 November 2014, p. 10.

59 Jacobs, *Powercor AER Augex modelling assistance*, 25 November 2014, p. 11.

60 Jacobs, *Powercor AER Augex modelling assistance*, 25 November 2014.

referring the historical or/and planned demand driven project information, project cost, and estimation data;

- modelled the capacity added after identifying input parameters that produced plausible capacity forecast; and
- modelled the cost forecast by using average unit costs from project cost data in a particular asset class.

Addressing the change in forecast work in the augex model

For sub-transmission lines, Jacobs observed that historical demand driven projects were all projects for the uprating of lines. That is, where the clearance between the sub-transmission line and ground or subsidiary lines is increased to re-rate the maximum operating temperature, thus increasing the capacity of the line.

In contrast, Powercor's demand driven planned and committed construction in the 2016-2020 period involves significant network restructuring, and the construction of two new zone substations and associated sub-transmission lines infrastructure.

As the nature of forecast augmentation work is different from past projects, Jacobs adjusted the following parameters in the augex model:

- increasing the capacity factor, to reflect the large amount of new capacity planned rather than increasing the capacity of a single line;
- lowering the utilisation threshold mean value, as network reconfiguration targets a broader range of network constraints than a single line uprating project

The changes in these input parameters ensure that the augex model is able to address the changing nature of sub-transmission line projects for Powercor.

Source: Jacobs, *Powercor AER Augex modelling assistance*, 25 November 2014, p.15

The input parameters that Jacobs have used in its augex modelling are shown in table 4.7.

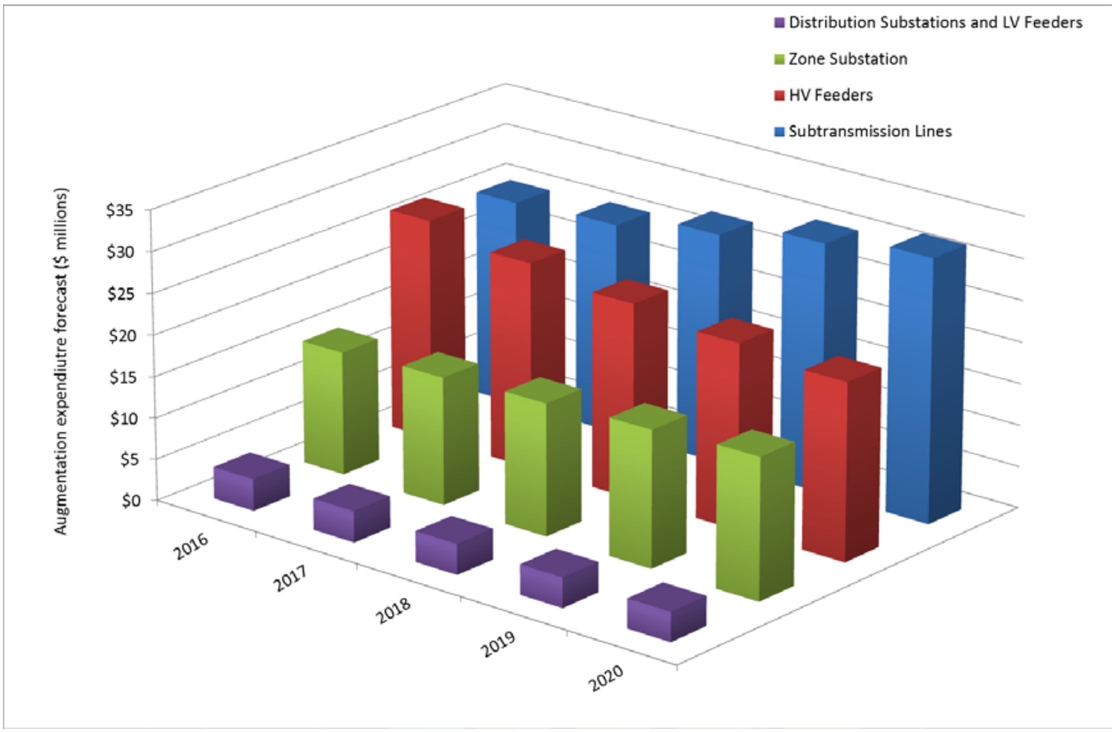
Table 4.7 Input values for AER augex model

Network segment title		AER segment group	Forecast planning parameters				
Asset class	Asset categories/ subcategories		000' $/MVA	Cap Factor	UT Mean	UT σ	Max Demand
Sub-transmission lines	<0% growth pa	1	$71.77	1.71	113.4%	16.7%	0.00%
	0%-2% growth pa	1	$71.77	1.71	113.4%	16.7%	0.96%
	2%-4.5% growth pa	1	$71.77	1.71	113.4%	16.7%	3.61%
	>4.5% growth pa	1	$71.77	1.71	113.4%	16.7%	5.14%
HV feeders	Urban	5	$108.13	0.64	74.7%	12.1%	1.52%
	Rural Short	6	$142.00	2.32	86.1%	12.1%	1.77%
	Rural Long	7	$103.37	0.71	107.0%	12.1%	1.03%
Zone substation	Urban	3	$231.86	0.47	82.9%	30.5%	3.37%
	Rural	3	$231.86	0.47	79.3%	30.5%	2.83%
Distribution transformers and LV feeders	NA	9,10,11	$109.00	1.00	137.0%	20.0%	1.47%

Source: Jacobs, *Powercor AER Augex modelling assistance*, 25 November 2014, p. 21.

Given the input parameters, the output of the augex model in terms of annual augmentation expenditure is shown in figure 4.17.

Figure 4.17 Powercor's augex model forecast output summary – annual expenditure



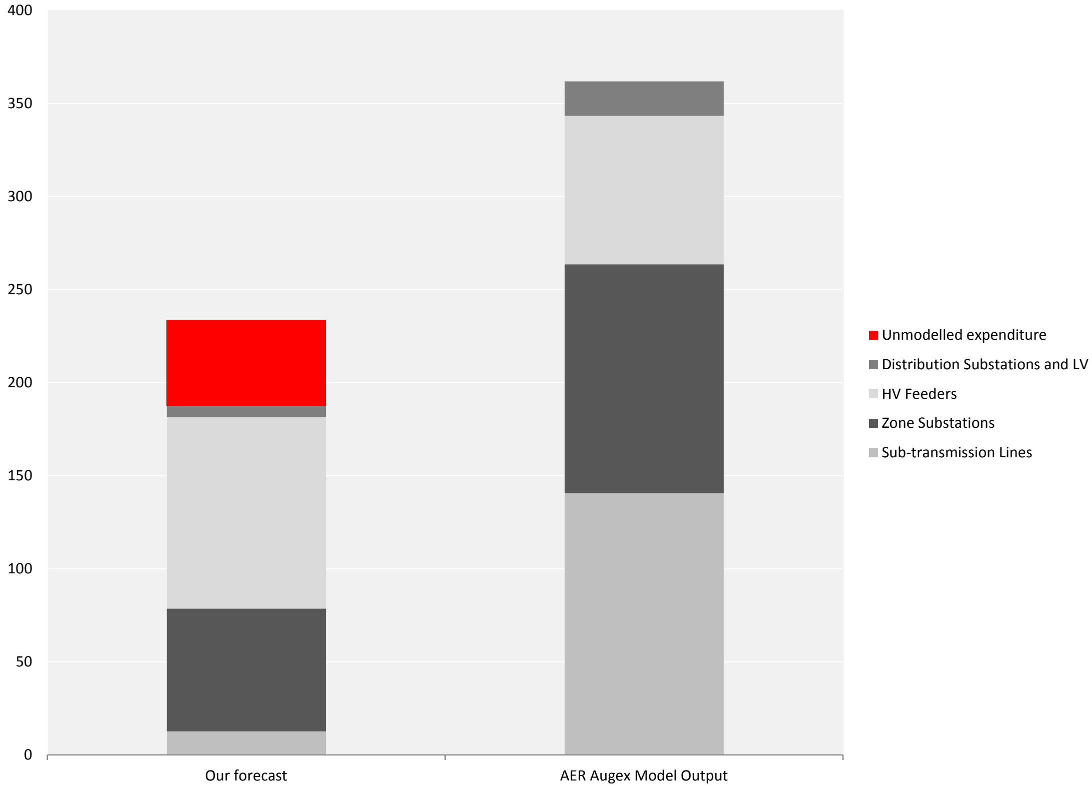
Source: Jacobs, *Powercor AER Augex modelling assistance*, 25 November 2014, p. 6.

4.6.4 Reconciliation

Powercor has not used the AER's augex model as the primary basis for forecasting augmentation expenditure, rather it has used the methodology outlined in section 4.2.3 to establish its forecast for augmentation expenditure.

The augex model forecasts a higher level of expenditure required for augmentation related works compared to Powercor's forecasts, as shown in figure 4.18.

Figure 4.18 Comparison of Powercor's forecast to augex model forecast output ($million, 2015)



Source: Powercor
Note: direct costs excluding real escalation

Powercor estimates that 80 per cent of its augmentation expenditure is covered by the drivers in the AER's augex model.

The AER's augmentation model handbook identifies instances that the augex model does not cover, including:[61]

- fault level mitigation works, which by their nature are not directly related to the peak loading of assets;
- augmentation to manage low demand situations; and
- augmentations driven largely by the connection of generation and the ability of the network to export the supply from the generation.

In addition to the above, Powercor notes that the augex model does not cover:

- augmentation of distribution assets driven by transmission connection asset constraints;
- augmentation to deliver security of supply;
- augmentations to address supply quality (i.e. voltage compliance that is unrelated to peak demand); and

61 AER, *AER augmentation model handbook*, Guidance document, November 2013, p. 33.

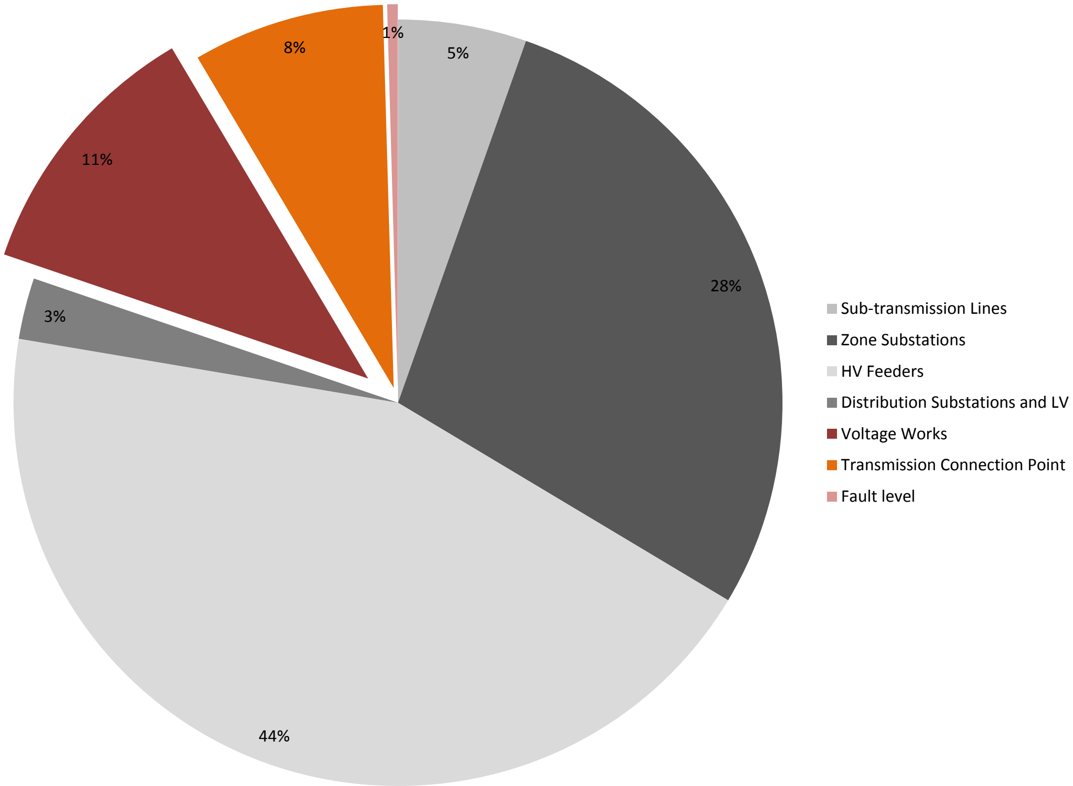
- ancillary costs associated with large augmentation projects, such as secondary control and protection equipment.

For Powercor, the remaining 20 per cent of its augmentation expenditure that is not covered by the augex model relates to:

- addressing the transmission network constraint at Keilor terminal station;
- voltage compliance issues; and
- fault level works.

This is shown in figure 4.19.

Figure 4.19 Augmentation expenditure not captured by augex model



Source: Powercor

The items of unmodelled augmentation expenditure are discussed in turn below. The outcome of these projects will not result in an increase in the capability of the Powercor network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level.

Transmission network constraint

As discussed previously in this chapter, Powercor is rearranging its network to address a constraint at the Powercor and Jemena networks transmission connection point at Keilor terminal station (**KTS**). This involves the construction of a new terminal station at Deer Park (**DPTS**), and sub-transmission line rearrangement works so that the Melton (**MLN**) and Sunshine (**SU**) zone substations are served by DPTS rather than KTS.

The augex model captures the works associated with the new Truganina (**TNA**) zone substation, as this is a demand-driven project that addresses constraints on the distribution network.

Voltage compliance issues

The augex model also does not capture costs associated with voltage compliance management on Powercor's 22kV high voltage network. The long distance between the customer and the voltage regulating equipment e.g. transformers and regulators on the network means that lower voltage levels can result, and must be addressed if they are forecast to breach the specified thresholds.

Fault level mitigation works

Powercor has forecast a small amount of expenditure to address safety and fault level issues on its network. Fault level mitigation programs are becoming increasingly common on the Powercor network as the level of embedded generation being directly connected to the network increases. This is because of the increasing fault level contribution from generators which the network was not designed for when originally conceived.

4.7 Synergies between augmentation and replacement

Powercor is able to use both the load indices and health indices at zone substations to obtain an overall picture of the current load and condition of the zone substation transformers, and how this is expected to change overtime.

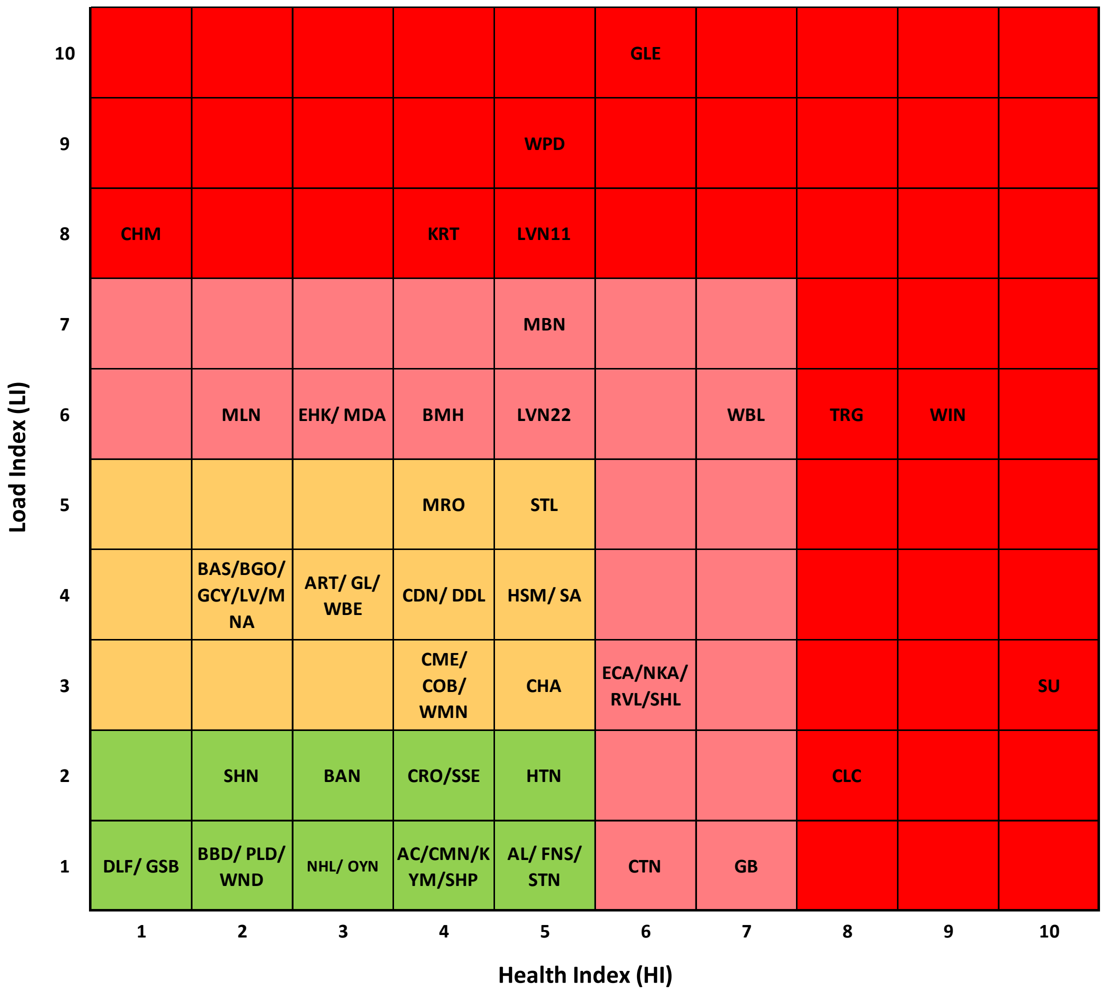
A matrix can show which zone substations have transformers that:

- have large amounts of energy at risk in peak times, and may require augmentation, with a high load index;
- are in poor health and in need of replacement, with a high HI; and
- have large amounts of energy at risk at peak times and are in poor health, with high load and health indices, where the transformers are in need of replacement with a higher capacity transformers.

The overall picture can highlight project synergies. For example, if a particular zone substation has a high load index and transformers with a poor HI, an augmentation project to replace the transformers with higher capacity units will reduce both the load related and health related index measures.

The matrix in figure 4.20 shows the load and health indices for each zone substation that is expected at the start of the 2016–2020 regulatory control period. This takes into account expected works during the 2015 calendar year.

Figure 4.20 Load and health indices at zone substations at start of 2016



Source: Powercor

As can be seen, Powercor has high load index at Geelong East (**GLE**), Waurn Ponds (**WPD**), Koroit (**KRT**) and Laverton North (**LVN11**) zone substations. Charum (**CHM**) is a single transformer zone substation and as such is given a load index of eight. Powercor also has high health indices at the Geelong B (**GB**) and Colac (**CLC**) zone substations, as well as the Sunshine (**SU**) zone substation which is currently being redeveloped. The Winchelsea (**WIN**), Terang (**TRG**), and Warrnambool (**WBL**) zone substations are in poor condition, and have medium to high load at risk at peak times.

If Powercor does not invest in augmentation and replacement works over the 2016–2020 regulatory control period, i.e. 'do nothing', then an increasing number of zone substations will have load and health indices as shown in the matrix (figure 4.21) below.

Figure 4.21 Load and health indices at zone substations at the end of 2020 in the 'do nothing' scenario

Load Index (LI)										
10		LV			MBN	WPD	GLE			
9		MLN	WBE		SA	LVN22		WBL		WIN
8	CHM			BMH		LVN11				
7			MDA			STL				
6				EHK					TRG	
5		GCY		CDN/ MRO	DDL	HSM				
4		BAS/ BGO/ MNA	ART	GL		SHL				SU
3				BAN/COB/ CRO/KRT	HTN/ SSE/ WMN		ECA/ NKA/ RVL		CLC	
2		SHN	NHL/ PLD			CHA				
1	DLF/ GSB	BBD/ WND		AC/ OYN	CME/CMN /KYM/SHP	AL/ FNS/ STN		CTN/ GB		
	1	2	3	4	5	6	7	8	9	10

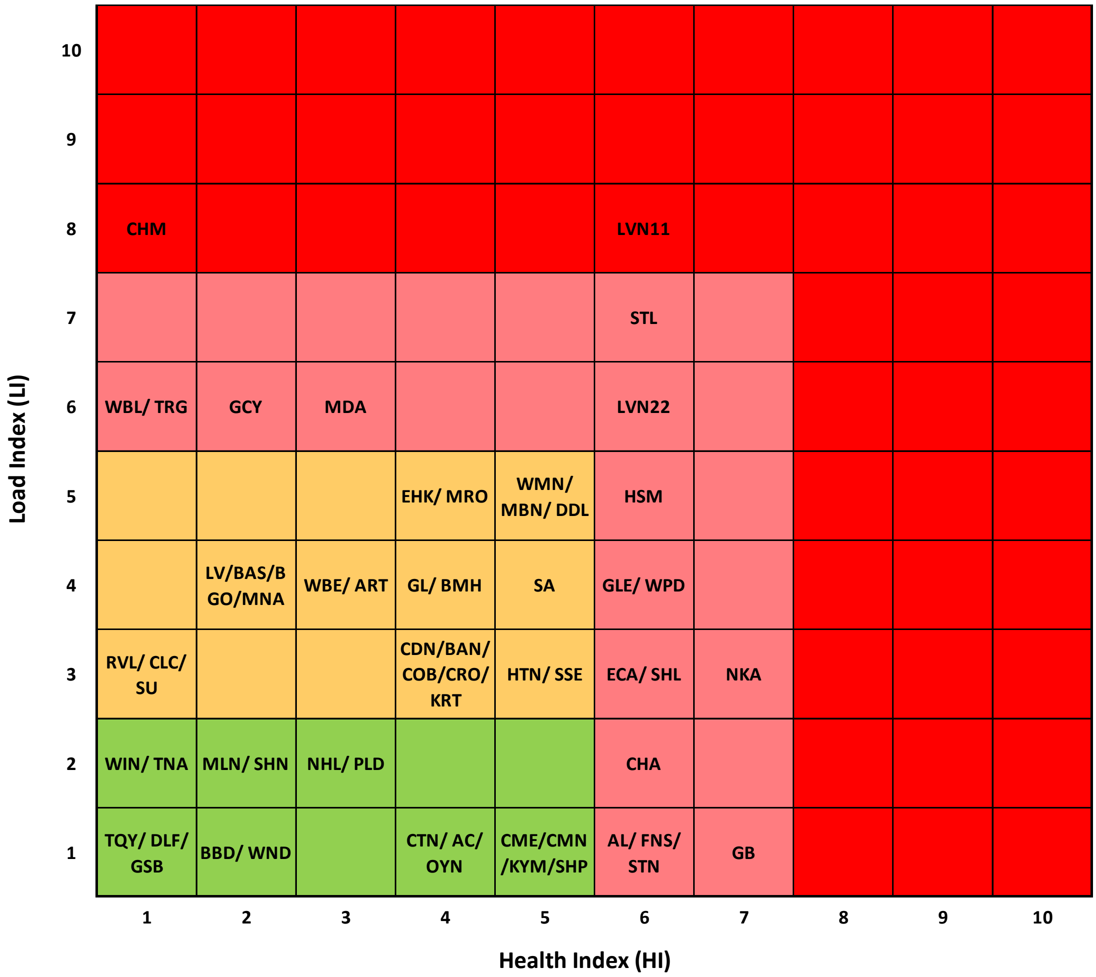
Health Index (HI)

Source: Powercor

If Powercor does not invest, then 12 zone substations will have high load indices including several zone substations in the western suburbs of Melbourne, and two in the Geelong region. Eight zone substations will have high health indices, and three zone substations will have high both load and health indices. It is clear that if Powercor does not invest, then its customers would experience a vast increase in the number of outages as the assets become overloaded and/or fail due to poor condition.

The matrix below shows the load and health indices for the zone substations given the expenditure contained within this regulatory proposal.

Figure 4.22 Load and health indices at zone substations at the end of 2020 with proposed expenditure



Source: Powercor

This matrix demonstrates that Powercor's proposed expenditure will address zone substations with high load and/or health indices. For example, the construction of the Truganina (**TNA**) zone substation will address the forecast load-related concerns at the zone substations in the western suburbs of Melbourne, and the construction of Torquay (**TQY**) zone substation will alleviate the load at risk at WPD.

In addition, the completion of the Sunshine zone substation redevelopment will address the poor condition of those assets, and the replacement of transformers at WIN, WBL and TRG will address both high load index and high HI issues at these zone substations.

5 Connections and customer driven works

When customers seek to connect to the network, or change their existing connection, then Powercor needs to meet its customers' requirements.

Powercor's forecast expenditure will enable it to connect customers to its network, including to supply new residential customers, assist industrial customers in expanding their operations, and to support connection of renewable energy generators.

A significant portion of this expenditure will be directly recovered from the connecting customer via a customer contribution.

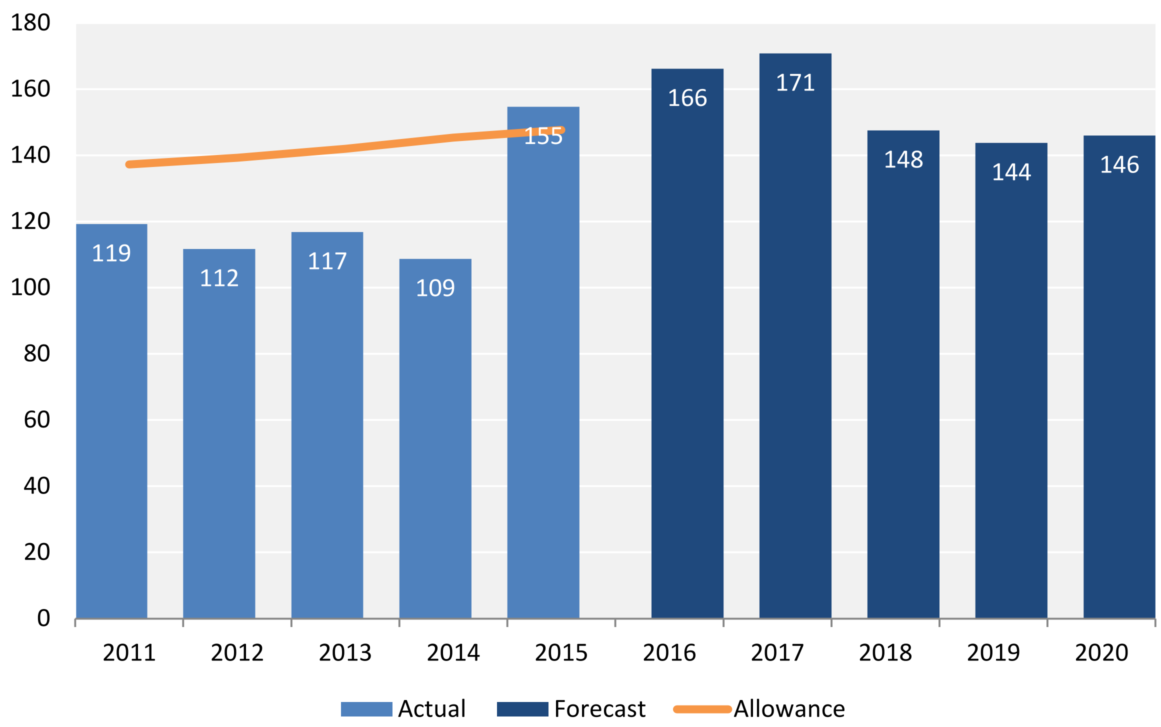
This section discusses Powercor's historical and forecast connection and customer driven works expenditure as well as the approach used in calculating the forecast expenditure.

5.1 Overview

Connections and customer driven works relates to expenditure to connect residential, commercial and industrial customers to the distribution network, connections for embedded generators and customer requested relocations (i.e. recoverable works).

An overview of historical and forecast gross capital expenditure is shown in figure 5.1. However, Powercor will receive funding directly from some customers towards their connection.

Figure 5.1 Gross connections direct capital expenditure ($ million, 2015) [62]



Source: Powercor

[62] 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

The profile shows that expenditure fell during the earlier part of the 2011–2015 regulatory control period. Similar to augmentation expenditure, Powercor experienced lower than expected customer connections as a result of the economic slowdown associated with the Global Financial Crisis. This was particularly noticeable in residential connections and subdivisions.

In the forecast period, the underlying residential and subdivision expenditure is not expected to significantly change compared to the levels in the 2011–2015 regulatory control period, although a small increase in commercial and industrial expenditure is forecast. However, the driver of the increase in expenditure is related to large and specific projects driven by government initiatives, expansion of the dairy industry and new windfarm connections.

Through the public forums undertaken as part of the stakeholder engagement program, some larger Powercor customers indicated that they are not happy with the connections process as it is too slow. Those customers accepted the need for network studies to be undertaken to assess the impact of their load on the network, particularly when their connection involved embedded generation, but considered that the overall process should be more streamlined. These views were reiterated in interviews with large customers, who generally had four core expectations of Powercor:[63]

- transparency in process–ensuring the process is well considered, transparent and in the best interests of the customer (with regular updates provided);
- work to exact timeframes–ensuring realistic and efficient timeframes, with commitment and guarantees that timelines will be met;
- flexibility and empathy–ensuring large customers are treated individually, with recognition that their large financial outlay and investment in electricity is valued and carried with it higher levels of flexibility, attention and responsiveness; and
- reliability and dependability–ensuring that Powercor is there for large customers when needed.

In contrast, focus groups with small and medium enterprise customers indicated few issues with the connections process, and were highly satisfied with the management and communication of new connections. However, some remotely based customers felt the associated costs of connection were excessive.[64]

Customer connections will continue to be an important area for Powercor into the future, and it is also expected that there will be an increase in embedded generators connecting to the network where customers are seeking to generate some of their power needs and to sell their excess electricity to the market.

5.2 Background

This section describes Powercor's methodology for forecasting connections and customer-driven works capital expenditure.

5.2.1 Key drivers for expenditure

The connections and customer-driven works category involves expenditure that is driven by customers, rather than being initiated by Powercor. The expenditure is influenced by economic

[63] Colmar Brunton Research, *Powercor stakeholder engagement research top 200 customers in-depth interviews*, 22 July 2014, p. 30.

[64] Colmar Brunton Research, *Powercor Stakeholder Engagement Research Report – Residential Customer Focus Groups and SME Customer Interviews*, 1 May 2014, p. 38.

conditions and development demographics, including major projects arising from government initiatives, commercial developments, embedded generation, changes in industrial and agricultural sectors and housing developments.

Connections and customer-initiated works expenditure is distinguished from augmentation capital expenditure based on the driver of the expenditure. For example, if the load associated with a new customer connection is expected to cause a capacity constraint on a sub-transmission line, the costs to augment the line will be allocated to the connections and customer-driven works expenditure category.

As an exception, where a customer connects embedded generation to the network, and the connection requires augmentation of the network beyond the first point of transformation, referred to as 'deep' augmentation, then the deep augmentation costs are captured in the augmentation category.

Aside from augmentation, Powercor does not consider that there is any reasonable scope for ambiguity between connections and customer-initiated works and any other category expenditure category.

5.2.2 Customer connection process

Powercor has different connection processes for customer connections depending on whether:

- the supply of electricity is already available to the property; or
- the applicant is seeking to connect for the purposes of receiving electricity and/or exporting electricity on to the grid.

The customer connection process is set out in *Powercor's customer guideline for making an electricity supply available*.[65]

The majority of residential connections are routine connections where Powercor can remotely connect the customer at the request of a retailer.

Where an overhead line, underground cable, substation, or embedded generator needs to be extended or upgraded to service new or upgraded customers, then the customer must submit an application to Powercor, which sets out the location of the premises and an estimate of the amount of electricity required. In response, Powercor will provide a budget estimate or firm offer to the customer, where the customer may also have the option to select other recognised contractors to complete works for contestable services.

The customer may be liable to pay a customer contribution towards the connection, where the contribution is calculated in accordance with *Electricity Industry Guideline No. Electricity Industry Guidelines 14 – Provision of Services by Electricity Distributors (*Guideline 14**).

[65] Available from: https://www.powercor.com.au/media/2185/powercor-customer-guideline-for-making-an-electricity-supply-available.pdf.

Calculation of customer contributions

Under the *Electricity Industry Guideline No. 14,* customer contributions are calculated according to the following calculation:

CC=[IC – IR] + SF

Where:

CC is the maximum amount of the customer's capital contribution;

IC is the amount of incremental cost in relation to the connection offer;

IR is the amount of incremental revenue in relation to the connection offer; and

SF is the amount of any security fee.

Incremental Cost (IC) is the cost of the project works including new incremental capital, operating maintenance and the costs of any works that Powercor will incur in making the supply available to the nominated point of supply. The Incremental Cost excludes the Connection Service Fees and transmission costs.

If the applicant chooses to run their own tender and use a Recognised Contractor other than Powercor to complete any Contestable Services, the applicant is required to provide Powercor with evidence detailing the total cost of these tasks. Powercor will compare those costs against the average cost for equivalent work completed on its lines, when calculating any Incremental Cost.

Incremental Revenue (IR) is the revenue that Powercor will receive from the new connection via the distribution tariffs. Revenue is allowed at 15 years for a business connection and 30 years for a domestic connection, in accordance with the guidelines.

The value of the Customer Contribution also depends on the amount of electricity that the customer agrees to use. The amount of electricity consumption that the customer requires is used to calculate your Incremental Revenue.

Security Fee (SF) is like a bond. It is the amount held by Powercor and returned with interest, should the applicant achieve the agreed electrical revenue consumption targets.

Where the customer seeking to connect an embedded generator onto the grid, then Powercor has two different processes for connections:

- where the connection is in accordance with Australian Standard 4777, then the customer must seek pre-approval for the connection; and
- all other connections are in accordance with the Guideline 14 or *Electricity Industry Guideline 15-Connection of Embedded Generators* (**Guideline 15**), or Chapter 5.3A of the Rules if the customer elects to follow the process.

Powercor is supportive of small solar generation that can be interconnected with its network. However, the pre-approval process allows Powercor to identify concentrations of solar PV systems on the low voltage network which can lead to potentially non-compliant power quality issues such as overvoltage and voltage unbalance.

Customer contributions for embedded generation are calculated in accordance with Guideline 15. Under these guidelines, embedded generators do not make any contributions for 'deep' augmentation but may contribute to 'shallow' augmentation, i.e. extension assets between generating plant and point of connection to the distribution network, and relevant connection assets required by the distributor.[66]

National Energy Customer Framework (NECF)

The NECF consists of a new National Energy Retail Law which would be applied in Victoria together with a range of Rules made by the AEMC, and would replace significant parts of the current State energy laws. It involves the transfer of Victorian responsibilities to a new national regulatory regime governing the sale and supply of energy to retail customers, including new connections to distribution networks.

For Victorian distribution businesses, the largest implication of adopting NECF would be that:

- Guidelines 14 and 15 fall away; and
- Chapter 5A of the Rules will apply in Victoria.

Pursuant to Chapter 5A of the Rules, the AER has published a *Connection Charge Guideline* which provides a guide to distributors to develop their connection policies.[67]

Should Victoria adopt NECF, or Chapter 5A of the Rules, then Powercor will be required to develop its connection policy in accordance with the AER guidelines, and then seek approval of the policy from the AER. The connection policy must be consistent with the connection charge principles set out in Chapter 5A of the Rules and the AER guidelines.

Powercor's connection policy under Chapter 5A of the Rules would use a different approach from Guidelines 14 and 15 for the calculation of connection charges and customer contributions. The calculation of the connection charges and customer contributions of Chapter 5A is set out in the box below.

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[66] Essential Services Commission, *Electricity Industry Guideline No. 15 – Connection of Embedded Generation*, August 2004, clause 3.3.2(b)(1)(B).

[67] AER, *Connection charge guidelines for electricity retail customers —under chapter 5A of the National Electricity Rules*, June 2012.

Calculation of connection charges under chapter 5A connection charge guideline

The connection charge guideline specifies the connection charge cost to the customer is calculated as follows:

Connection Charge = AS + PS + SF + CC

Where:

- **AS** is the charge payable for relevant alternative control services;
- **PS** is contribution to any relevant pioneer scheme. If an dedicated extension ceases within seven years after its construction to be dedicated to a customer, then that customer is entitled to a refund, which may be recovered from new users of the asset;
- **SF** is a security fee which Powercor charges on high-risk new connections such as mines and drought-prone irrigation. Powercor refunds 1/5th of the security each year unless the revenue forecasts are not realised
- **CC** is the capital contribution payable for all relevant standard control services

The capital contribution payable by the customer included within the calculation is calculated in accordance with the following calculation:

Capital contribution= ICCS + ICSN – IR

where:

- **ICCS** is Incremental Cost Customer Specific
- **ICSN** is Incremental Cost Shared Network subject to an agreed augmentation threshold, but excluding micro-embedded generators
- **IR** is Incremental Revenue which is calculated as the present value of expected distribution revenue over 30 years (residential) or 15 years (non-residential)

5.2.3 Customer contributions

Powercor's forecasting methodology document outlined that it was unclear at this stage whether it will be required to comply with the AER's *Connection Charge Guideline* issued under Chapter 5A of the Rules[68] or the ESCV's Guidelines 14 and Guideline 15 when determining connection charges, including capital contributions.

Powercor therefore noted that for the purposes of developing the expenditure forecasts, it would assume the *AER's connection charge guideline* would apply. In addition, Powercor would assume the current requirement set out in clauses 2.2 and 2.3 of Guideline 14 for distributors to contribute avoided costs to underground, relocate or modify any of a distributor's distribution assets will be preserved over the 2016-2020 regulatory control period.[69]

[68] AER, *Connection charge guidelines for electricity retail customers —under chapter 5A of the National Electricity Rules*, June 2012.

[69] Powercor, *2016-2020 Price Reset –Expenditure Forecasting Methodology*, 30 May 2014, p. 8, 20.

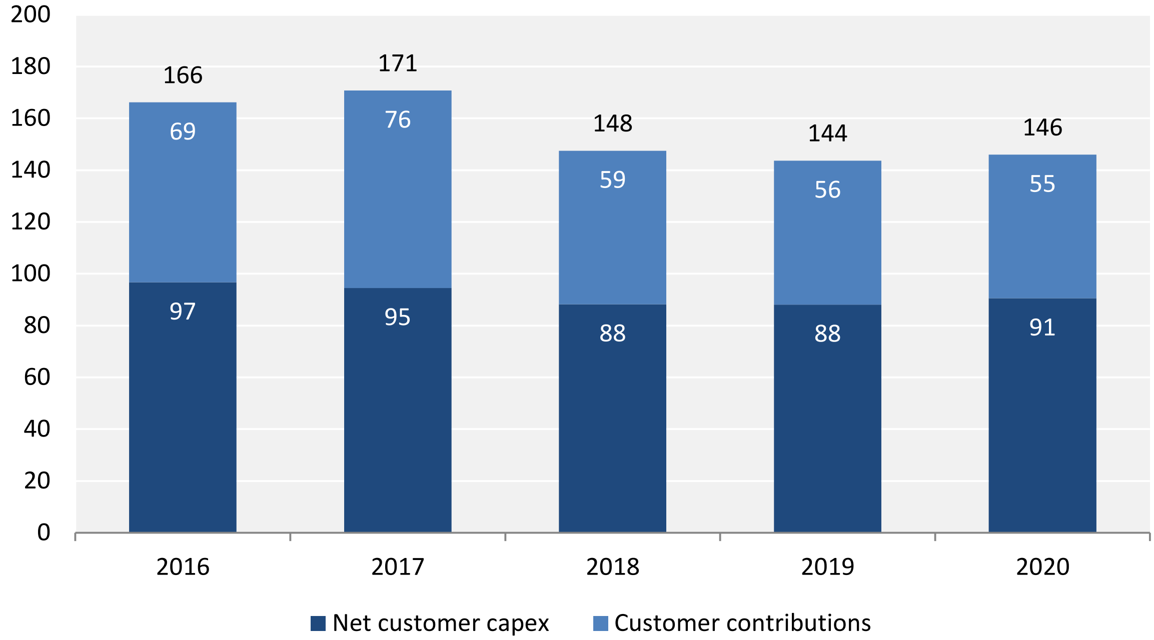
However, in the final Framework and Approach (**F&A**) paper, the AER indicated that it will continue to operate on the basis that Guidelines 14 and 15 will apply in Victoria.[70]

Consequently in calculating the customer contributions for the capital expenditure forecasts, Powercor has now assumed that Guidelines 14 and 15 will continue to apply. Therefore, in its expenditure forecasts, Powercor has provided two sets of forecasts to the AER, in particular:

- gross connection costs; and
- net connection costs, where the revenue obtained from customers is netted-off against the costs assuming that Guidelines 14 and 15 are in place.

An overview of the gross and net connection costs, as well as an estimate of customer contributions, is provided in figure 5.1.

Figure 5.1 Customer contributions



Source: Powercor

Customer contribution forecasts have been calculated by multiplying a calculated contribution rate by the gross connection capital expenditure in each of the internal reporting categories i.e. function code. The contribution rates were calculated by first selecting a representative sample of 2013 customer projects for each connection function code. The sample contains historical information on the average consumption expected by the customer, given the mix of customer types (e.g. apartment, shop, etc). The expected life of the customer is 15 or 30 years, depending on whether or not the customer is a residential customer.

The customer contribution rate for each sample project was re-calculated with changes made to the following inputs:

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[70] AER, *Final Framework and approach for the Victorian Electricity Distributors—Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 43.

- total project cost, augmentation rates, incremental operating and maintenance expenditure and tariff rates escalated to 2016;
- the Weighted Average Cost of Capital (**WACC**) and X factors applied in the calculation of the customer contribution were updated using Powercor's proposed WACC and X factors for the 2016–2020 regulatory control period;
- overhead rate adjusted to reflect that corporate overheads will no longer be applied to capital from 2016; and
- an additional incremental cost item included for incremental corporate income tax cost.

Attached is the *Contribution rate model*.

The AER noted that if it can be established in time for the determination that Guidelines 14 and 15 are to be removed and not replaced with new jurisdictional charging provisions, then its intention is to apply the AER's connection charge guideline to the Victorian distributors.[71]

Powercor has not estimated the change in customer contributions that would result from the introduction of NECF or Chapter 5A of the Rules and calculated in accordance with the AER *Connection Charge Guideline*.

5.2.4 Forecasting methodology

Powercor has used two different methodologies for forecasting customer connections into the AER's specified categories depending on whether the category of connection has a high or low volume of activity:

- for high volume categories of connections, forecasts of the number of customer connection jobs have been estimated by an external economic consultant using key economic and demographic variables (including growth in population, new dwellings, gross state product, new business, and new non-residential dwellings) to project historical data; and
- for low volume categories of connection categories, forecasts of customer connections have been estimated using a bottom-up build of major projects.

A mapping of the applicable AER's sub-categories for standard control connection services to the forecasting methodology is set out in table 5.1.

[71] AER, *Final Framework and approach for the Victorian Electricity Distributors—Regulatory control period commencing 1 January 2016* , 24 October 2014, p. 43.

Table 5.1 Methodologies for forecasting connections expenditure

Sub-category	Classification	Methodology
Residential	Simple connection LV	Economic forecast
	Complex connection LV	
	Complex connection HV	
Commercial/ Industrial	Simple connection LV	Economic forecast
	Complex connection HV – connected at LV, minor HV works	
	Complex connection HV – connected at LV, upstream asset works	
	Complex connection HV (customer connected at HV)	Bottom-up build
	Complex connection sub-transmission	Economic forecast
Subdivision	Complex connection LV	Economic forecast
	Complex connection HV (no upstream asset works)	
	Complex connection HV (with upstream asset works)	
Embedded generation	Complex connection LV	None for Powercor
	Complex connection HV (small capacity) (000's)	Bottom-up build
	Complex connection HV (large capacity)	

Source: Powercor

These methodologies are discussed in more detail below.

High volume categories of connections

From table 5.1, economic forecasts have been prepared for the following categories of connections which are associated with high volumes of activity:

- residential complex connection at LV;
- residential complex HV works connected at LV;
- commercial/industrial HV works connected at LV; and
- subdivision.

Powercor engaged the Centre for International Economics (**CIE**) to prepare forecasts of customer project connections for the 2015 to 2020 period. CIE prepared a report that provides a detailed description of their methodology, and is attached to the regulatory proposal.[72]

The CIE used historical data for the years from 2009 to 2013 from Powercor's submission to the AER's Category Analysis RIN, adjusted by reallocating of a proportion of Residential Complex Connection LV to Residential Complex Connection HV following the identification of an error in the categorisation of these connections in the RIN. This allocation method has been rectified as part of the 2014 Category Analysis RIN and Reset backcast RIN.

CIE established historical relationships between the historical data and economic and demographic variables for residential, commercial and subdivision categories of connections. Using correlations and econometric modelling, CIE identified that population growth, dwelling growth and economic activity are statistically significant in explaining the number of customer connection projects.

Once the drivers were identified, CIE forecast the number of connection jobs using independent forecast data, in particular:

- for gross state product (**GSP**), CIE used the forecast by the AEMO that predicts that GSP will accelerate over the next few years before easing back towards more normal growth rate by the end of the 2016–2020 regulatory control period; and
- for the number of dwelling approvals, forecasts from the Victorian Department of Transport, Planning and Local Infrastructure which suggest that there will be a similar level of dwelling approvals over the 2016–2020 regulatory control period compared to the average over 2009–2013, and a moderately higher level of dwelling approvals compared to more recent years.[73]

Powercor mapped the CIE forecasts of jobs per AER connection category to its internal reporting categories, i.e. function codes. These were then multiplied by the unit rate in each function code to obtain the forecast expenditure. The unit rate was calculated by dividing the total expenditure by the total number of jobs in each function code for the period 2011 to 2014.

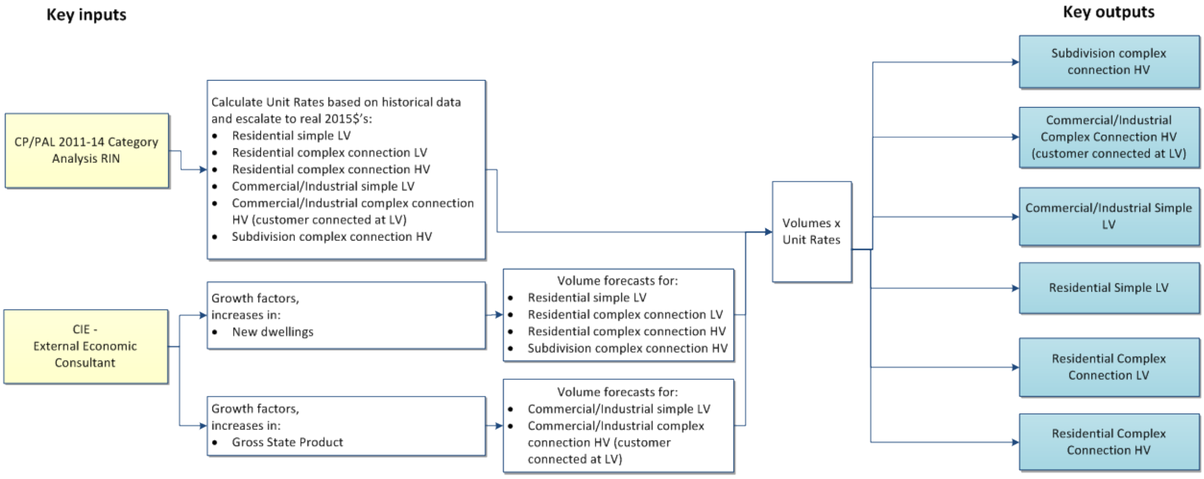
The unit rate therefore reflects historical costs for similar projects where the materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

An overview of the forecasting process for these high-volume connections is shown in figure 5.2.

[72] CIE, *Forecasting connection projects for CitiPower and Powercor*, November 2014.

[73] CIE, *Forecasting connection projects for CitiPower and Powercor*, November 2014, pp. 32-33.

Figure 5.2 Overview of economic forecast process



Source: Powercor

Low volume categories of connections

Powercor has undertaken a bottom-up build of the categories of connections where there are typically low volumes. The bottom-up forecasts have been prepared for the following connection categories:

- commercial/industrial connections connected at HV;
- embedded generation; and
- recoverable works (reported as quoted services).

The preference for using bottom-up build rather than establishing relationships with economic drivers is that the projects are often unrelated to broader activity in the economy and may be driven by government policy or specific customer needs.

To establish the forecasts, Powercor has broken the forecasting into the following components:

- projects that cost $2.5 million or more; and
- projects that cost less than $2.5 million.

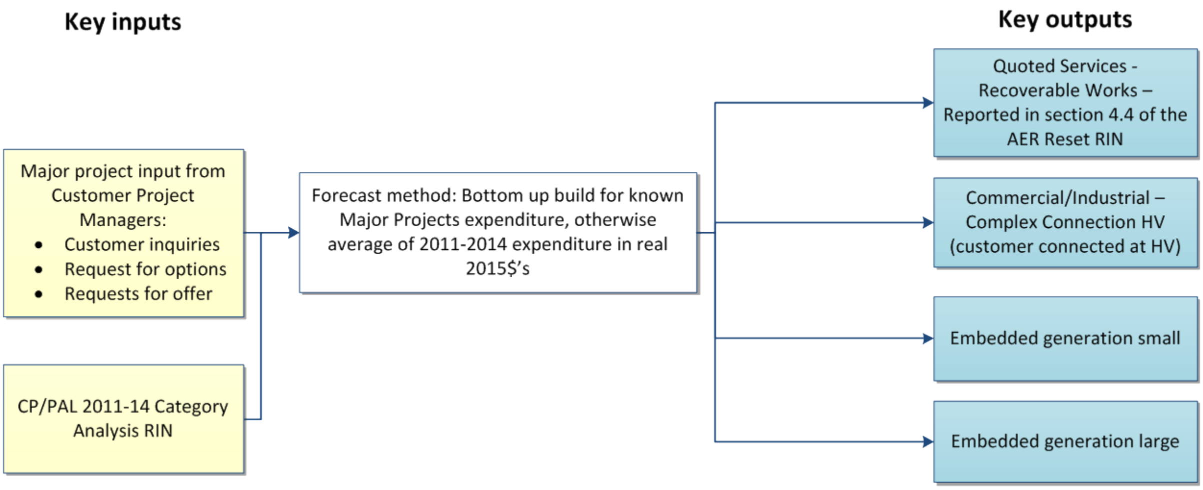
For projects that cost $2.5 million or more, Powercor has identified projects where the customer has made initial enquiries into the business, or requested options for connections or a connection offer. Based upon correspondence with the customer, Powercor has assessed that the project is highly likely to proceed and have included the connection in the forecast. The expenditure is based upon estimates from a supplier.

For those connection categories where there is currently no known major project in the latter years of the 2016–2020 regulatory control period, Powercor has assumed expenditure based on the average major project expenditure in that category for the 2011-2014 period.

Powercor considers that there are a fairly consistent number of smaller projects that cost less than $2.5 million in these connection categories. Therefore, Powercor has forecast the amount of expenditure for connections based on the average expenditure for non-major projects for the 2011-2014 period. The historical expenditure reflects Powercor's use of competitive tendering processes to source materials, contract labour and services, and is reflective of risks and uncertainty that were borne in undertaking the projects.

An overview of the bottom-up forecasting approach is shown in figure 5.3.

Figure 5.3 Overview of bottom-up build process



Source: Powercor

Attached is the *Customer connections model* used to forecast new customer connections and customer driven works.

5.2.5 Gifted assets

Guideline 14 currently regulates connection services. In particular, it makes connection and augmentation works contestable in accordance with Powercor's licence conditions – Powercor is required to call for tenders to construct the works from at least two other persons who otherwise compete for such works, unless the customer agrees with Powercor that a tender is not required.[74] This means that customers can elect to use a third party Approved Contractor,[75] rather than Powercor, to undertake the connection work on 'greenfield assets'.

Where a third party provider completes the construction of a greenfield asset that it has funded, then Powercor may acquire the asset as a 'gifted asset' once it is connected to the distribution network. Powercor may then pay a rebate to the customer or developer for the asset.

The costs of the rebate are included within the proposed capital expenditure for this expenditure category. The forecasts for rebates have been calculated as the average of the actual rebates in the 2011-2014 period, by function code.

The gifted asset is included in the Regulatory Asset Base at zero value. The asset is then maintained in accordance with Powercor's asset management policies.

5.3 Historic spend

To date, Powercor has connected over 47,000 net additional customers connect to its network in the 2011–2015 regulatory control period. The majority of these connections were smaller residential, industrial and commercial connections.

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74 Powercor also provides the customer the option of conducting the tender process themselves.

75 Eligible Approved Contracts are accredited by Powercor. Customers are required to select an accredited Approved Contractor.

Powercor has completed some large customer connection projects and customer-driven works during the 2011–2015 regulatory control period including:

- connection of the Oakland Hills windfarm in the southern Grampians area;
- connection of the Mortons Lane windfarm in the southern Grampians area;
- connection of the Leonard's Hill windfarm near Ballarat;
- relocation of sub-transmission lines for the duplication of the Princes Highway west of Geelong;
- relocation of a zone substation for a large industrial customer in the Wimmera region;
- connection to the high voltage network of a new large industrial customer near Deer Park in the western suburbs of Melbourne; and
- connection to the high-voltage network of a new processing plant for an agribusiness near Mildura.

Overall, Powercor is forecast to underspend its connections and customer driven works regulatory allowance in the 2011–2015 regulatory period by 14 per cent. Similar to augmentation expenditure, Powercor has observed a lower than expected level of customer connection gross expenditure as a result of the GFC. While there was a lagged effect to the slowdown in augmentation expenditure following the GFC as a result of committed projects being progressed, the expenditure for customer connections was lower than expected as customers quickly reacted to the changed economic environment.

The slowdown in the broader economy following the GFC is the primary reason that Powercor underspent its regulatory allowance, which was observed through the following three factors:

- the AER allowance being based on historical average costs, where the historic period included stronger growth in residential connections compared to the current regulatory period;
- costs, including gifted assets, associated with residential subdivisions also being lower compared with the earlier regulatory period that had stronger growth; and
- incremental distribution substation capacity reduced in the current period contributing to lower connection costs.

The AER connection expenditure gross allowance for the 2011–2015 regulatory control period was based on the average expenditure from 2006 to 2009. The earlier period had stronger growth in residential connections and subdivisions compared to the 2011–2015 regulatory control period. Therefore, the expected level of connections expenditure was lower than anticipated.

It is important to note that the connections forecast did not take into account forecasts for relevant economic drivers in the economy, such as building approval forecasts. These factors support the use of growth forecasts for the next regulatory period being taken into account in preparing the connection expenditure forecasts for the 2016-2020 regulatory control period.

5.4 Forecast spend

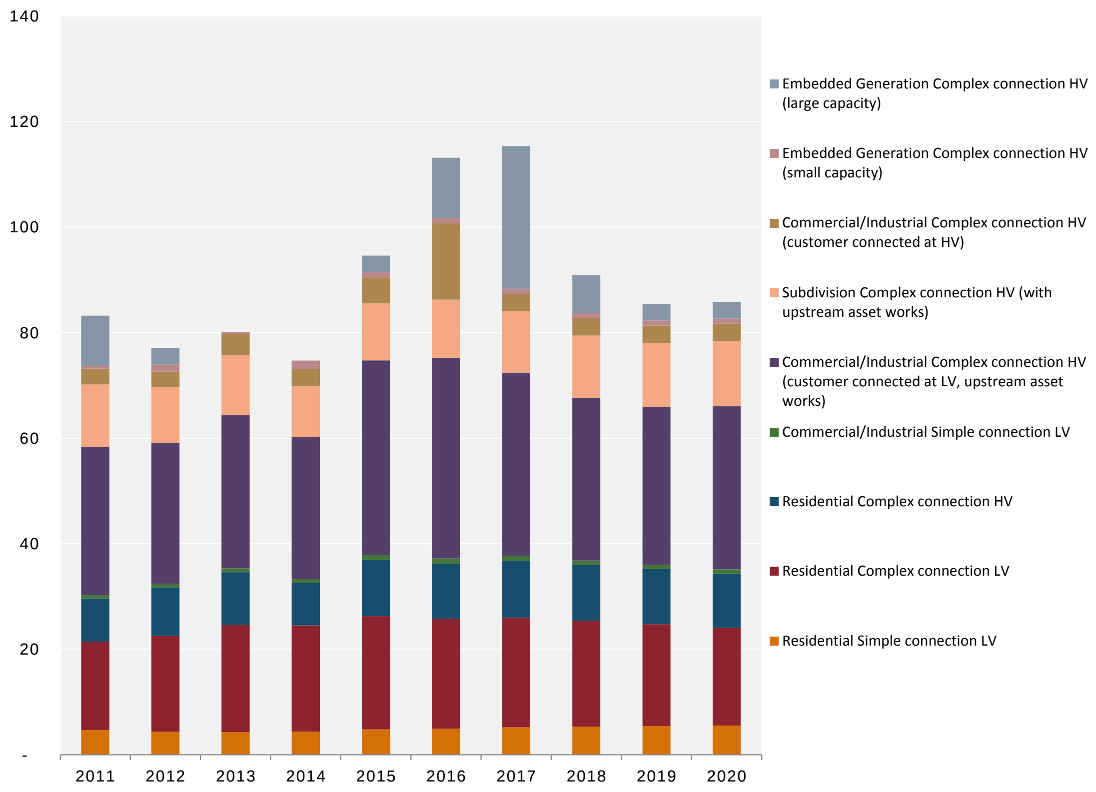
Powercor requires a 27 per cent increase in connections and customer driven works expenditure compared to its actual spend during the 2011–2015 regulatory control period. The expenditure forecast is underpinned by the following key drivers:

- supply of connection service to residential customers;
- supply of connection services to commercial and industrial customers;

- increase in supply of recoverable works to customers, including the Victorian Government's Powerline Replacement Fund to replace bare wire powerlines with insulated overhead powerlines, underground powerlines or new conductor technologies;
- increase in supply of services to industrial customers at HV, reflecting the expansion of its customers' operations such as in the dairy industry; and
- increase in supply of services to embedded generators, including new wind farms in western Victoria.

The increase in forecast expenditure is driven by particular connection categories. Figure 5.4 shows that for residential connections connected at LV and HV, and subdivisions, large changes in expenditure changes from the historical levels of expenditure are not expected in the 2016–2020 regulatory control period. A small increase in expenditure for commercial and industrial expenditure connected at LV is expected based on the expected increase in GSP. A clear step-up from historical expenditure is expected for recoverable works, commercial and industrial connections at HV and for embedded generation.

Figure 5.4 Breakdown of gross direct capital expenditure by connection type, excluding recoverable works and gifted assets ($ million, 2015)



Source: Powercor

Some of the larger customer connection projects in the categories of recoverable works, commercial and industrial connections at HV and for embedded generation are discussed below.

Powerline Replacement Fund

Following the Victorian Bushfires Royal Commission (**VBRC**) recommendations, the Powerline Bushfire Safety Taskforce (**PBST**) was established to undertake further analysis into two of the complex recommendations relating to electricity distribution networks. The PBST provided its final report to the Victorian Government in September 2011.[76]

The Victorian Government's response to the PBST's report noted that there will be still be 'black spots' in the electricity distribution network where dangerous poles and wires create an unacceptable bushfire hazard. The Government noted that:[77]

> *A process is required whereby Government, safety agencies and electricity distribution businesses can work together to identify, and replace, the most dangerous power lines. This will require an assessment of local bushfire risk; the condition of existing electricity assets; and a decision as to which replacement technology (insulation, aerial bundling, undergrounding) will yield the best result.*
>
> *The Government will contribute up to $200 million over 10 years for a program of power line conductor replacement. Based on the estimates of the Taskforce, this will replace over 1,000 km, with the final length to be replaced dependent on detailed engineering and geographic assessment. The focus will be on locations with the highest fire loss consequences.*

The locations for the replacement of the 'black spot' powerlines in the 2016–2020 regulatory control period will be determined jointly by the Victorian Government, ESV and distributors.

These works will be funded through by the Victorian Government through the Powerline Replacement Fund.

Murray Goulburn expansion

In its October 2014 annual report, Murray Goulbourn outlined new key infrastructure to ensure it has the capability and capacity it needs to meet growing demand for Australian made dairy foods, particularly in international markets. The new capital projects to be undertaken in 2015 and 2016 included:[78]

- a $74 million investment at Cobram to build a world class cheese cut and wrap facility to serve Australian and Asian consumer and food service markets; and
- a $38 million investment at Koroit and Cobram to increase capacity for production of nutritionals for growing international infant nutrition markets.

To enable these capital projects to be completed and to provide the customers' required amount of electricity, Powercor will need to establish new sub-transmission lines to the customers' sites.

Berrimal windfarm

The Berrimal Wind Farm is proposed to generate up to 72MW of electricity at a site 16km west of Wedderburn in north western Victoria. The wind farm will be constructed along a five kilometre elevated ridge exposed to consistent winds across the open Mallee Plains to the north and west.

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76 PBST, Final Report, 30 September 2011.

77 Victorian Government, Power Line Bushfire Safety: Victorian Government Response to the Victorian Bushfires Royal Commission Recommendations 27 and 32, December 2011, available from: http://www.energyandresources.vic.gov.au/energy/safety-and-emergencies/powerline-bushfire-safety-program/response-to-pbst.

78 Devondale Murray Goulburn, *Annual Report 2014*, October 2014, p. 17.

The project will comprise up to 24 wind turbine generators, installed on towers up to 120m in height, with tip height up to 185m above ground level.[79]

Powercor will develop and construct approximately 50 kilometres of 66kV sub-transmission line to connect the substation(s) at the site to the national electricity network.

A planning permit was issued by the Buloke Shire Council and approved by the Victorian Civil and Administrative Tribunal in 2014. Powercor expects construction to commence in 2017.

5.5 Material projects

Table 5.2 below provides an overview of the large programs of work over $5 million that Powercor intends to undertake during the 2016-2020 regulatory control period.

Table 5.2 Material projects for new connections requiring augmentation

Project name	Connection type	Material project no
Victorian Government Powerline Replacement Fund	Recoverable works	CUST 28
Murray Goulburn expansion	HV connection	CUST 29 CUST 30
Coonooer windfarm	Embedded generation	CUST 31
Berrimal wind farm	Embedded generation	CUST 32
Mt Gellibrand wind farm	Embedded generation	CUST 33
Project Harvest	Embedded generation	CUST 34
Yendon windfarm	Embedded generation	CUST 35

Source: Powercor

The Powerline Replacement Fund, Murray Goulburn expansion and Berrimal windfarm were discussed above. The remaining material projects are discussed in turn below.

Please note that the material business cases contain sensitive customer confidential information, including the costs of each project, and are provided to the AER on a confidential basis. The discussion below is based on information in the public domain.

Coonooer Bridge windfarm

The Coonooer Bridge windfarm is a small wind energy project located north west of Bendigo, Victoria. The windfarm will consist of six turbines and produce up to 19.4MW of energy.

79 Acciona Energy, Planning assessment report Berrimal Wind Farm, 16 December 2013, p. 1. Available from: http://www.acciona.com.au/business-divisions/energy/in-development/berrimal-wind-farm/berrimal-planning-permit-application-report.

It is jointly owned by Windlab Systems, a spin-off of CSIRO, and landholders neighbouring the project. Planning approval was received in 2013 from the Buloke Shire with a condition that construction commencement within three years and completed within five years. Construction is expected to commence late 2015 with completion in 2016.

Under the Large Scale Wind Auction process announced in February 2015, the Australian Capital Territory (**ACT**) Government has selected the Coonooer Bridge wind farm as one of the three renewable energy suppliers selected to provide a third of Canberra's electricity needs over a 20 year period.[80] The deal provides revenue certainty to the windfarm, and has triggered construction commencement.

Powercor's connection offer involves connecting the wind farm to the 66kV sub-transmission network and undertaking associated protection works and system modifications, as required, to ensure quality of supply is maintained.

Mt Gellibrand wind farm

The Mt Gellibrand wind farm is proposed to generate up to 189MW of electricity at a site located 25km east of Colac in the Otway Shire. The wind farm will be constructed on the open and partly elevated plains around the southern and western sides of Mt Gellibrand itself.

Acciona Energy obtained planning approval in 2006 and the final development plan was approved by the State Government in 2012, allowing construction to commence. Initial site establishment construction has commenced, with full construction to progress ahead of operation commencing in early 2017.[81]

Powercor will connect the windfarm to its 66kV sub-transmission network.

Project Harvest

Balfour-Beattie Investments is proposing to construct a 35MW biomass power station at Carwarp, near Mildura. The plant will burn almond hulls and shells, grape mark from local wineries and cereal straw from grain farms in the region.

Balfour-Beattie Investments has obtained funding from the Victorian Government's Regional Growth Fund[82]. The Essential Services Commission has granted an exemption allowing the bioenergy plant to sell electricity directly to neighbouring businesses, allowing them to sell their electricity at a price that makes the whole project viable.[83]

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80 Canberra Times, *Simon Corbell reveals wind farm auction winners to supply third of Canberra's electricity needs*, 5 February 2015. Available from: http://www.canberratimes.com.au/act-news/simon-corbell-reveals-wind-farm-auction-winners-to-supply-third-of-canberras-electricity-needs-20150205-136my6.html.

81 Acciona Australia, Mt Gellibrand Wind Farm, website, undated, accessed February 2015, available from: http://www.acciona.com.au/business-divisions/energy/in-development/mt-gellibrand-wind-farm.

82 Energy Business News, *$3m grant for Mildura biomass*, 24 October 2013. Available from: http://www.energybusinessnews.com.au/energy/bio-energy/3m-grant-for-mildura-biomass/.

83 Mildura Weekly, *Bioenergy plant one step closer*, 18 July 2014. Available from: http://www.milduraweekly.com.au/2014/07/18/bioenergy-plant-one-step-closer/.

To connect to the Powercor network, Powercor will need to construct 18 kilometres of sub-transmission lines as well as a new switching station. The Victorian Minister for Planning has approved the construction of the sub-transmission line. [84]

Yendon windfarm

WestWind Energy announced its intention to develop a 160MW wind farm consisting of 70 to 80 wind turbines at Lal Lal, south east of Ballarat in Victoria. The project has been split into two development sections: one north of Elaine and one east of Yendon.

The wind farm is located on 2100 hectares of farmland approximately 17kms south east of Ballarat and approximately 2kms east of the township of Yendon. The wind farm will consist of up to 40 wind turbines with a rated capacity of 2-3MW each. The total capacity of the windfarm is not expected to exceed 120MW.[85]

In December 2014, Powercor provided a non-binding offer to the customer to connect the windfarm to the sub-transmission network. It is anticipated the construction of the connection will commence in 2016 and be completed in 2017.

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84 ABC news, *Powerline approved for almond plant biomass plans*, 21 July 2014. Available from: http://www.abc.net.au/news/2014-07-21/powerline-approved-for-almond-plant-biomass-power/5610578.

85 WestWind Energy, *Application for a generation licence*, 2 December 2009, p. 4. Available from: http://www.esc.vic.gov.au/getattachment/2c8c3bf9-7522-4d35-86ca-44a64aaa6a37/Generation-Licence-Application-West-Wind.pdf.

6 Victorian Bushfires Royal Commission

The catastrophic 'Black Saturday' bushfires on 7 February 2009 were one of Australia's worst ever natural disasters.

The Victorian Bushfires Royal Commission (**VBRC**) was established to conduct an extensive investigation into the causes of, the preparation for, the response to and the impact of 15 of the most damaging, or potentially damaging, fires that burned.

The VBRC made 67 recommendations to the Victorian Government about changes needed to reduce the risk, and the consequences, of similar disasters in the future. The VBRC considered that failed electricity assets caused five of the 11 major fires that began that day, and in response eight of the recommendations proposed major changes to the State's electricity distribution infrastructure and operation management.[86]

Powercor's proposed expenditure is to continue to implement the recommendations of the VBRC, in accordance with obligations imposed, or anticipated to be imposed, on it by the safety regulator, Energy Safe Victoria (**ESV**).

This section discusses Powercor's historical and forecast VBRC expenditure as well as the approach used in calculating the forecast expenditure.

6.1 Overview

Powercor will include an additional capital expenditure category which includes capital expenditure to implement the changes to infrastructure and operations recommended by the VBRC.

The VBRC was established on 16 February 2009 to investigate the causes and responses to the bushfires which swept through parts of Victoria in late January and February 2009. The VBRC delivered its Final Report on 31 July 2010 which recommended a number of bushfire mitigation initiatives which Powercor commenced implementing during the current regulatory control period and will continue into the 2016–2020 regulatory control period.

Stakeholder engagement research undertaken by Powercor indicated overwhelming support for initiatives to reduce the risk of bushfires:

- online consumer surveys supported a small price increase to reduce the risk of fire danger, where those consumers did not support funding price rises for any other matters;[87] and
- residential focus groups and SME customer in depth interviews consistently indicated that Powercor should take all measures available to minimise any potential fire or safety related risk.[88]

"It's simple. Don't cause any fires."

"Anything to do with safety, they should know what to do and just do it."

"It's a no brainer, they have to get the safety side of things right. That's a top priority."

[86] 2009 Victorian Bushfires Royal Commission, *Final Report, Volume 2, Electricity-Caused Fires*, 31 July 2010, p 148. available from: http://www.royalcommission.vic.gov.au/Commission-Reports/Final-Report/Volume-2/Chapters/Electricity-Caused-Fire.html.

[87] Colmar Brunton Research, *Powercor Stakeholder Engagement Research - Online Customer Survey Results*, Final Report, 18 July 2014, p. 50.

[88] Colmar Brunton Research, *Powercor Stakeholder Engagement Research Report – Residential Customer Focus Groups and SME Customer Interviews*, 1 May 2014, p. 47.

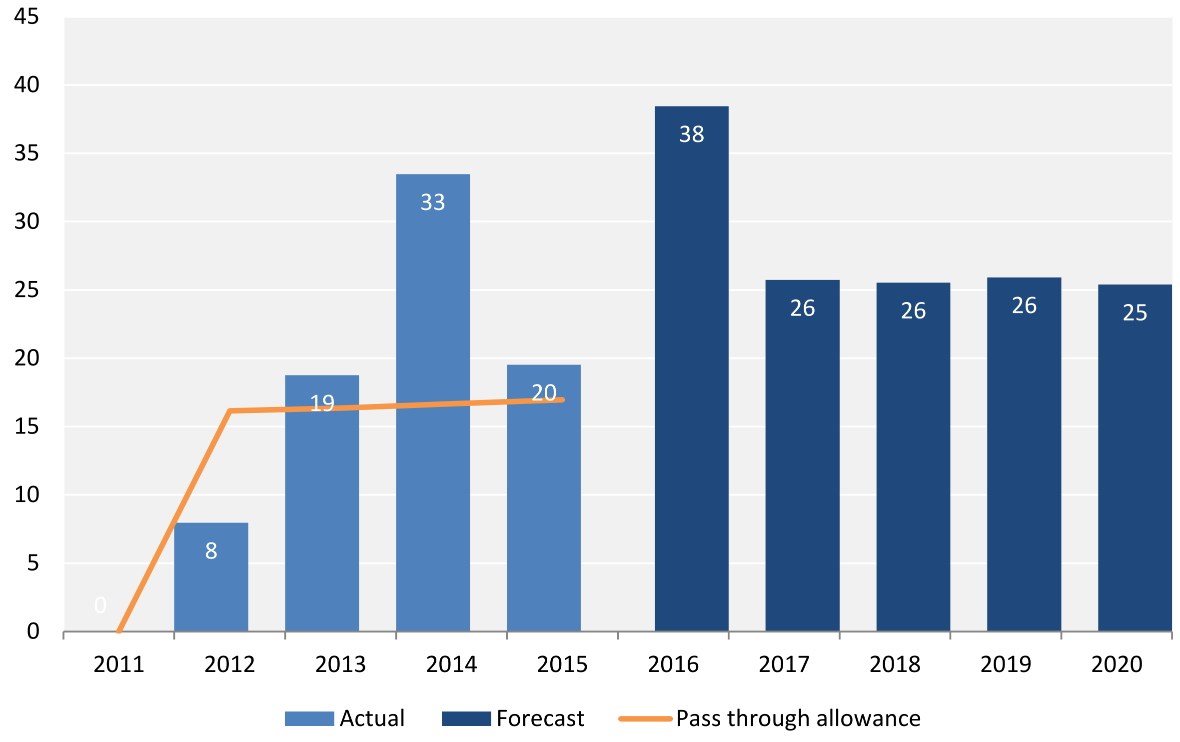
In the Directions and Priorities Consultation, Powercor queried whether it is making the right level of investment across the network to reduce the risk of fire danger, particularly in high risk and high consequence bushfire areas. A range of responses was received, including:

- the Glenelg Shire Council stated that they are currently not satisfied with the level of investment to reduce the risk of fire danger;[89]
- the City of Melton considered the level of investment to be reasonable, and noted that long term investment should occur in their area, including a program of undergrounding powerlines within high fire danger areas; and
- Wimmera Development Association noted that fire preparedness is a key community concern.[90]

At the public forums held around Victoria, stakeholders were greatly interested and supportive of the initiatives that Powercor will take to further reduce the risk of bushfires.

Figure 6.1 provides an overview of historical and forecast VBRC expenditure. Historical expenditure relates solely to costs associated with the pass through allowance provided by the AER in 2012.[91]

Figure 6.1 VBRC direct capital expenditure including real escalation ($ million, 2015)[92]



Source: Powercor

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89 Glenelg Shire Council, *Feedback questions*, 27 October 2014.

90 Wimmera Development Association, *Feedback Request—Directions and Priorities Consultation Paper*, 22 October 2014.

91 AER, *Powercor cost pass through application of 13 December 2011 for Costs arising from the Victorian Bushfire Royal Commission*, Final Decision, 7 March 2012.

92 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

It is noted that the AER no longer recognises Environment, Safety and Legal (**ESL**) as a capital expenditure category. Powercor has included non-bushfire related ESL capital expenditure in replacement capital expenditure.

The expenditure forecasts are to implement specific obligations or anticipated obligations placed on Powercor by ESV. These obligations require the forecast projects to be undertaken during the 2016-2020 regulatory control period. The project expenditure relates to:

- fitting 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 the Electricity Safety Management Scheme (**ESMS**);
- installation of new generation Automatic Circuit Reclosers (**ACR**s) to Single Wire Earth Return (**SWER**) lines to instantaneously detect and turn off power at a fault on high risk fire days, in accordance with the Bushfire Mitigation Strategy Plan (**BMP**);
- installation and trial of earth-fault current limiting equipment in zone substations to confirm the suitability of the technology for reductions in the amount of arc energy released by a phase-to-ground fault, so that such a fault is unlikely to ignite a bushfire, in anticipation of a requirement from ESV to install such equipment;
- conducting a survey of multi-circuit lines to assess whether the conductor clearance is sufficient, in accordance with the ESMS; and
- installation of spacers in aerial lines to maintain conductor clearances and stop conductor clashing in windy conditions, in accordance with the ESMS.

Powercor has been unable to forecast with accuracy all of the costs associated with anticipated VBRC related obligations that are expected to be imposed on it during the 2016–2020 regulatory control period. Therefore, Powercor proposes to categorise the following projects as contingent projects, as set out in table 6.1.

Table 6.1 VBRC related proposed contingent projects

Event	Proposed contingent capital expenditure ($ 2015)	Trigger
Installation of Rapid Earth Fault Current Limiters (REFCLs)	Approximately $63m	Imposition on Powercor of new or changed regulatory obligation in respect of earth faults
Codified areas	Approximately $235m	Imposition on Powercor of new or changed regulatory obligation in respect of high consequence bushfire ignition areas within Victoria specified as ‘codified areas’

Source: Powercor
Note: direct costs excluding real escalation

6.2 Background

Following the catastrophic Black Saturday bushfires in 2009, the Victorian Government established the VBRC to consider how bushfires can be better prevented and managed in the future.

The VBRC report made 67 recommendations, eight of which related to electricity supply assets. Two of those were of sufficient complexity that the VBRC recommended further analysis by an expert taskforce, the Powerline Bushfire Safety Taskforce (**PBST**).

Many of the VBRC recommendations are applied to distributors through ESV using its powers under the *Electricity Safety Act 1998* or other legislation. ESV has responsibility for enforcing safety-related:

- Legislation;
- regulations;
- directions;
- the ESMS; and
- relevant Australian Standards.

Obligations placed on Powercor by ESV under legislation may result in Powercor amending its ESMS, or the related BMP. Once the amended ESMS or BMP is accepted by ESV, then Powercor must comply with the revised scheme or plan as compliance is enforceable by ESV.

6.2.1 Methodology

The VBRC expenditure forecast is project-based, using a bottom-up build. Where Powercor has undertaken projects in the high bushfire risk areas (**HBRA**) in the current regulatory control period, the cost and/or volume information from those projects has been used in the forecasts for those same projects in low bushfire risk areas (**LBRA**).

Table 6.2 sets out the forecasting methodology for each VBRC project.

Table 6.2 VBRC forecasting methodology

Project	Volume estimates	Cost estimates
Armour rods and vibration dampers	Based on detailed assessment of each span using Geographic Information System (**GIS**)	LBRA: based upon HBRA project cost information for 22kV lines HBRA: based on bottom-up build for 66kV sub-transmission lines
Automatic Circuit Recloser on SWER lines	Set in BMP	Based upon HBRA project cost information
Trial of earth-fault limiting equipment	One trial proposed	Based on detailed scope and design for a zone substation
Survey of multi-circuit lines	GIS data	Based upon HBRA project cost information
Installation of spacers on multi-circuit HV lines	Based on outcomes from HBRA survey	Based upon HBRA project cost information
Multi circuit re-builds	Based on outcomes from HBRA survey	Bottom-up build based on historical costs for similar projects

Source: Powercor

Where the cost estimates are based on HBRA or historical project cost information, those costs are reflective of any competitive tendering processes to source materials, contract labour and services, and risks and uncertainty that were borne in undertaking the projects.

Greater detail on the projects and costs and volumes are provided in section 6.4.

6.3 Historic spend

In 2012, the AER approved a pass through application for Powercor relating to costs arising from the VBRC. The capital expenditure component of the pass through allowance related to the installation of armour rods and vibration dampers to specified conductors in HBRA.

While Powercor sought $69.50 million ($2012) ($74.38 million ($2015)) of capital expenditure in its pass through application, the AER approved $60.55 million ($2012) ($64.80 million ($2015)).[93]

The AER's pass through allowance did not provide for overheads. Following the activity, overheads were allocated to the costs incurred.

On a direct cost basis, Powercor will overspend the AER allowance by around $14 million during the current regulatory period. This was as a result of:

- the unit rates for installation of armour rods and vibration dampers determined by the AER being lower than those available in the market when Powercor subsequently tendered the work;
- costs of installing armour rods and vibration dampers on poles with cross-arms that were replaced as part of the usual replacement cycle incurred higher than usual costs as a result of the additional design and materials for those poles; and
- volumes for spacers being higher than anticipated in the pass through application.

It is also noted that Powercor will not achieve strict compliance with the obligation to install vibration dampers and armour rods to specified conductors in accordance with the Victorian Electricity Supply Industry (**VESI**) standards by 1 November 2015 in HBRA.

At the end of 2015, Powercor estimates that 91 per cent of the 193,090 spans identified in the HBRA will have armour rods or vibration dampers fitted. The remaining 18,153 spans are on 66kV sub-transmission lines or 22kV spans where Powercor had access issues or other difficulties in installing the equipment. These spans will be completed in 2016.

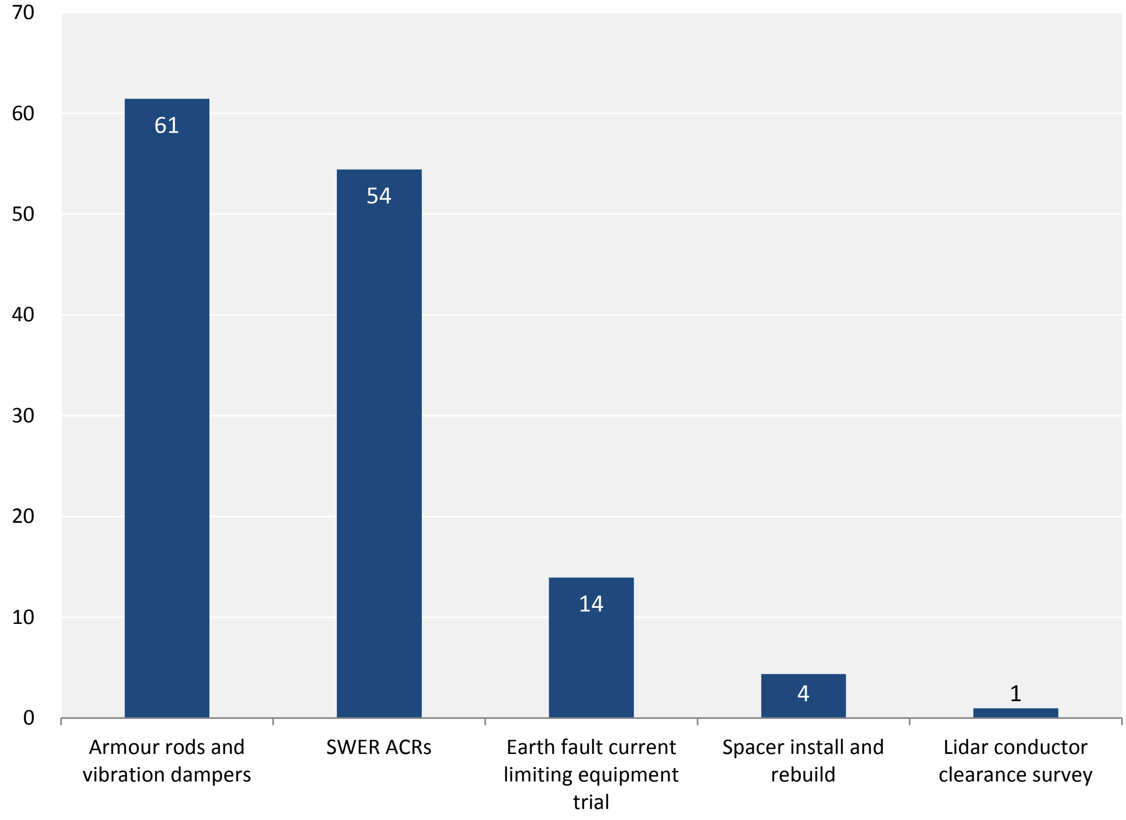
6.4 Forecast spend

The forecast expenditure for VBRC relates to specific projects that Powercor is obligated to undertake, or anticipates to be obligated to undertake, during the 2016–2020 regulatory control period.

An overview of the expenditure, by project, is shown in figure 6.2. The distribution services to be provided by the proposed assets are network services.

[93] AER, *Powercor cost pass through application of 13 December 2011 for costs arising from the Victorian Bushfire Royal Commission – Final Decision*, 7 March 2012, p. 94. (confidential version of document).

Figure 6.2 Powercor VBRC direct capital expenditure by program ($ million, 2015)



Source: Powercor
Note: direct costs excluding real escalation

Table 6.3 provides an overview of the source of the obligation that has been imposed, or is anticipated to be imposed, on Powercor. A description of each of these projects is then provided in turn below.

Table 6.3 Source of obligations for VBRC expenditure

Project name	Obligation source
Armour rods and vibration dampers	ESMS
ACR on SWER lines	BMP
Earth fault limiting equipment trial	To be confirmed
Lidar conductor clearance survey	ESMS
Spacers in aerial lines	

Source: Powercor

A regulatory instrument has not been issued to Powercor in relation to earth-fault current limiting equipment. It is anticipated, however, that a requirement for Powercor to achieve a particular standard in response to earth faults will be imposed during the 2016–2020 regulatory control period.

Armour rods and vibration dampers

Powercor is required to install armour rods and vibration dampers in low bushfire risk areas by 1 November 2020.

Recommendation 33 of the VBRC proposed that:[94]

> *The State (through Energy Safe Victoria) require distribution businesses to do the following:*
>
> - *fit spreaders to any lines with a history of clashing or the potential to do so*
> - *fit or retrofit all spans that are more than 300 metres long with vibration dampers as soon as is reasonably practicable.*

Subsequently, ESV issued a Direction on 4 January 2011 under section 141(2)(d) of the *Electricity Safety Act 1998*, which required Powercor to ensure that its ESMS provides that:[95]

> *(a) Armour rods are to be fitted to all conductors as specified in the drawings VX9/7037 and VX9/7037/1 of the Victorian Electricity Supply Industry Overhead Line Manual, Volume 1 or other equivalent or higher standard approved by Energy Safe Victoria;*
> *(b) Vibration dampers are to be fitted to all conductors as specified in the drawings VX9/7037 and VX9/7037/1 of the Victorian Electricity Supply Industry Overhead Line Manual, Volume 1;*
> *(c) Armour rods and vibration dampers are to be fitted to all other spans where there is evidence of wear of the conductor or armour rod due to vibration;*
>
> *…*
>
> *(e) A program to ensure that all locations requiring armour rods or armour rods and vibration dampers to be fitted is completed:*
>
> - *In hazardous bushfire risk areas — before 1 November 2015; and*
> - *In all other areas — before 1 November 2020*.
>
> *In developing the program, priority shall be given to those spans exposed to conditions conductive to vibration with consideration for the length of time those lines have been exposed to those conditions and the fire risk of the location in which they are installed.*

Armour rods are protective devices designed to reduce wear on conductors at the contact points with insulations and conductor ties, vibration dampers are intended to reduce conductor vibration and therefore the impact of this vibration on conductors and ties.

In its letter to ESV on 1 February 2012, Powercor set out the program of work to install armour rods and vibration dampers. In HBRA, the program was planned to start in 2012 with completion in the first half of 2015. In LBRA, the fitting of program was planned to start in 2016 and being completed in the first half of 2019.[96]

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[94] 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 30.

[95] ESV, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of armour rods and vibration dampers*, 4 January 2011.

[96] CitiPower and Powercor, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of armour rods and vibration dampers,* 1 February 2011.

Powercor subsequently updated its ESMS to include the requirements of the Direction.

Volume and cost of armour rods and vibration dampers

Powercor has been in discussions with ESV regarding the completion of the HBRA program by November 2015. This program is behind schedule and over-budget. Of the 193,090 spans requiring armour rods and vibration dampers, Powercor will not complete 12,733 spans on 22kV lines, or any of the 5,420 spans on 66kV sub-transmission lines. These remaining 18,153 spans will be completed in 2016.

The unit costs in HBRA have been calculated as follows:

- where the work is to be carried out on a 66kV sub-transmission line, the unit rate is based on the contractual costs for labour per span requiring a visit, plus field operating costs for switching in the network for the planned outage; and
- where the work is to be carried out on a 22kV HV feeder, the unit rate is based on the expected unit rate in 2015 reflecting the historical unit rate, uplifted for those remaining feeders that are 'exception' locations that were not completed due to access restrictions and/or difficulties.

In LBRA, Powercor has estimated that there are 113,228 spans where armour rods and vibration dampers are required to be installed. The figure is based on a detailed analysis of the characteristics of each span in the network using the GIS system.

The unit cost is based on the historic average cost per span, which takes into account the start-up costs associated with the program, such as the re-tendering for this program of work, contractor training and mobility solution, design and work issues.

ACRs on SWER lines

Powercor is required to install 1,088 ACRs on SWER lines during the 2016–2020 regulatory control period.

Recommendation 27 of the VBRC proposed that:[97]

> *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 PBST's final report considered five broad approaches to addressing recommendation 27, including:

- undergrounding powerlines;
- insulating overhead powerlines;

97 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010, p. 29.

- deploying new protection technologies (REFCLS and new generation SWER ACRS);
- deliberately turning off powerlines on high fire days; and
- installing stand-alone power suppliers and permanently turning off powerlines although this.

The PBST recommended widespread deployment of new protection network technologies together with the targeted replacement of powerlines with underground or insulated cable in the highest fire loss consequence areas.

ESV issued a Direction to Powercor on 5 April 2012 under section 141(2)(d) of the *Electricity Safety Act 1998* to install new generation protection devices to instantaneously detect and turn off power at a fault on high risk fire days. The Direction required that Powercor's BMP provides that:[98]

> *(a) The location of all SWER ACRs whose protection settings and reclose functions cannot be remotely controlled by Powercor's SCADA system, with this information to be provided by 30 April 2012;*
> *(b) The location of all SWER fuses downstream from the SWER isolating transformer, excluding distribution substation fuses, with this information to be provided by 30 April 2012;*
>
> …
>
> *(d) A program is developed by 31 August 2012 to ensure all locations identified in (a) and (b) have ACRs, whose protection settings and reclose functions can be remotely controlled by Powercor's SCADA system*
> *(e) That sufficient ACRs are installed by 30 November 2012 to eliminate the need to attend and manually suppress the automatic reclose function on any SWER lines in the areas of highest 80 percent fire loss consequence on total fire ban and code red days.*
>
> …

In 2012/13, Powercor replaced 179 SWER ACRs located in the highest 80 per cent consequence areas. The expenditure was captured in the replacement category for the 2011–2015 regulatory control period.

The Direction also required Powercor to outline a program of work to complete the installation of new generation SWER ACRs in all remaining areas. In its letter to ESV on 28 August 2012, Powercor set out the program of work to install new generation ACRs in all remaining areas by 2020. This plan is also contained in Powercor's BMP, thus satisfying the Direction.[99] Powercor is therefore obligated to complete these works.

Volume and cost of ACRs on SWER lines

In Powercor's letter to ESV dated 28 August 2012, Powercor set out a plan to replace 664 existing SWER ACRs in the lowest 20 per cent fire loss consequence areas and 424 installations on SWER networks that currently do not have an ACR. The letter indicated that the program would commence in 2016 and be completed in 2020. The nominal program indicated the following program of work:

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98 ESV, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Installation of new generation electronic automatic circuit reclosers (ACRs) to single wire earth return (SWER) lines*, 5 April 2012.

99 Powercor, *Bushfire Mitigation Strategy Plan, 2012-13*, 28 August 2012, p. 26.

Table 6.4 Program of work to install SWER ACRs

Period	2016	2017	2018	2019	2020
Volume	217	217	218	218	218

Source: Powercor, *Re – Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Installation of new generation electronic automatic circuit reclosers (ACRs) to single wire earth return (SWER) lines*, 28 August 2012; Powercor, *Bushfire Mitigation Strategy Plan, 2012-13*, 28 August 2012, p. 26.

The volumes in table 6.4 remain relevant to Powercor.

As Powercor has installed SWER ACRs during the current regulatory control period, it has used that average unit costs in its forecasts. The unit costs are consistent with those reported by Powercor in the Category Analysis RIN, escalated to $2015.

Earth fault current limiting equipment trial

Powercor does not currently have an obligation to install earth fault current limiting equipment in its network. However, it is anticipated that an obligation will be imposed during the 2016–2020 regulatory control period.

Recommendation 27 of the VBRC proposed that:[100]

> *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 <u>or other technology</u> 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 <u>or other technology</u> 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.*
>
> [Emphasis added]

In its 2011 report, the PBST identified rapid earth fault current limiters (**REFCLs**) that operate on 22kV powerlines as a new protection technology that can detect and turn off power at a fault almost instantaneously. It concluded that the most cost-effective solution to reduce the likelihood of bushfires starting by powerlines is the widespread deployment of new protection network technologies, namely REFCLs and ACRs on SWER lines.[101]

In response to the PBST report which identified the use of REFCLs and SWER ACRs to reduce the likelihood of powerlines starting bushfires, the Victorian Government stated in its response to the PBST report that:[102]

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100 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 29.

101 Powerline Bushfire Safety Taskforce, *Final Report*, 30 September 2011.

102 Department of State Development, *Business and Innovation, Power Line Bushfire Safety: Victorian Government Response to The Victorian Bushfires Royal Commission Recommendations 27 and 32*, December 2011, available from:

> *As recommended by the Taskforce, the Government will now require electricity distribution businesses to install both of these devices across the State over the next decade. Electricity distribution businesses will be required to specify, through their Bushfire Mitigation Plans, the location and timing of asset roll-out. Progress against these Bushfire Mitigation Plans will then be reviewed by Energy Safe Victoria on an annual basis. This is estimated by the Taskforce to cost approximately $500 million over 10 years.*

The $500 million package referred to by the Victorian Government was outlined in the PBST report, and contained 108 REFCLs to be installed in extreme, very high and hire fire loss consequence areas, in addition to the installation of approximately 1,300 new generation SWER ACRs and replacement of 110km of powerline.

In October 2014, the Victorian government claimed that it has:[103]

> *successfully completed over 200 world-first tests of new network protection technologies (the Rapid Earth Fault Current Limiter, or REFCL), offering potential for cost-effective bushfire risk reduction across Victoria.*

Use and trials of REFCLs

The PBST noted that REFCLs have been used in Europe since the early 1990s to improve supply reliability, mainly on underground cable networks. According to the PBST, the primary purpose of REFCLs has been to gain improvements in supply reliability and reduction of cable damage from faults. Fire safety has not been a material concern in parts of Europe.[104] It is important to note that the application of the device in the Powercor rural network will not be to improve reliability as the faulty line will not be able to remain in service, as is the case in the European applications.

Trials in Australia are being used to determine whether the installation of a REFCL may further reduce the possibility of a bushfire starting. The list of trials includes:

- arc ignition mitigation testing of the Swedish Neutral's 'Ground Fault Neutraliser' (**GFN**) in United Energy's Frankston South zone substation in 2013 and 2014;
- installation of a REFCL in AusNet Services' Woori Yallock zone substation; and
- the planned installation of a REFCL in AusNet Services' Kilmore South zone substation in 2015, where Powercor is participating in the program.

Powercor trial of REFCL

Powercor intends to trial the REFCL in its Woodend (**WND**) and Gisborne (**GSB**) zone substations in 2016. This trial would allow it to undertake detailed scoping and preliminary field tests, as well as understand how the REFCLs in adjacent zone substations interact with each other when one is activated.

Powercor will also obtain experience through its participation in AusNet Service's trial in Woori Yallock and Kilmore South using GFN and other competing technologies.

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http://www.energyandresources.vic.gov.au/energy/safety-and-emergencies/powerline-bushfire-safety-program/response-to-pbst.

[103] Department of State Development, Business and Innovation, *Victoria's Energy Statement*, October 2014, p. 10.

[104] Powerline Bushfire Safety Taskforce, *Final Report*, 30 September 2011, pp 47-48.

In addition, Powercor wishes to understand the benefits and challenges of installing a REFCL, particularly given the network vulnerabilities to the over-voltages created by REFCL responses to earth faults so that customer supply is not disrupted nor fires started on:

- surge arrestors;
- old insulators;
- aged distribution transformers; and
- cable head poles.

The trial would enable Powercor to be in a position to design, install and operate REFCLs, should the technology demonstrate that it is able reduce the possibility of a bushfire starting.

Powercor has estimated the cost of installing the REFCL based on a detailed scope and preliminary design undertaken for the installation of a REFCL in a zone substation, which was informed by its involvement with AusNet Services on REFCL technology trials.

That estimate has been applied to the WND and GSB zone substations, taking into account variations with the size of the associated network and the particular characteristics of each zone substation and the network between these adjacent zone substations.

This project is further described in the material project *VBRC 36 Install REFCL's in HBRA*.

Lidar conductor clearance survey

Powercor is required to undertake a survey of multi-circuit lines in LBRA during the 2016–2020 regulatory control period to identify all spans that do not comply with the separation requirements, and to then install a spacer or rebuild the line for those spans that do not comply.

Recommendation 33 of the VBRC proposed that:[105]

> *The State (through Energy Safe Victoria) require distribution businesses to do the following:*
>
> - *fit spreaders to any lines with a history of clashing or the potential to do so*
> - *fit or retrofit all spans that are more than 300 metres long with vibration dampers as soon as is reasonably practicable.*

Subsequently, ESV issued a Direction to Powercor on 4 January 2011 under section 141(2)(d) of the *Electricity Safety Act 1998*, which required Powercor to ensure that its Electricity Safety Management Scheme provides that:[106]

> *(a) Low voltage spreaders shall be fitted to all spans of bare low voltage conductor in hazardous bushfire risk areas;*
>
> *…*
>
> *(d) The separation between all conductors, with the exception of insulated conductors, shall be maintained in accordance with the minimum separation required in Section 10.3 – Conductors on the same supports (same or different circuits and shared spans) of the current release of the Energy Networks Association document C(b)1 – Guidelines for Design and Maintenance of Overhead Distribution and Transmission Lines;*

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[105] 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 30.

[106] ESV, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines*, 4 January 2011.

(e) *A program to identify all spans that do not comply with (d) above shall be developed by 1 February 2011;*

(f) *All spans that do not comply with the requirements of (d) above shall be constructed to comply, or fitted with spacers:*

- *in hazardous bushfire risk areas – before 1 November 2015; and*
- *in all other areas – before 1 November 2020.*

…

On 1 February 2011, Powercor responded to ESV outlining its plan to undertake a survey of spans in HBRA by July 2014 and for identified works to be completed by 1 November 2015. Additionally, Powercor outlined that the survey in LBRA would commence in the second half of 2015 and completed by July 2019. The survey would assess all spans of bare open wire multi-circuit lines. The timetable would allow completion of any identified works to install spacers or reconstruct the span to comply with the separation requirements by 1 November 2020.[107]

Powercor amended its ESMS to include the requirements of the Direction, thus satisfying the Direction. Powercor is therefore obligated to complete these works.

Volume and cost of survey

The ESV Direction contained a requirement for Powercor to develop and program to identify all spans that do not comply with the separation requirements outlined in the Energy Networks Association (**ENA**) document C(b)1 – Guidelines for Design and Maintenance of Overhead Distribution and Transmission Lines.

The methodology to identify non-compliance spans was set out in Powercor's letter to the ESV on 1 February 2011. The letter noted that to ascertain the clearance assessment of multi-circuit spans, the three-dimensional location all points of attachment for each conductor and the mid-span locations must be determined. Design calculations would then be required to allow for expansion and contraction of the conductors under variations in the ambient temperature and electrical load at nominal stringing tension.[108]

Powercor estimates that 550km of lines will need to be surveyed in 2016. The length of line has been assessed using the GIS system.

The survey will be conducted in 2016 using Lidar technology, which involves specially equipped vehicles following the route of the relevant sections of the network to capture the relevant information.

As Powercor tendered for and engaged a contractor to conduct a survey of the multi-circuit spans during the current regulatory control period, it has used the contract rates from that survey plus Powercor design costs in forecasting the expenditure for the LBRA survey.

Spacers in aerial lines

The Direction requiring that a survey of multi-circuit lines be undertaken also required that spans that do not comply with the required clearances be constructed to comply, or fitted with spacers.

[107] CitiPower and Powercor, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines,* 1 February 2011.

[108] CitiPower and Powercor, *Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines,* 1 February 2011.

In the 2011–2015 regulatory control period, Powercor undertook a survey in HBRA. Where spans were identified as not being in accordance with the ENA Guidelines, a spacer was required to be installed or the line reconstructed. Powercor has been unable to rebuild spans that could not be addressed using a spreader in the current regulatory control period given the lead time for design works to reconstruct the line. The reconstruction of these lines will be carried out in 2016 and 2017.

Volume and cost of spacers

The volume of spans estimated to not comply with the separation requirements in LBRA is 900. This volume is based on Powercor's experience in the HBRA portion of the network where 10,400 multi-circuit spans were surveyed and 7.8 per cent were found to not be compliant. Of those spans:

- 30 per cent were able to be fitted with a spacer, as those spans were either 22kV or 11kV; and
- 70 per cent required a rebuild as the spans involved 66kV sub-transmission line and there is currently no spacer that can be used on such lines.

For LBRA, there are 11,531 multi-circuit spans, and therefore the same ratios from the previous survey have been applied, as shown in table 6.5, together with the rebuilds on 66kV sub-transmission lines in HBRA areas.

Table 6.5 Volumes of works relating to spacers in aerial lines

Period	2016	2017	2018	2019	2020
Installation of spacers	0	270			0
Rebuild span - LBRA			210	210	210
Rebuild span - HBRA	284	284			

Source: Powercor

In relation to the unit cost per span to install a spacer, Powercor has used the average cost per span that it incurred in 2014 for the installation of spacers in HBRA.

The cost of rebuilding spans has been based upon the historical cost of replacing the cross-arm associated with sub-transmission lines on a multi-circuit span, to ensure that the clearance space between the sub-transmission line and the 22kV feeders meets the minimum separation requirements. The rebuild cost is consistent with the 66kV cross-arm replacement cost in the replacement capital expenditure category, together with design costs for each span.

6.4.1 Contingent projects

Not all possible VBRC-related expenditure is included in this capital expenditure category. Powercor has nominated two other potential areas of VBRC-related expenditure as contingent projects. These projects relate to expenditure that is required to be undertaken during a regulatory control period but which cannot be predicted with reasonable certainty at the start of the period.

The capital expenditure component of a proposed contingent project must be greater than $30 million. The two VBRC-related projects that Powercor proposes to nominate as contingent projects are:

- installation of additional REFCLs into Powercor's network; and

- special construction and reconstruction requirements for overhead powerlines in ‘codified areas’.

These projects are briefly discussed in turn below, with a detailed description provided in Appendix K.

REFCLs

The PBST has recommended the installation of REFCLs in extreme, very high and high fire loss consequential areas. Trials of the technology are being undertaken in Australia to determine whether a REFCL may reduce the possibility of a bushfire starting.

Following the outcome of the trials, Powercor may be required to achieve a particular standard on the network in response to earth faults. This trigger for this project would be the imposition on Powercor of a new or changed regulatory obligation in respect of earth faults.

Codified areas

Powercor is expecting to be required to comply with a new regulation in relation to ‘codified areas’. It is intended that a codified area would require special treatment in the construction or reconstruction of overhead power lines. The specifics of the regulations are currently the subject of discussions between ESV, PBST, AusNet Services and Powercor, and are likely to be finalised during 2015. The trigger for the project would be the imposition on Powercor of a new or changed regulatory obligation in respect of high consequence bushfire ignition areas within Victoria specified as ‘codified areas’

7 IT and communications

As Powercor moves towards embracing a network of the future, IT provides critical support to enable integrated digitalisation across all aspects of its operations and network.

By prudent and efficient investment in, and management of, its IT and communications systems and infrastructure, Powercor is able to provide safe and reliable services that supply energy to its customers.

IT is used to support critical business direction across Powercor, using solutions that deliver innovation through pragmatic use of technology and deliver better customer service.

Powercor recognises its customers' need for access to energy consumption information that allows them to self-determine their energy usage practices and demand. A key focus for Powercor is to provide customer services that make it easier for its customers to make informed choices through access to real time information across multiple platforms.

This section discusses Powercor's historical and forecast Information Technology (**IT**) and communications expenditure as well as the approach used in calculating the forecast expenditure.

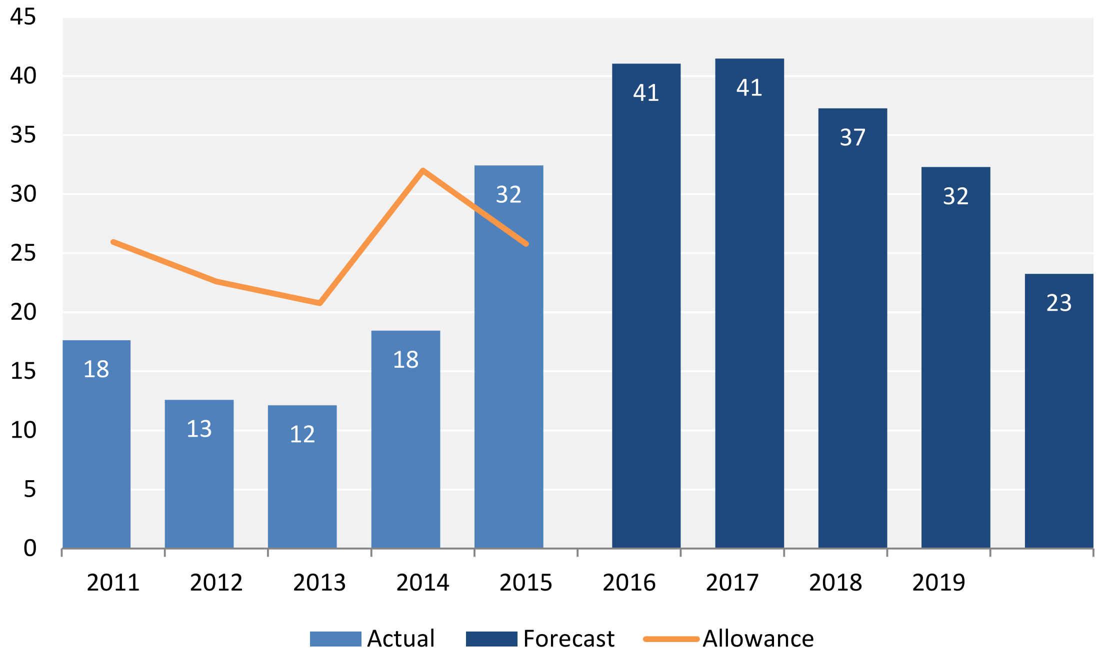
7.1 Overview

Powercor's capital expenditure forecasts for IT and communications support the directions and strategies of the business. IT services provide the critical energy management, metering and information services that enable the efficient and reliable delivery of energy to customers. Underpinning these services are IT support services for network; asset management; works management; metering and corporate IT services that provide the architecture and information to successfully operate the network business.

The foundation of these IT services is an IT infrastructure of hardware and applications, as well as devices, that must be proactively, prudently and efficiently managed throughout their lifecycle to meet required business service levels.

An overview of the historical and forecast IT and communications expenditure is shown in figure 7.1. This figure does not include historical IT expenditure to support the smart meter deployment which has been recovered through a separate regulatory process.

Figure 7.1 IT and communications direct capital expenditure ($ million, 2015)[109]



Source: Powercor

Powercor's forecasts for IT capital expenditure are broken down into a number of streams[110], representing investment in a number of key capabilities and underlying infrastructure that are critical in supporting business operations to provide safe, reliable and efficient energy services to customers. Investment in the following streams is necessary to maintain current service levels and systems while also investing in new technology to support industry changes:

- **compliance-**maintaining regulatory, statutory, market and legal compliance via investment in systems, data, processes and analytics to provide the functionality and reporting capability to efficiently comply with statutory and regulatory obligations;
- **currency and capacity-**maintaining vendor support for solutions and core software within acceptable and consistent versions and proactively ensuring that business needs and service definitions are fulfilled using a minimum of computing resources, and that applications have the capacity to support business volumes within service level targets;
- **customer engagement-**investment in systems and capabilities that support the increasing complexity of market relationships and customer needs. Responding to evolving industry forces, energy market and industry changes that are being progressed by regulators to increase innovative participation by customers in the market;
- **device replacement-**optimising the investment in end user devices to enable workforce operability whilst optimising cost and performance;
- **infrastructure-**prudently optimising asset lifecycles of infrastructure assets to ensure agreed service levels can be met at the lowest lifecycle cost and supporting normal business growth;

[109] 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

[110] CHED Services, *IT Service Delivery, Investment Stream Strategies 2016-2020 stories*, April 2015.

- **security-**ensuring customers continue to receive a reliable distribution of controlled power, by monitoring, managing and mitigating threat of cyber and network security breaches in a prudent manner; and
- **smarter networks-**enabling networks for the future through targeted investment in technologies that maintain and improve customer service standards and enable new and innovative services.

These streams are all discussed in further detail in the forecast expenditure section below.

Powercor's forecast expenditure is reflective of customer needs; encapsulates changes in the regulatory frameworks; and offers the business a forward thinking and innovative approach to the needs of a 2020 customer and in doing so balances a prudent approach to the introduction of new technology and the exploitation of existing systems.

A key focus of Powercor's investment is to facilitate customer choices in an innovative and competitive energy market. This emerging market need will drive requirements for new systems, processes and capabilities over the next five years.

To respond to the growing customer demand for greater pricing flexibility and access to information Powercor will implement a Customer Relationship Management (**CRM**) system together with replacing the existing billing system to support and manage customer access to their information and support more personalised service, which is supported by its stakeholders. For example, in response to the Directions and Priorities consultation, one of Powercor's customers sought access to smart meter usage records to assist understanding his energy sources, noting that:[111]

> *With the growing complexity in tariff types only a thorough analysis of the usage patterns for a customer can provide an informed decision as to which tariff is most cost effective for the customer.*

Similarly, the Wimmera Development Association sought greater promotion of smart meter data to enable greater consumer choice, noting: [112]

> *Promotion of the data available on real time power usage (via smart meter readings) would enable consumer choice and informed decision-making about power use. There seems to be little appreciation of the accessibility or processes to utilise this data.*

Customers are also keen for Powercor to continue to innovate, as it moves along the journey to a smarter grid by building upon the information available through the deployment of smart meters. Stakeholders consider that a smarter grid is a highly appealing and necessary area for investment. In response to the Directions and Priorities, a Powercor customer noted that: [113]

> *Emerging technologies such as small scale renewable and small scale battery storage have the ability to significantly reduce peak demand and should be encouraged as part of a smart grid.*

Through interviews with residential customer focus groups and SMEs, stakeholders indicated that their future needs would be best met with a smart grid to enable choices and flexibility as well as the efficient upgrade of ageing infrastructure. Smart grid was seen as an area that is highly worthy of

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111 Adrian Power, Email submission to Directions and Priorities, 21 October 2014. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/1.-Adrian-Power-21-October-20141.pdf.

112 Wimmera Development Association, Feedback request – Directions and Priorities consultation paper, 22 October 2014, p. 2.

113 Les Kretzschmar, Email submission to Directions and Priorities, 31 October 2014. Available from: http://talkingelectricity.com.au/wp/wp-content/uploads/2014/11/17.Les-Kretzschmar-31-October-2014.pdf.

investment to residential customers, and was viewed positively by all SME customers due to the flexibility and opportunity it provides SMEs to generate their own electricity and additional electricity which could be returned to the grid for a financial benefit.[114]

7.2 Background

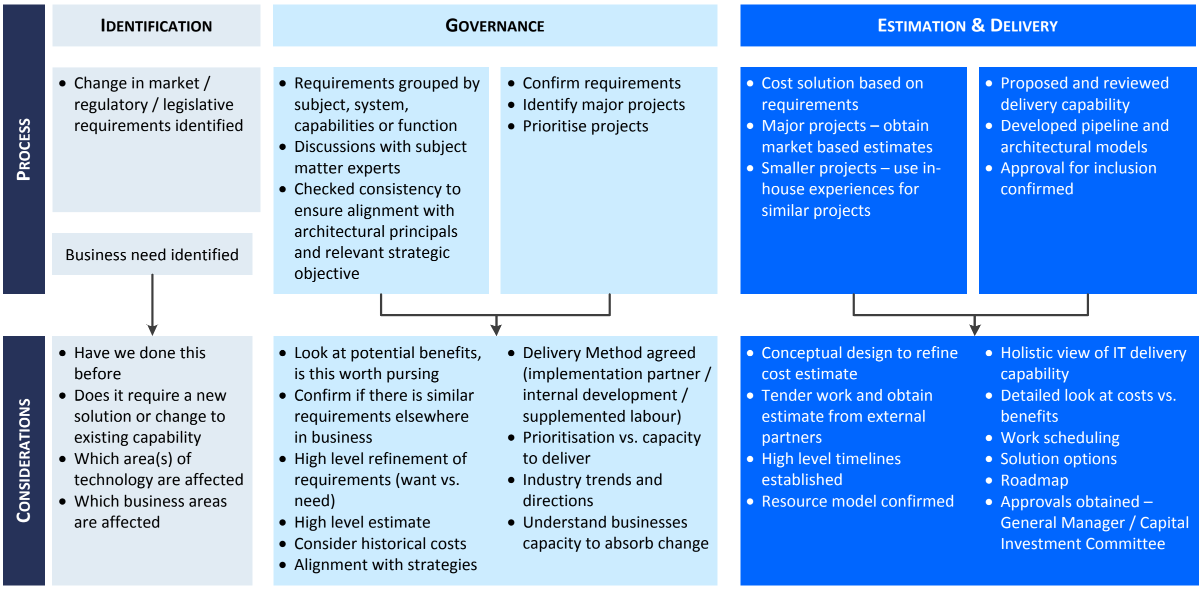
This section describes Powercor's methodology for forecasting IT and communications capital expenditure.

7.2.1 Forecast methodology

The methodology used to forecast expenditure required for the 2016–2020 regulatory control period is consistent with the methodology and processes that Powercor uses for the costing and estimation of all IT projects.

This three phase approach of identification, governance, and estimation and delivery are outlined in figure 7.2.

Figure 7.2 Project initiation process and considerations



Source: Powercor

Powercor has identified the business needs for the IT and communications program through an iterative process which has involved:

- identifying hardware and software replacement cycles and assessing the most prudent method of maintaining currency;
- anticipating future business needs through analysis of IT and energy industry trends, as well as considerations of Powercor IT strategy and direction;
- understanding current and future market, regulatory and legislative changes, as well as the implications for the IT systems; and
- consideration of varying internal and external support models, cloud and purchase models.

[114] Colmar Brunton Research, Powercor stakeholder engagement research report – residential customer focus groups & SME customer interviews, 30 April 2014, p. 34.

The rapid changes in the IT and communications landscape require a continual review and reworking of the business plans and proposed solutions. Powercor must ensure that for each business need that the impacts on systems and processes are clearly understood, which may lead to refinement of the potential solutions.

Powercor's governance processes include consideration of cost estimates for different solutions and delivery options for each business need. The original requirement and preferred solution is then reviewed to re-confirm the required scope, and to determine whether there are other similar requirements sought by the business where delivery synergies can be achieved. The requirements and the delivery options are also checked for alignment with Powercor's overarching strategic direction, as well as IT strategies.

Finally, robust cost estimates for each requirement are prepared, which have been sourced from:

- market based outcomes from competitive tender processes–costs reflect the rates contained within Powercor's contracts with the successful tenderers for the device replacement stream and labour rates following the establishment of contractor and consulting panels;
- estimated data obtained from contractors or vendors–robust cost estimates have been obtained for large projects including the CRM, billing replacement and RIN projects, the smarter networks and security streams;
- actual historical costs for similar projects–this process has been used for many of the smaller currency stream projects; and
- historical tender processes or similar projects-this process was used for some infrastructure-related projects.

Where the cost estimates are based on historical costs for similar projects, those costs are reflective of any competitive tendering processes to source materials, contract labour and services, and risks and uncertainty that were borne in undertaking the projects.

The timeline for the delivery of each business need is considered together with other requirements. Powercor has flexible resourcing arrangements so that the program of work can be delivered and implemented to meet the timeframes.

Each IT and communications system change has been evaluated by Powercor to ensure it meets the identified need, is prudent, efficient, and can be implemented in the required timeframe.

7.2.2 Key drivers of expenditure

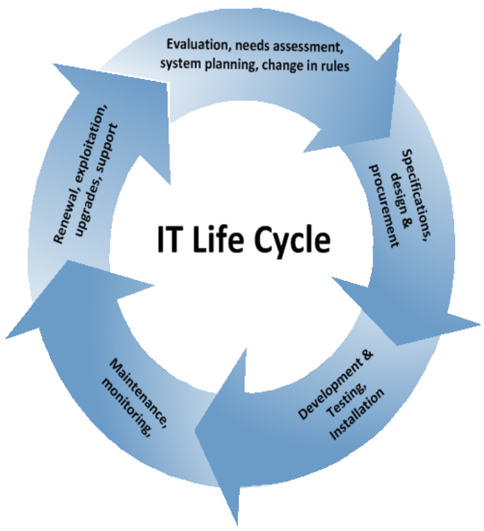
Key drivers of IT and communications expenditure are the IT lifecycle and replacement, upgrades and maintenance of existing systems to ensure that they remain up-to-date. In addition, Powercor may be required to introduce new systems or functionality to meet industry or regulatory requirements. These matters are discussed below.

IT lifecycle

IT expenditure is cyclical for each system: expenditure peaks following the purchase and implementation of a new system, and then falls as the system is maintained and upgraded over time. As the system approaches its end-of-life the expenditure increases again as patches and fixes are made to prolong the life before it is ultimately replaced.

Powercor's lifecycle management objective has been to meet the business need in a timely and efficient manner, reusing technology where technically possible and introducing proven technologies and taking opportunity to realise generational technology improvement when appropriate. The length of IT lifecycle varies for every IT system and for every company that uses that system.

Figure 7.3 The IT lifecycle



Source: Powercor

Powercor follows the approach of investing in major applications then operating and modifying them to meet changed requirements for as long as possible.

Triggers for reimplementation are a blend of:

- fundamental change in business requirements often due to regulatory or market changes;
- step changes in underlying technology rendering application unsupportable;
- shifts in the environment in which the business must operate which require fundamental changes to the IT architecture (e.g. operation and support of AMI network);
- adoption of new technologies to support underlying business effectiveness (e.g. mobility); and
- increases in the scale of operation such that the legacy applications and technologies are no longer adequate to support business operations at the required level of service or transaction volume.

During the 2016-2020 regulatory control period there will be an intersection of a number of these triggers:

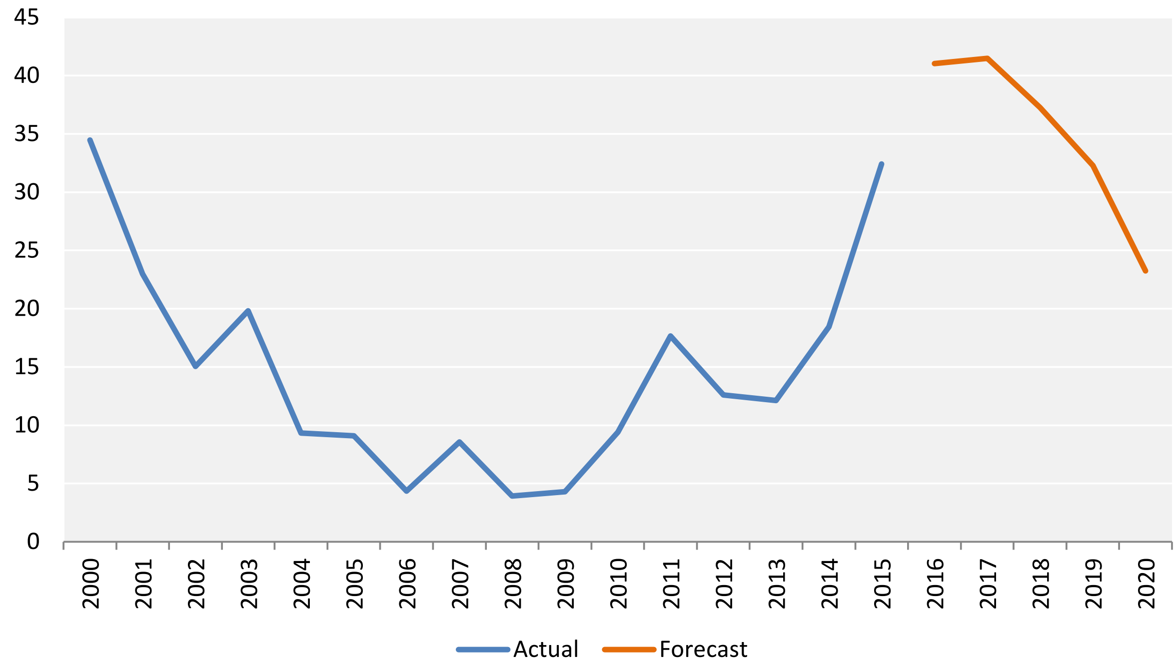
- regulatory change-changes in business requirements following the AEMC's Power of Choice review, the proposed introduction of metering competition, and the Australian Energy Regulator's (**AER**) reporting for Regulatory Information Notices (**RIN**);
- support of new and innovative business operations imperatives and technology-continued movement towards a smarter network;
- expansion of mobility devices and applications and integration into IT and communications systems to support business effectiveness and customer expectations;
- generational change in a number of technical architectures that support underlying architectural building blocks;
- increased usage and storage of multiple data types for reporting and operational management e.g. metering events, Lidar and network control point monitoring; and
- fundamental changes in the requirements for the security of the network and its communications systems with heightened external threats compared to the current regulatory control period.

The combination of these events is reflected in the cyclical upswing in required IT expenditure in 2015-2017 followed by a period of consolidation from 2018 to 2020.

Powercor's overall expenditure profile for IT follows this lifecycle pattern, as shown in figure 7.2. Two of the larger systems in the IT landscape are the SAP enterprise software, which manages business operations, and the Customer Information System – Open Vision (**CIS-OV**) billing system, both of which were implemented in around 1999/ 000. In the 2000-2008 period, Powercor's focus was on small enhancements to these relatively new existing systems.

Also, from 2006 to 2013 the standard control systems were maintained and enhanced due to the focus on the implementation of smart meter related systems (not included in the analysis below). In 2014 and 2015, Powercor has re-commenced its investment in these standard control systems.

Figure 7.4 IT non-network capital expenditure ($ million, 2015)



Source: Powercor

Recurrent vs non recurrent spend

Powercor has applied a consistent methodology to distinguish between recurrent and non-recurrent expenditure, based upon the methodology set out in the Category Analysis RIN. In particular:

- recurrent expenditure relates to replacement, upgrades and maintenance of existing functionality and systems in the Powercor IT landscape. For example, this includes replacement of the billing system, device replacement, and upgrades, expansion and refresh of infrastructure; and
- non-recurrent expenditure relates to new functionality or new (not replacement) systems that will be introduced to the Powercor IT landscape. For example, this includes the Customer Relationship Management system (**CRM**), the new RIN reporting requirements and SSL Decryption software incorporated into the security stream.

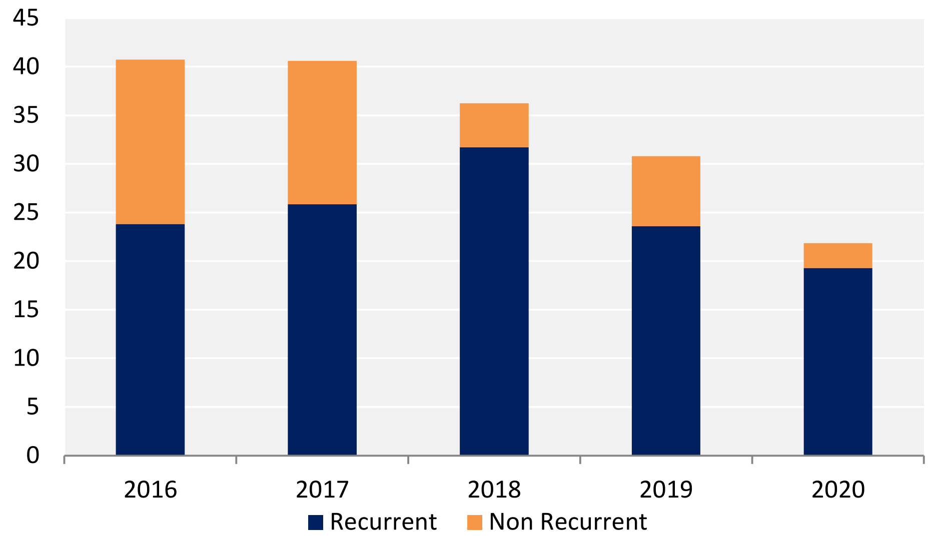
This approach to the recurrent/non recurrent split is reflective of Powercor's approach to:

- investing in new technology where appropriate then managing the effective life of that investment through fit-for-purpose enhancement and modification;

- recognition of the importance of solid strategic investment in core IT systems that can be efficiently enhanced; and
- the increasing scope of IT systems supporting the business and the refresh requirements across that base.

Powercor has identified whether the expenditure contained in each project or program of work is recurrent or non-recurrent expenditure. Overall, its expenditure is forecast to be 75 per cent recurrent and 25 per cent non-recurrent over the 2016–2020 regulatory control period, although it varies year-to-year within that period as shown in figure 7.5.

Figure 7.5 Recurrent / non-recurrent split per year ($ million, 2015)



Source: Powercor

This high level of recurrent expenditure is reflective of Powercor's position within the IT lifecycle where many existing systems are in the maintain and run stages of their lifecycle, than in the replace phase. The breakdown of the recurrent and non-recurrent IT and communications expenditure into the various streams is shown in table &.1.

Table 7.1 IT recurrent and non-recurrent spend by stream

Stream	% recurrent	% non-recurrent
Compliance	21	79
Currency	100	0
Customer engagement	52	48
Security	74	26
Smarter network	81	19
Infrastructure	100	0

Device replacement	100	0

Source: Powercor

The relative investment in IT streams reflects both the relative nature of their investment profiles and cycles. The currency stream is essentially to maintain the current state so therefore has no non-recurrent expenditure whereas customer expectation has driven a relatively high level of new requirements (or non-recurrent spend) in customer engagement. The high non-recurrent expenditure in compliance reflects the range of new requirements expected in this stream. Both the security and smarter networks streams reflect the continued investment in current systems and introduction of new and innovative solutions.

7.2.3 Deliverability

The service delivery pipeline for IT programs takes into account the prioritisation of works, together with the capacity and capability of Powercor's systems and resources.

IT resource planning draws on the IT governance works program to identify the specific resources and skills required to deliver individual projects and programs of work. This program profile is used to develop a program plan that ensures the delivery of projects and programs within specified timeframes in the most efficient and cost effective manner.

The delivery approach is determined by the IT capital portfolio governance group, taking into account resource availability, required skill sets, delivery timeframe and project requirements. Options for delivery are:

- internal delivery-internal employees manage and deliver the project;
- supplemented business labour-a blend of internal employees and labour hire staff drawn from a panel of preferred supplier contractor companies, manage and deliver the project; or
- implementation partner-drawn from a competitive tender process with a panel of preferred suppliers, the implementation partner manages and delivers the project, using internal employees where necessary.

Establishment of the proportion of delivery to be performed internally and externally has taken into account:

- skill and labour flexibility;
- variability in the timing and extent of skill demand;
- retention of core intellectual property within the business;
- access to leading edge delivery capabilities and implementation approaches;
- ability to leverage like projects delivered previously by external providers; and
- supply availability of the various labour classes.

Powercor has determined the number of work hours required to deliver the IT capital program is forecast to maintain its 2015 service delivery level in the 2016–2020 regulatory control period.

Each project or program of work has been estimated using market based outcomes from competitive tender processes; historical tender processes or similar projects; estimated data obtained from contractors or vendors; or actual historical costs for similar projects. The estimated hours to deliver from all the IT projects have been combined to produce a yearly forecast. This forecast is set out in table 7.2 below.

Table 7.2 IT work hour requirements

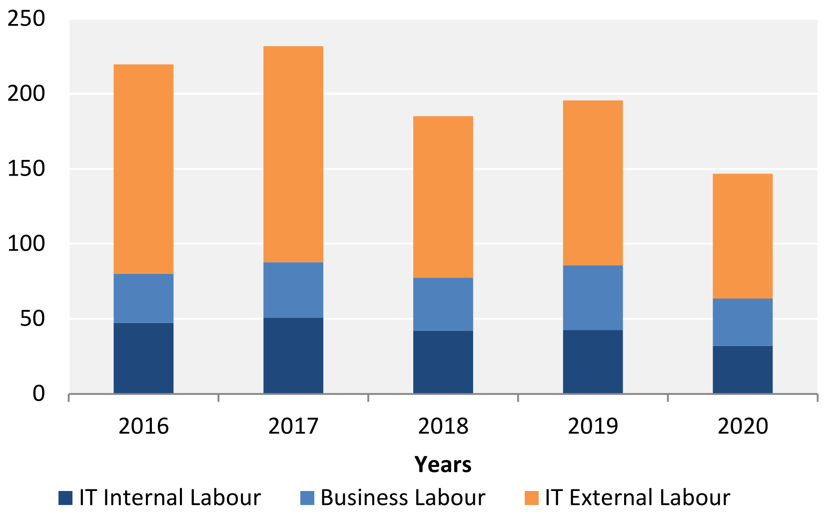
	2016	2017	2018	2019	2020
Total work hours	219,676	231,818	185,109	195,497	146,774

Source: Powercor

The largest program for delivery over the 2016–2020 regulatory control period is the implementation of the new billing system, scheduled in 2016 and 2017. The timing is dictated by the rule changes following the Power of Choice review. Given constraints in terms of internal labour resources, Powercor will need to draw upon its flexible labour resources using supplemented business labour and implementation partners to deliver this program.

The breakdown of the resource allocation is split between IT internal labour, business labour (non-IT) and external labour as seen in figure 7.6.

Figure 7.6 Deliverability – IT and communications capital program



Source: Powercor

7.3 Historical expenditure

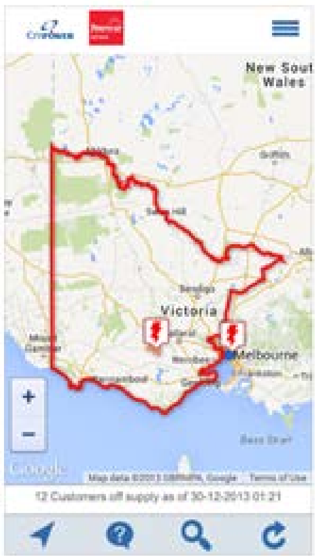
The seven work streams proposed in the 2016-2020 regulatory proposal are reflective of Powercor's areas of investment during the current 2011-2015 regulatory control period. Powercor has successfully delivered a range of initiatives during this time, many of which provide the foundation for further investment and innovation going forward.

Powercor has delivered the following initiatives within the IT and communications streams:

- **currency—**the ever changing nature of IT means that an ongoing investment is required to keep systems, software and infrastructure current. In the 2011–2015 regulatory control period Powercor has undertaken an extensive currency program. Powercor has chosen to invest in proven, reliable and industry leading software and application solutions, upgrading, enhancing and modifying to meet changing business and industry needs as an alternative to re-implementing and changing software to attempt to meet these needs. Currency has included upgrades to many systems including the billing, treasury management, fleet management, service suite, telephony and Oracle 12c systems, as well as mapping the low voltage network into the GIS and improving its website capability;

- **customer engagement—**the historical spend associated with customer engagement is reflective of Powercor's ongoing commitment to better engage and service its customers. This has included the introduction of the REConnect application to streamline connection applications, and other improvements to engagement with customers including a claims management tool and changes to push communications for all account types;
- **security—**the review of the security and vulnerabilities has been a growing process over the last five years. This process has been influenced by the introduction of smart meters and the constant increase of threats and the sophistication of those threats against its systems. To keep pace with these evolving threats Powercor has continued to initiate projects to increase its security posture and rectify any concerns to further protect its IT systems and infrastructure during 2011–2015 regulatory control period these include implementation of new firewalls to prevent intrusions into the web applications, corporate and SCADA systems together with implementation of a new security information event management solution to improve IT security incident and response capabilities;
- **mobility and device replacement—**during the 2011–2015 regulatory control period Powercor has maintained and continued to grow its personal computing (**PC**), printer and workstations fleets and substantially expanded its mobile computing capabilities. The introduction of the smart phone and tablets has fundamentally changed Powercor's operating model. Initially thought of as a nice-to-have 'fancy telephone' these smart devices allow access to real time data, anywhere. The following development, design and implementation initiatives were enabled by the use of smart devices: network fault and outages apps which provide geospatial visualisation of unplanned outages to employees and customers, 'Never Compromise' health and safety app that allows field reporting of hazards and incidents, and a field work issue app that supports the field deployment of armour rods and vibration dampers;
- **infrastructure—**Powercor's historical spend for its infrastructure program is cyclical in nature and the 2011–2015 spend profile is reflective of this pattern. Examples of projects undertaken for infrastructure include: increases in capacity and technical refresh for a range of servers, storage, data protection, routers and network infrastructure, including the network core switch infrastructure; migration from physical to virtual servers for Microsoft Exchange and migration to new data protection infrastructure;
- **compliance—**Powercor has many and varying regulations, laws, guidelines and specifications that must be adhered to within its business. Many of these rules and regulation changes have a direct impact to its IT systems. Functional and process changes are required to meet changing needs. During the 2011–2015 regulatory control period Powercor addressed a number of compliance changes, including: annual updates to business to business (**B2B**) systems to meet AEMO requirements, as well as changes to the superannuation,

The CitiPower and Powercor 'outages' app provides details on unplanned outages to customers



Source: Powercor

payroll and the incident management system to achieve compliance; and

- **smarter network—**Powercor has also continued to invest in significant programs to build upon the functionalities of the AMI smart meters to move towards a smarter network. Powercor has delivered network management system (**DMS**) which provides real time network schematics for improved operational switching, patching and network utilisation, switching register application to manage planned works. In addition the following programs were undertaken in the 2011–2015 regulatory control period as discussed below.

Table 7.3 Completed smarter networks initiatives

Initiative	Brief Description
Meter Outage Notification (MON)	Use outage data provided by the AMI meters in an intelligent process to generate meaningful notifications to systems that are used to coordinate response to the outages
Distribution Transformer Monitoring	Access to Distribution Transformer interval data and customer interval data linked to a specific asset to support asset management and protection against theft
Power Flow Analysis	Migration of power flow data from multiple sources into the DMS to allow for distribution network modelling based on realtime SCADA values
Proactive Voltage Monitoring	Voltage polling tool used by the network quality team to investigate Voltage anomalies remotely. Avoided cost associated to operational impact of solar installations
AMI Safety Reporting	Utilise AMI data to identify safety concerns in the network. Improved safety outcomes for customers and staff
Home area networks / in home displays	Trial in approximately 1,000 homes installing in-home display units bound to CitiPower's AMI smart meters via the establishment of an authorised Home Area Network (HAN).

Source: Capgemini, *Networks for the future – ICT roadmap*, December 2014, pp. 18-19.

Impact of AMI

During the 2011-2015 regulatory control period Powercor has been committed to the full development, implementation and operational support of IT systems to enable the smart meter deployment program, which has required a re-balancing of resources between AMI and SCS business activities.

While Powercor has delivered many successful initiatives, overall it has underspent the AER's IT and communications SCS allowance by 27 per cent.

As noted in the ESC Compliance with AMI Regulatory Obligations report Powercor achieved 94 per cent of its overall AMI rollout target, and had visited 99 per cent of prescribed customer sites to try and install an AMI meter[115]. In addition to this the audit confirmed that the technology selected and installed by Powercor met 100 per cent of the requirements of the Minimum AMI Functionality

[115] ESC, *Compliance with AMI Regulatory Obligations as at 31 December 2013*, October 2014, p. 14

Specification and that Powercor met all three performance standards for remote reading of AMI meter data, and could remotely connect and disconnect a customer's electricity supply.

The system implementation to support the smart meter program consisted of two components:

- the development and implementation of systems to support the deployment and commissioning of smart meters; and
- the development and implementation of systems to communicate with the deployed meters, collect meter readings, enhanced billing and dispute management process, enhance network management process to cope with interval meter volumes, distribute the meter data to market, respond to market transactions and automate previously manual functions such as de-energisation.

The deployment of smart meters involved the creation of a rollout specific Works Management System (**WMS**). The WMS automated the scheduling and allocation of jobs to the field mobility devices allowed field personnel to install smart meters. The closure of each job was notified back through WMS to CIS-OV via the integration layer. Any exceptions were handled within a customised workbench that allowed dedicated scheduling staff to expedite the resolution of issues and complete the smart meter installation.

Other components of the deployment phase included development of customer portals to support scheduling of installation appointments, enhancements to logistics systems, enhancements to support market conversion of meters from manually to remotely read.

The second component of the program, which supports the ongoing operation of the metering required the introduction of key systems such as:

- UtilityIQ to capture smart meter data, which ultimately replaced the multi-vendor remote station (**MVRS**) and multi-vendor interval data processing (**MV90**) systems which had been used to capture data from the old hand-held devices used by manual meter readers for the old type 5 and type 6 meters; and
- Itron Enterprise Edition (**IEE**), which replaced the existing MDM and NTMS systems. This application required significant enhancement to support Australian Market rules and AMI specified service levels, as well as the complex billing aggregation requirements of interval meters.

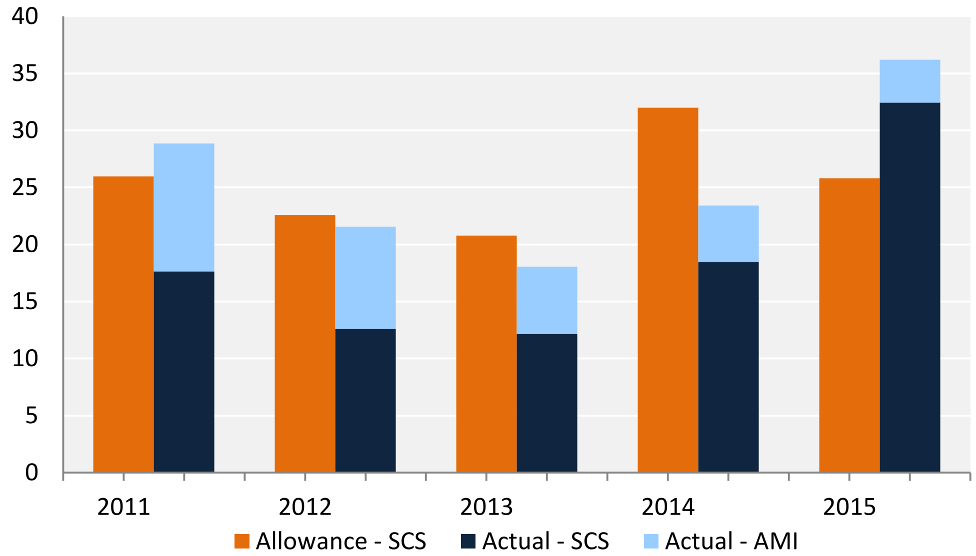
In addition to the deployment of key systems, significant investment was required to the billing and reporting environments to operate in an interval meter environment, along with integration effort to incorporate these systems into the overall IT architecture.

The vast data volumes increases associated with smart meter operation, coupled with the tight service level obligations for delivery of data to the market and retailers necessitated investment in scalable storage and processing infrastructure architectures well in excess of what was required to support an accumulation meter environment.

These systems and infrastructure will require continued investment to support their ongoing operation following the expiry of the specific regulatory instrument, and forms part of Powercor's standard control submission for this period. UIQ and its associated infrastructure and security will remain as part of metering expenditure.

The scale of the AMI program and its impact of Powercor's overall IT deliverables for the 2011-2015 regulatory control period is seen in figure 7.7.

Figure 7.7 Expenditure 2011-2015 IT (dollars million, 2015)



Source: Powercor

7.4 Forecast expenditure

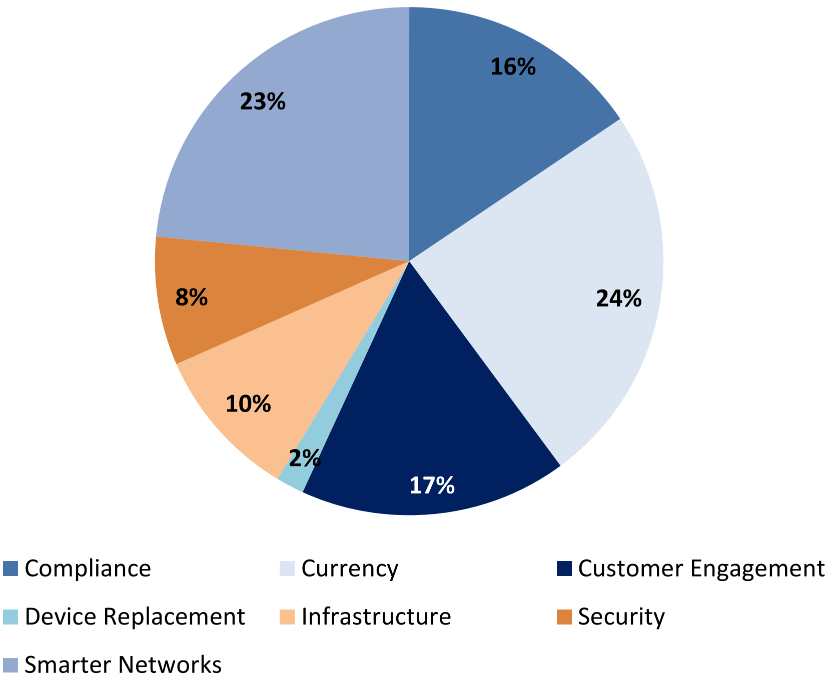
For the 2016–2020 regulatory control period, Powercor requires an 88 per cent increase in IT and communications expenditure investment compared to the 2011-2015 standard control services (**SCS**) allowance. This investment will enable Powercor to efficiently maintain its industry recognised high level of service delivery to all stakeholders and will ensure that prudent investment is made in innovative solutions to meet the ever evolving customer need.

The expenditure forecast is underpinned by the following program of work where Powercor needs to:

- manage upgrade and refresh lifecycles of core IT systems, applications and hardware;
- mitigate the evolving sophistication of security risks to the IT and communications networks;
- ensure market, regulatory and legal compliance, particularly the AER's existing, new and proposed RIN reporting requirements (which provide valuable information that allows the AER to measure Powercor's high level of service delivery and efficiency) and facilitate Power of Choice for its customers; and
- continue to build upon the strong foundation that delivers a network of the future and empowers customer choice.

Powercor has allocated each project into streams which align with the service delivery categories in the IT strategic plan, and which represent the top technological priorities of the business.

Figure 7.8 Forecast expenditure by IT investments stream



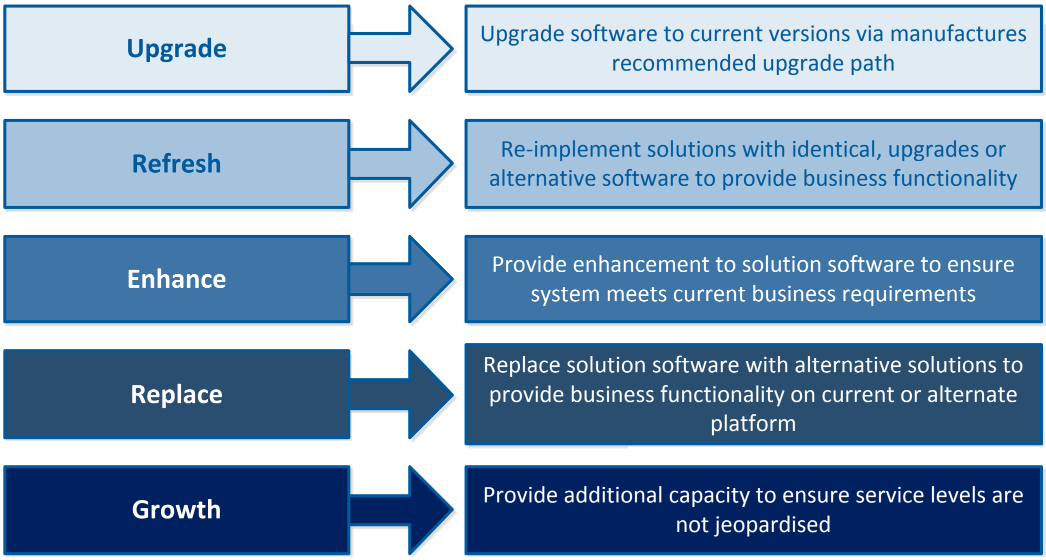
Source: Powercor

The expenditure in each investment stream is discussed below.

7.4.1 Currency

Powercor has over 50 systems and applications that it needs to maintain to support the operations of the business. Each of the systems must be maintained, upgraded and/or refreshed to ensure that the system remains current and able to perform its required functions. This is shown in figure 7.9.

Figure 7.9 System lifecycle considerations that influence currency investment



Source: Powercor

In addition, IT software must be enhanced to meet new or changed business requirements, or replaced where it is no longer a suitable solution. Increases in data volumes or transactions can also result in the need to increase the processing capacity of the systems, and are influenced by a number of considerations, including:

- resource utilisation-monitoring, analysing, tuning, and implementing necessary changes in resource utilisation;
- demand management-managing demand for computing resources in line with business priorities;
- system performance-modelling to simulate infrastructure performance and understand future resource needs;
- application sizing-application sizing to ensure required service levels can be met; and
- storage capacity-ensuring storage capacity is adequate to meet immediate and future needs.

Many of the key operational systems are supported by a third party vendor, these must be regularly upgraded and/or refreshed to ensure that the vendor support and maintenance contract remains valid. This includes maintaining the installed version within the acceptable range allowed by the vendor and that adequate capacity and functionality is provided to meet current and future business requirements.

Powercor has reviewed its suite of IT and communications systems to forecast the expenditure required to maintain the range of existing systems, including:

- Oracle Fusion Utility Service Bus (**USB**) which is a system integration and business process orchestration;
- SAP which covers a range of functions including asset management, works management, materials and logistics, human resources and finance;
- PowerOn Fusion which undertakes outage management, SCADA management and other functions; and
- IEE, MTS and other systems.

Maintaining the currency of these systems is imperative to allow Powercor to continue to provide fully supported systems that underpin the operation of the network.

7.4.2 Smarter networks

Powercor continues to build upon the foundations provided by the deployment of smart meters by utilising their enhanced capabilities and functionality. The smarter grid transformation is a long journey from the traditional (analogue world) to a smart grid (an intelligent and responsive network) where information and data flows enable service providers to support the choices that customers make, per figure 7.10.

Figure 7.10 Smart grid transformation

	Traditional Grid	Smart Grid
Communications	One-way, delayed	Two-way, real-time
Customer interaction	Limited	Extensive
Metering	Electromechanical	Digital
Operation	Manual equipment checks maintenance	Remote monitoring, predictive, time-based maintenance
Generation	Centralised	Centralised and distributed
Power flow control	Limited	Comprehensive, automated
Reliability	Prone to failures and cascading outages; essentially reactive	Automated, proactive protection; prevents outages before they start
Restoration	Manual	Self-healing
System Topology	Radial; generally one-way power flow	Network; multiple power flow pathways

Source: Capgemini, *Networks for the future – ICT roadmap*, December 2014, p. 18.

During the 2016–2020 regulatory control period, Powercor will continue to move towards a 'network of the future'. The smarter grid will change the way that Powercor generates data, presents information, makes decisions, executes work and relates to customers. Customers will also benefit from improved quality of electricity supply, and better information and options for how they interact and utilise the network.

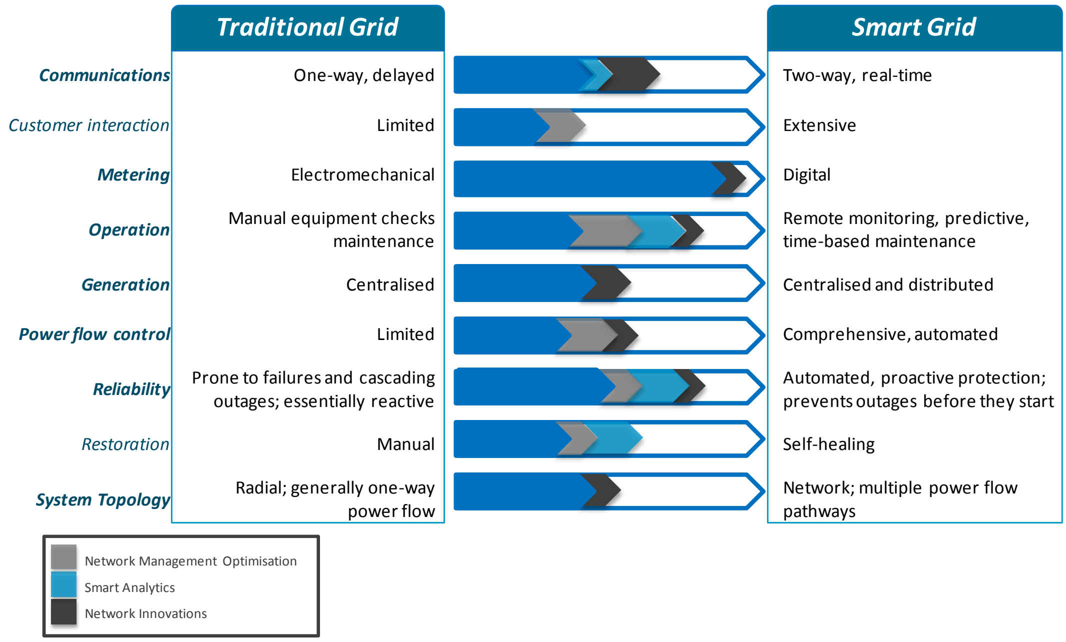
Capgemini has prepared a roadmap for Powercor to continue on its journey towards a smarter grid. The roadmap sets out the required investment to enable improved network management and delivery of new services to customers, comprising three key initiatives:[116]

- **network management optimisation**-the aim of this initiative is to optimise the current multiple existing Information Technology/Operational Technology (**IT/OT**) systems that need to be integrated into the smart grid solution. This initiative will deliver efficiencies and benefits by converging business resources, processes and IT systems across the network;
- **smart analytics**-this initiative is focused on managing the 'explosion of data', which is a consequence of the smart meter implementation. In order to make the grid smarter, this stream will undertake a number of programs to collect, process, store and exploit this data; and
- **network innovation**-the network innovation initiative is focused in the technology innovation that can help deliver benefits to consumers by enhancing efficiency in network operations.

These investments will progress Powercor along the path to a smarter grid, as shown in figure 7.11.

116 Capgemini, *Networks for the future – ICT roadmap*, December 2014, pp. 5-6.

Figure 7.11 Capabilities delivered through investment in a smarter grid



Source: Capgemini, *Networks for the future – ICT roadmap*, December 2014, p. 30.

Customers have strongly supported Powercor's transition to a smarter grid through the stakeholder engagement program. The above investment will assist in meeting customer expectations for better network management and optimisation, as well as facilitating greater opportunities for customer interaction and control.

7.4.3 Customer engagement

The customer engagement stream incorporates Powercor's response to ongoing changes and demands from its customers for greater access and greater choice in electricity services.

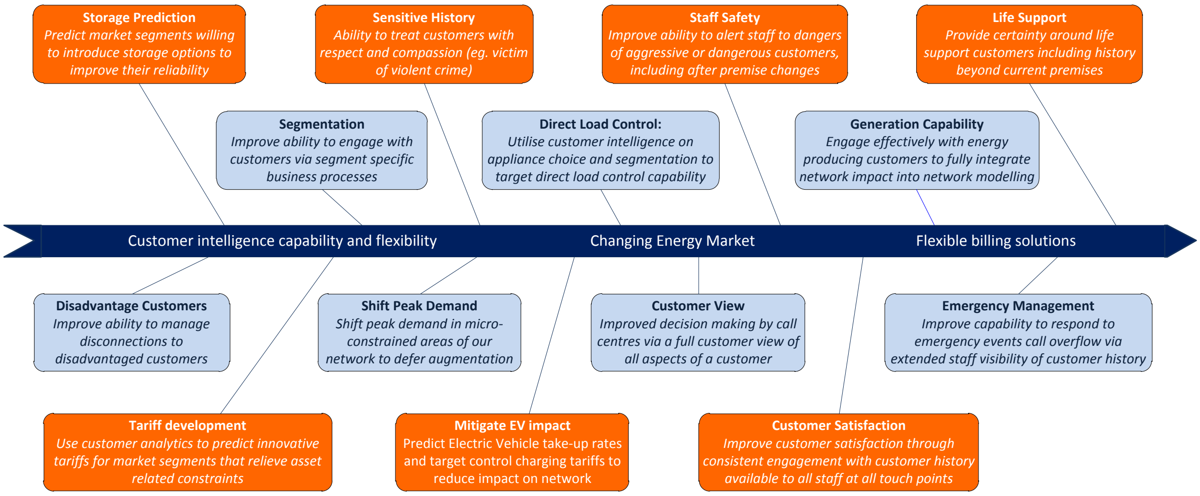
Market forces are shifting the traditional linear energy supply chain to a contemporary model where consumers become producers (i.e. prosumers) and distributors become enablers of energy solutions. In response to these industry forces, energy market and industry changes are being progressed by regulators to increase innovative participation by customers in the market.

To meet the changing need of its customer, and to comply with the regulatory changes including those associated with the AEMC's Power of Choice review, Powercor needs to be able to meet the following requirements:

- to respond effectively to the changing energy market, a customer intelligence capability is required to more effectively engage and influence customer behaviour;
- to respond to the changing market, the capability to implement flexible, innovative and dynamic tariffs requires a modern billing system that can evolve with the industry;
- to enable customer access to energy data and encourage informed consumer choice and participation, to develop a suite of customer enablement capabilities; and
- to address the challenges of the increasing complexity of customer interactions as the market evolves, driving the need to move from National Mater Identified (**NMI**) centric engagement to multi-faceted customer and provider view.

Figure 7.12 depicts the factors that are driving the changes in the energy market, and how Powercor will meet those changes.

Figure 7.12 The changing energy market



Source: Powercor

The current billing system cannot meet emerging market requirements and will require significant modification on a high risk outdated platform. Deloitte Access Economics noted that: [117]

> *…anticipated industry and regulatory change and expected to have significant implications for billing and customer management functions.*

Powercor will implement a new Customer Relationship Management (**CRM**) capability and flexible billing system through a program of work that will replace the current CIS-OV billing system and provide customers greater access to their energy information allowing them to make informed choices. This is required to manage the increasing complexity of the direct customer relationship and emerging customer billing requirements.[118] It will also involve system integration, reporting capability and data migration.

Powercor engaged Capgemini to undertake a scan of the CRM and billing systems in the market that would meet its internal customer requirements, as well as the anticipated future regulatory and market changes. Capgemini recommended SAP ISU billing system together with a cloud-based CRM managed by Salesforce [119] as a sound basis to meet these requirements.

In addition, Deloitte Access Economics (**DAE**) has identified and calculated the benefits to customers of a new billing and CRM system and compared it to the Capgemini costs. Customers will benefit from the investment in a new system as a result of:

- the ability for us to implement new tariff options that help lower peak demand and thus reducing network investment;
- costs that Powercor would avoid from upgrading the existing system; and

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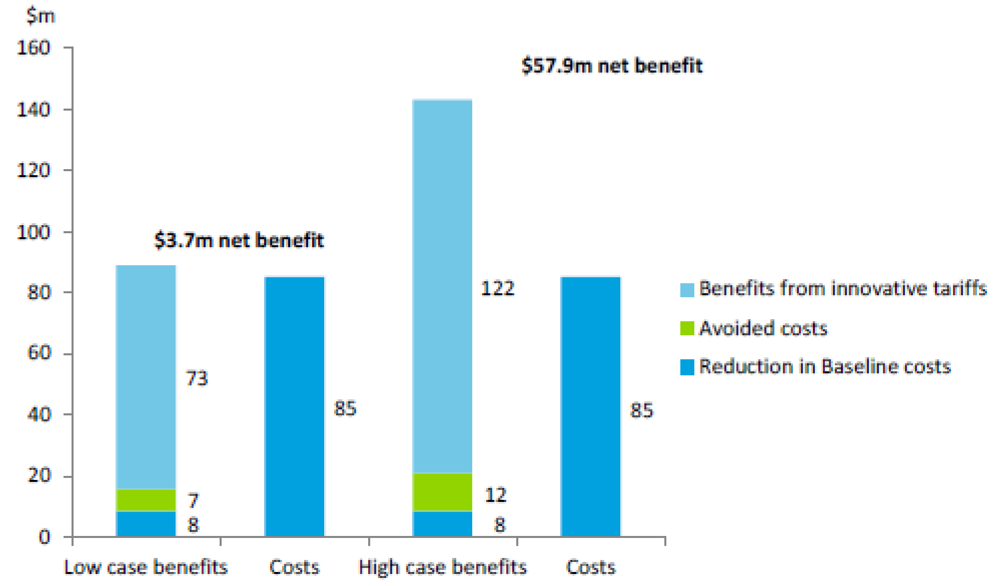
117 Deloitte Access Economics, *CitiPower and Powercor- Investing in a new billing and customer relationship management system*, December 2014, p. 10.

118 CitiPower and Powercor, *Business case – CRM and billing system replacement*, February 2015.

119 Capgemini, CRM and Billing Market Scan – Final Report, 27 June 2014.

- reducing the costs to operate the existing system.

Figure 7.13 Net economic from investing in a new CRM and billing system



Source: DAE, *Investing in a new billing and customer relationship management system*, 16 December 2014, p. 4.

Overall, DAE found the there is a net benefit to customers of between $3.7 million and $57.9 million if CitiPower and Powercor invest in a new CRM and billing system.

Take-up of innovative tariff offers

In September 2014, Nature undertook a survey of 804 Powercor customers to understand the take-up of innovative tariff offers, namely:

- peak time rebates; and
- direct load control on air-conditioners or pool pumps.

Powercor would be able to take advantage of the deployment of smart meters to implement these innovative tariff offers, which would deliver benefits by reducing consumption of electricity at peak periods — thus reducing peak network demand and consequently the need for network investment.

The survey response for peak time rebates was very positive, with 60 per cent of Powercor customers willing to make genuine sacrifices to their comfort and reduce their energy usage for two hours per day when the temperature is over 38 degrees, in return for a cash rebate.

Turning off the air-conditioner was the second most preferred option to save energy to obtain the cash rebate.

For those customers with either a non-evaporative air-conditioner or a pool pump, then 36 per cent of customers surveyed were willing to receive a rebate in return for Powercor remotely controlling the equipment, i.e. direct load control. This would involve Powercor installing a controlling device in the equipment which would allow it to remotely control the air-conditioner or pool pump on the hottest seven days of the year when the temperature is over 38 degrees.[120]

For air-conditioners, Powercor proposed turning the air-conditioner to ‘fan-only’ mode for five minutes every 15 minutes, for a period of two hours. For pool pumps, Powercor proposed remotely switching off the pool pump for a two hour period.

Of all customers surveyed with either air-conditioning or pool pumps, then:[121]

- 31 per cent of customers with only air-conditioning were willing to sign-up for direct load control;
- 72 per of customers with only pool pumps were willing to sign-up for direct load control; and
- 31 per cent of customers with air-conditioning and pool pumps were willing to sign-up for direct load control.

Powercor requires a new billing and customer relationship management system to implement these innovative tariff offers.

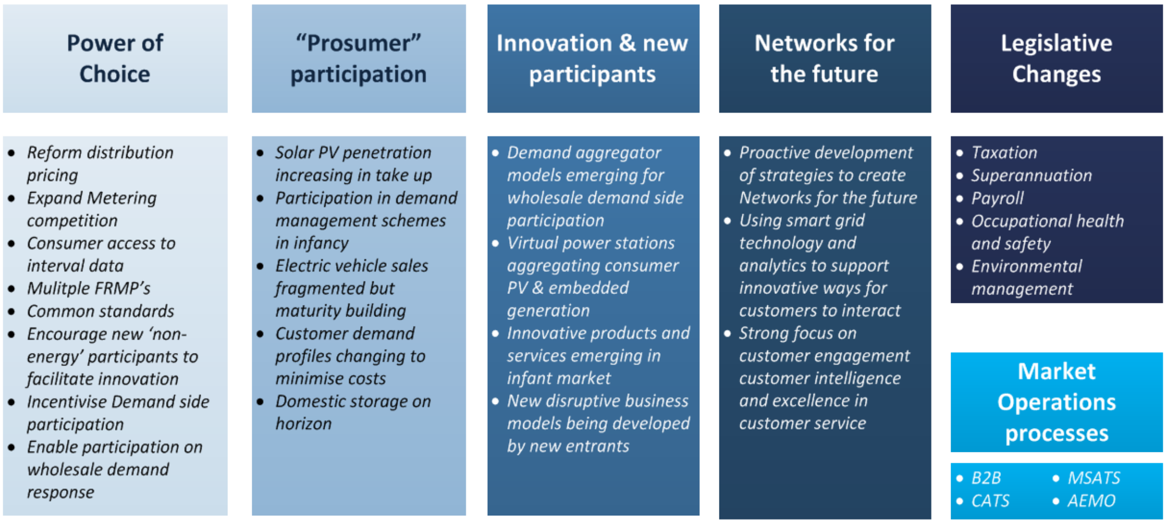
7.4.4 Compliance

The compliance stream relates to ensuring compliance with relevant financial, regulatory, statutory, and market obligations. The ability to meet compliance obligations is directly impacted by the capability of the systems, processes and analytics to deliver services and information when required by the relevant law or regulatory change.

120 Nature, CitiPower/ Powercor Tariff Research, 17 September 2014, p. 22. Appendix C within the report from Deloitte Access Economics, *CitiPower and Powercor- Investing in a new billing and customer relationship management system*, December 2014.

121 Nature, CitiPower/ Powercor Tariff Research, 17 September 2014, p. 22. Appendix C within the report from Deloitte Access Economics, *CitiPower and Powercor- Investing in a new billing and customer relationship management system*, December 2014.

Figure 7.14 Industry compliances influences



Source: Powercor

The stream involves meeting compliance obligations in a timely manner, taking into consideration development and implementation timelines for each of the obligations. The key drivers of the expenditure within this stream include:

- **financial compliance-**updates to the financial system, cost models and finance modules to ensure statutory compliance with taxation and accounting standards;
- **regulatory compliance-**updates to Powercor's systems to interact with AEMO market systems and other market participants, data capture and analytics to ensure compliance with regulatory reporting obligations and National Electricity Rule updated requirements;
- **statutory compliance-**changes to systems and processes to ensure compliance with all current and future legal obligations;
- **supporting system compliance**-updates to supporting systems such as occupational health and safety, human resources, payroll to ensure compliance with national, state and local obligations; and
- **regulatory information notice (RIN)-**preparation and maintenance of information for provision to the AER relating to all RINs. Fundamental system and business process changes are required to meet the AER requirement of providing actual information for the RINs, and to improve and automate the reporting of for all RINs.

In terms of meeting the RIN requirements, KPMG has recommended that Powercor implement an Activity Based Costing (**ABC**) approach to provide sufficient capability to deliver the reporting obligations for the Annual Reporting RIN, Fire factor RIN, Economic Benchmarking RIN and the Category Analysis RIN.[122]

KPMG noted that Powercor's existing systems and records have been developed to meet existing management, statutory accounting and regulatory requirements. The Category Analysis RIN and Economic Benchmarking RIN prescribe new and additional reporting requirements. To date, Powercor has achieved compliance by collecting information from outside of the existing systems and records and making estimates and judgements to classify information according to the RIN

[122] KPMG, *Business Case for expenditure to meet RIN requirements*, April 2015.

categories and definitions. However, as Powercor will not be able to report using 'estimated' data over the 2016–2020 regulatory control period, then the ABC approach will need to be implemented.

7.4.5 Infrastructure

Powercor seeks to prudently optimise asset lifecycles of physical infrastructure assets to ensure agreed service levels are maintained at the lowest lifecycle cost. The infrastructure steam relates to:

- provision of adequate capacity to meet forecast volume estimates (growth);
- refreshing infrastructure components to meet technical currency requirements (currency); and
- ongoing management and maintenance of the infrastructure to meet the required Service Level requirements.

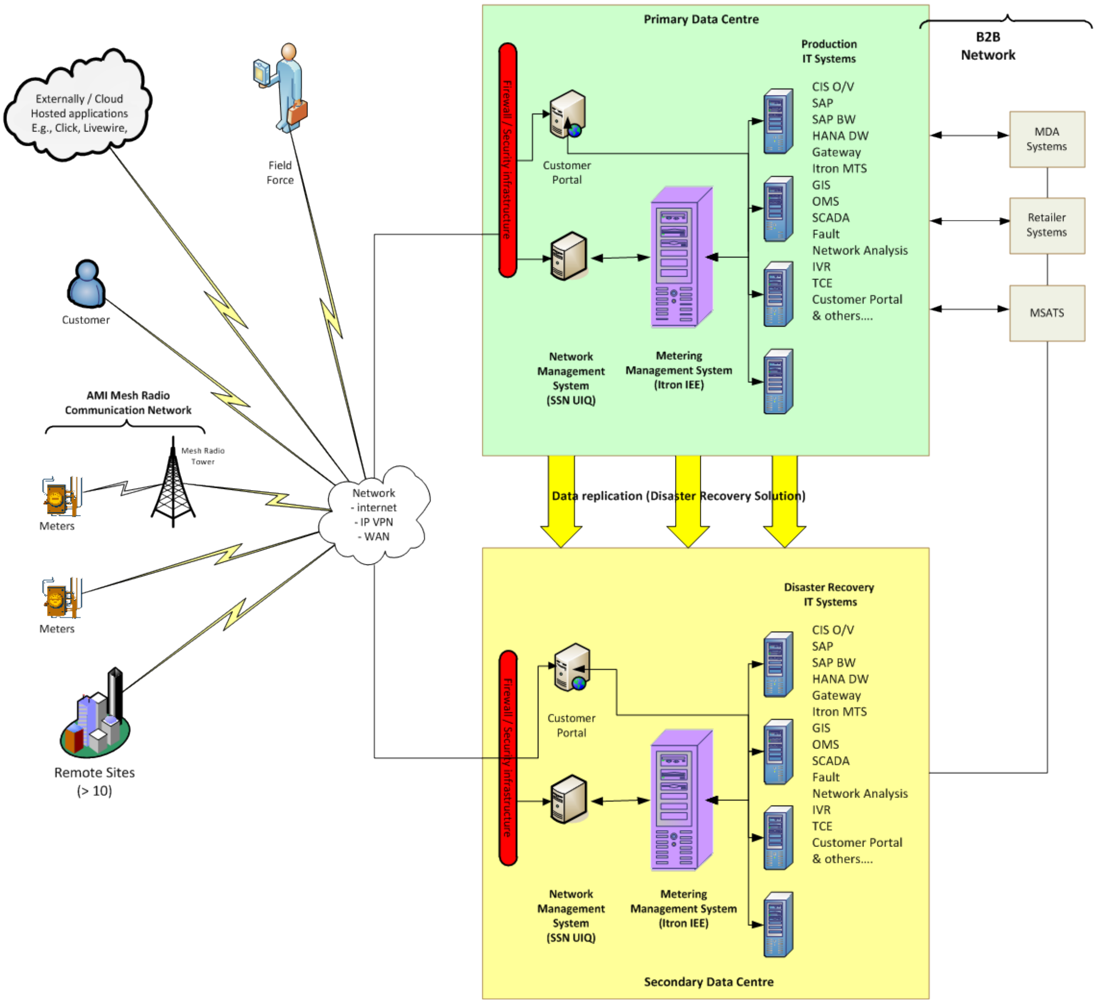
The infrastructure stream includes the following services:

- servers-SCADA and corporate servers including both Windows and UNIX servers, as well as hardware and associated server software;
- storage-Storage Area Network (**SAN**) and Exadata infrastructure, including switch, array and associated infrastructure. Capacity of the storage infrastructure is actively monitored to ensure ability to meet current and future requirements;
- data warehouse-including server and storage infrastructure that provides capability for operational reporting against large volume data;
- data centre infrastructure-primary and secondary data centres and associated equipment;
- Local and Wide Area Network infrastructure (**LAN/WAN**)-switch, router and associated equipment to support LAN and WAN infrastructure across the distribution area; and
- Backup-infrastructure to protect data against loss or corruption, including retention of aged backups to cater for historical data recovery.

A key element of the infrastructure expenditure is to meet requirements for disaster recovery at the primary data centre for core systems and communications in the event of equipment failure, intentional destruction or disaster at the secondary data centre, or vice versa.

Powercor's IT infrastructure has been designed to support existing and future applications and systems, which are accessed from multiple geographical locations, as shown in figure 7.15.

Figure 7.15 Powercor infrastructure landscape



Source: Powercor

The core drivers for the infrastructure stream is the increasing data storage requirement for the initial build of seven years of interval meter data history, business as usual capacity growth and technical currency refreshes and backup. In reviewing Powercor's infrastructure requirements, CSC noted that:[123]

> *A small number of meter data system related databases are responsible for 75% of storage growth.*

Powercor makes extensive use of virtual servers, with over 670 servers in the CitiPower and Powercor infrastructure landscape. Investment in virtualisation allows Powercor to make more effective use of its hardware resources, as well as offering rapid deployment capability, balancing of infrastructure workloads, simplified support models and enhanced availability.

Given the pace of technological advancements in infrastructure, Powercor needs to update, replace or refresh its infrastructure to ensure that it has sufficient capacity, computing power and memory to process the increasing quantity of data related to the network. In addition, Powercor needs to store relevant data and maintain a back-up for operational and regulatory reasons, and therefore

123 CSC, *Infrastructure requirements*, October 2014, p. 22.

will need to increase the storage and back-up infrastructure, including the data warehouse, to support the growth in data.

7.4.6 Security

Energy distribution is critical infrastructure that is at high risk of attack; prudent investment in security measures is deemed essential. To ensure that the availability of the distribution network is assured and that customers continue to receive a reliable distribution of controlled power, cyber-security threats need to be monitored, managed and mitigated.[124]

Powercor has undertaken significant investment within the security IT capability during the current regulatory period. This has enabled Powercor to install a secure network that manages over 810,000 smart meters as part of the AMI program. This program has resulted in an exponential growth in the number of internet capable devices that are connected to the existing IT network. The approach for the 2016-2020 security expenditure is to ensure that security of the network is maintained, proactively monitored and managed.

Over the 2016-2020 regulatory control period, Powercor seeks to ensure that the security of the network is maintained, proactively monitored and managed.

Powercor commissioned the auditing services of Ernst & Young to undertake an internal audit that examined the adequacy of key policies, procedures and processes governing the SCADA IT operations. Weaknesses in the security of the SCADA IT network were identified and an action plan established to address the findings.[125]

Subsequently, an additional audit was conducted by Ernst & Young, on behalf of Powercor, of the IT network. The audit objective was to evaluate the operating effectiveness of IT security to mitigate risks associated with an internal and external IT network attack and penetration, and develop recommendations to improve the internal controls environment. The audit report identified some critical and moderate findings that network security architecture and controls should be strengthened.[126]

Following these audits, Deloitte has, on behalf of Powercor, reviewed the security risks facing the network. The report highlighted that the risk of cyber-attacks on Industrial Control Systems (**ICS**) is increasing each year. The most recent figures indicate that the number of cyber-security incidents across critical infrastructure has doubled. More vulnerabilities that affect ICS/SCADA infrastructure are also being identified, therefore increasing the risk of cyber-attacks being successful[127].

In addition, adequate security of corporate systems is also necessary. Confidentiality of customer information is a primary security concern as personally identifiable information is now a primary target of cyber-attackers as they can use the information to establish credentials to perpetrate fraud, rather than directly stealing funds.

As a result, a program of IT security initiatives was developed, consisting of five work streams based on best practice which aim to extend and maintain today's IT security capability: identify, detect, monitor, protect and govern. These capabilities are shown in figure 7.16.

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[124] CitiPower and Powercor, *Information Security Business Case*, January 2015, p. 4.

[125] CitiPower and Powercor, *SCADA IT Operations Internal audit report*, September 2012.

[126] CitiPower and Powercor, *IT Security – Network Security Internal audit report*, July 2013. (confidential)

[127] CitiPower and Powercor, *Information Security Business Case*, January 2015, p. 4.

Figure 7.16 IT Security Capability Lifecycle

Source: CitiPower and Powercor, *Information Security Business Case*, January 2015.

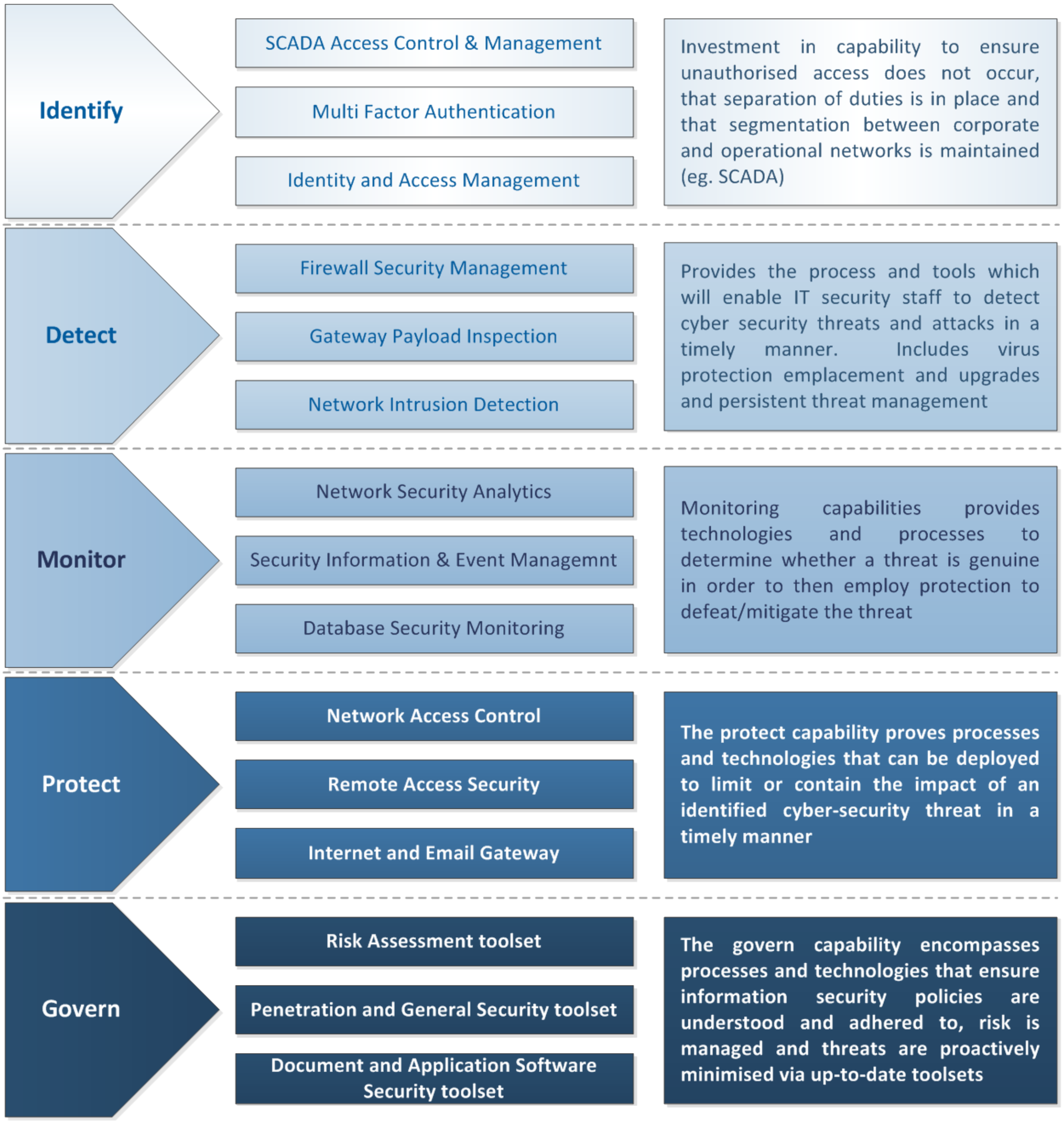
Investment in ensuring unauthorised access is prevented and the capability to detect cyber security threats in a timely manner is a prudent and critical to ensuring energy network protection. Monitoring threats to determine the actions required and deploying protection capabilities to contain the impact of identified threats are fundamental capabilities required to protect Powercor's energy networks. Investment in the toolsets and processes to effectively govern information security ensures robust and best practice processes are in place.

The implementation of the initiatives within each capability will address the mounting security risks facing Powercor, including the heightened risk and incidence of cyber terrorism attacks on critical infrastructure, including:

- enhancements to authentication and identify access management through introduction of multi factor authentication;
- enhancements to detection systems for network intrusion and persistent threats, including to the firewall, as well as improved virus protection and decryption;
- introduction of an internal centre of excellence to monitor and minimise risk;
- improvements to protect unauthorised devices accessing the network including remote access; and
- enhanced security associated with cloud based services, application software development, documents and other systems.

Further explanation of these initiatives is described in figure 7.17.

Figure 7.17 Security capability mapping



Source: Powercor

The underlying principle of these initiatives is that no network is 100% secure, and resilience and planning for incidents is the most successful strategy for maintaining operations and reducing the impacts of breaches.

These initiatives help to ensure that regulatory and compliance requirements are met, such as by complying with standard ISO27002. These capabilities generally reflect the US National Institute of Standards and Technology (**NIST**) Cyber-Security Framework structure, with specific governance items for the local Australian regulatory context. The initiatives will also ensure that incidents are addressed quickly to protect customers' power supply and privacy.

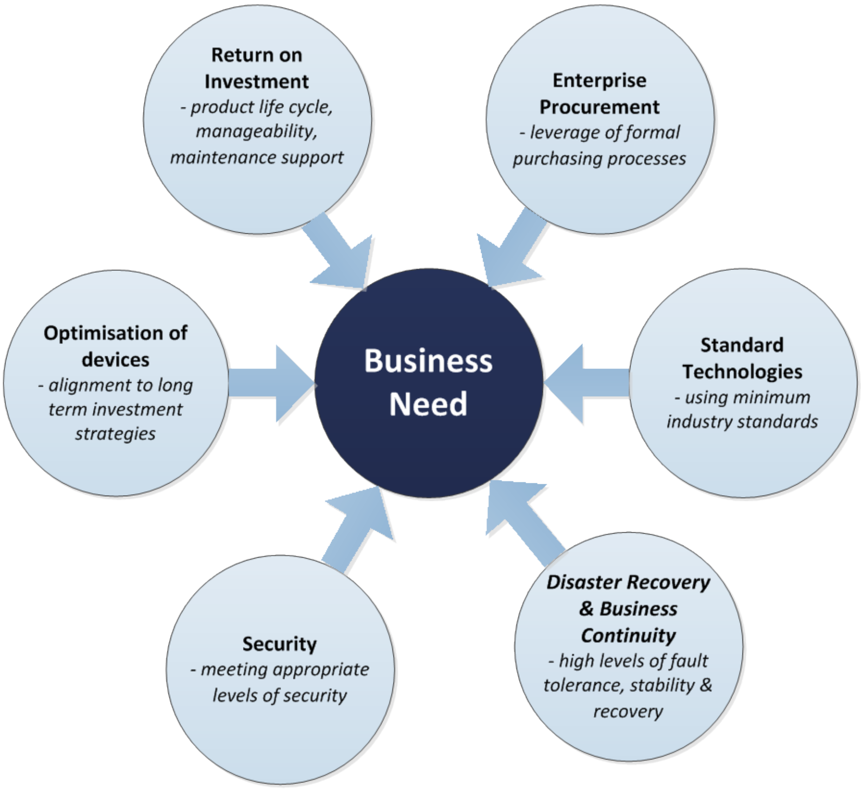
The security expenditure is also reflective of scale of security required to meet the increased access by customers to customer data; the increased information flows from and to mobile devices and the increased number of devices connected to Powercor's networks.

7.4.7 Device replacement

The device replacement stream's goal is to optimise the investment in end user devices to enable workforce productivity whilst optimising cost and performance and taking advantage of technology improvements at an appropriate time. Investment in refreshing the end user devices maintains employee and workforce productivity and performance as the gateway to all corporate systems.

A number of strategic principles influence device replacement decisions, including long term planning for business needs, rather than individual; overall business consideration alongside technology considerations; enterprise procurement practices that drive lower cost solutions; and the adoption of uniformed technology standards to deliver best practice such as standard image, standard device, support and maintenance approaches.

Figure 7.18 Strategic device replacement considerations



Source: Powercor

The scope of the device replacement stream includes all end user devices (**EUDs**) and Human Machine Interfaces (**HMI**'s), incorporating workstations, desktops, notebooks, printers and plotters as follows:

- **Desktops-**optimising the replacement cycle of desktops and associated equipment to balance performance, reliability and cost. This will be achieved by reducing the number of desktops to move the user to device ratio closer to 1:1, as well as using bulk purchasing procurement processes to lower costs;

- **Notebooks-**optimising the replacement cycle of notebooks and associated equipment to balance performance, reliability and cost. This will be achieved by reducing the number of laptops as a result of the increased use of mobility devices, as well as the use of bulk purchasing procurement processes to lower costs;
- **Printers-**optimising the replacement cycle of printers to balance performance, reliability and cost. Bulk procurement processes will be used to achieve a competitive price point;
- **Plotters-**optimising the replacement cycle of plotters to balance performance, reliability and cost. Bulk procurement processes will be used to achieve a competitive price point; and
- **Workstations-**optimising the replacement cycle of occupation specific workstations such as Control Room Operators to balance performance, reliability and cost. Replacement of specialist occupation specific workstations will be undertaken in accordance with the replacement cycle with individual business requirements defining the specification and performance levels required to be achieved (e.g. control room workstations running the Distribution Management System (**DMS**)/Outage Management Systems (**OMS**) and SCADA).

It should be noted that mobility devices, including iPhones and iPads, are not included in this capital expenditure category as they will be treated as operating expenditure going forward – refer appendix G.

8 Non-network

> Non-network expenditure is necessary to support the operation of the network, for example, by having the Elevated Work Platforms or 'cherry-pickers' available and in good working order so that Powercor's crews are able to use them to help restore service to customers quickly in the event of an outage.

This section discusses Powercor's historical and forecast non-network expenditure as well as the approach used in calculating the forecast expenditure.

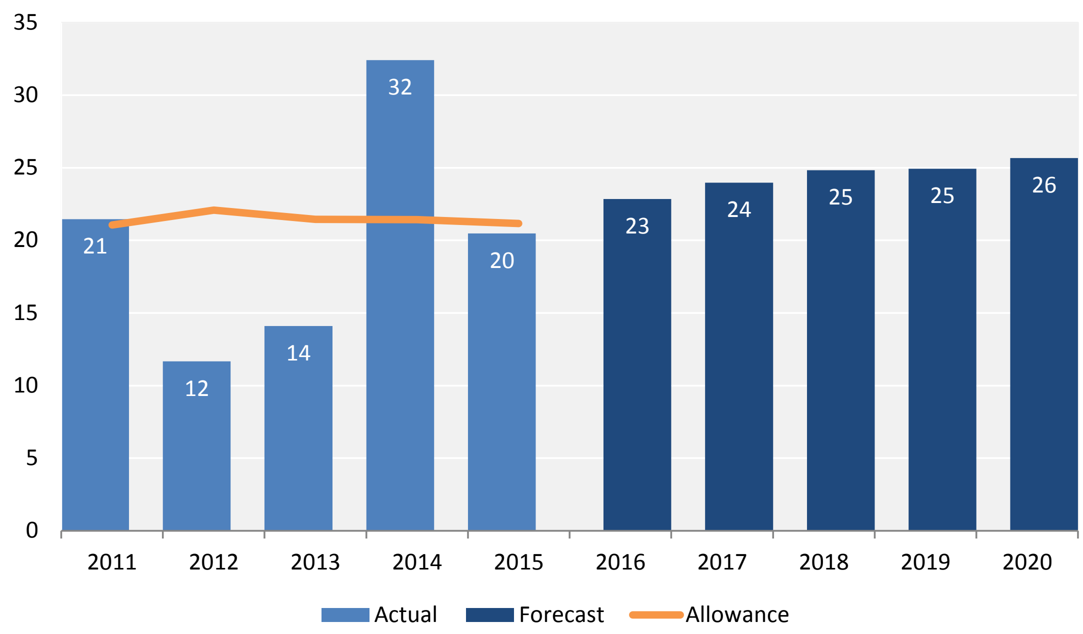
8.1 Overview

Powercor's non-network capital expenditure includes the following cost categories:

- motor vehicles-relates to the purchase, replacement or rebuild costs associated with its light and heavy fleet of vehicles;
- property-relates to the provision of office and depot accommodation, buildings and property;
- supervisory control and data acquisition (**SCADA**): relates to the costs for SCADA and associated network communication and control equipment that are used to monitor and control the distribution network assets, including zone substations and feeders;
- other-includes equity raising costs, general equipment such as miscellaneous tools and equipment.

Figure 8.1 provides an overview of historical and forecast non-network expenditure.

Figure 8.1 Non-network direct capital expenditure ($ million, 2015)[128]



Source: Powercor
Note: excludes equity raising costs

[128] 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

8.2 Background

This section describes the drivers and methodology for forecasting non-network capital expenditure.

8.2.1 Key drivers

Non-network capital expenditure is driven by a range of factors, which are discussed below.

Motor vehicles

The fleet comprises light or passenger fleet such as cars and utility vehicles, as well as heavy or commercial fleet, for example, cranes, elevated working platforms, trailers, crane borer and fork lifts. Powercor's fleet expenditure is driven by:

- replacement cycle and condition of existing motor vehicles;
- new fleet associated with employee growth or network-related programs of work; and
- compliance with legislation and standards as they apply to varying categories of fleet.

Property

Property costs are driven by the need to maintain, refurbish or build new office and depot accommodation, buildings and property.

This expenditure category excludes zone substations, distribution substations and easement costs, where capital costs for those assets is captured in the augmentation or replacement categories.

SCADA

To continue to facilitate and maintain the protection and control of the network, further investment in SCADA is required to deploy communication infrastructure and up to date technology to:

- address technical obsolescence;
- address new requirements; and
- ensure compliance with relevant standards.

The SCADA category captures field devices such as remote control switches and Ethernet communications devices, as well as the fibre optic cable to provide protection signalling and connect field devices with the control room. The IT expenditure category includes costs of field based network communications systems, with the demarcation between SCADA and IT costs occurring at the SCADA front end processor.

Other

These costs relate to the costs of raising equity financing, and other non-network capital expenditure such as general equipment.

8.2.2 Forecasting methodology

The forecasting methodology for each category of non-network expenditure is set out below.

Motor vehicles, property and other

Powercor considers that the use of the historical average expenditure from 2011 to 2014 is appropriate for these small categories of expenditure. While there can be year-on-year variability, taking the average over a period of four years smooths out the impact of the peaks and troughs.

SCADA

SCADA expenditure has been forecast using a bottom-up build of requirements. This forecasting methodology is consistent with other categories of network-related expenditure, and takes into account the changing communication technologies and equipment, and the capability required by the network now and for the future.

The costs for SCADA related projects have been based on actual historical costs for similar projects, where materials, contract labour and services were sourced via competitive tendering processes undertaken periodically. The actual historical costs are reflective of risks and uncertainty that were borne in undertaking the projects.

Equity raising costs

These costs have been forecast using the methodology set out in the AER's Post Tax Revenue Model (**PTRM**).

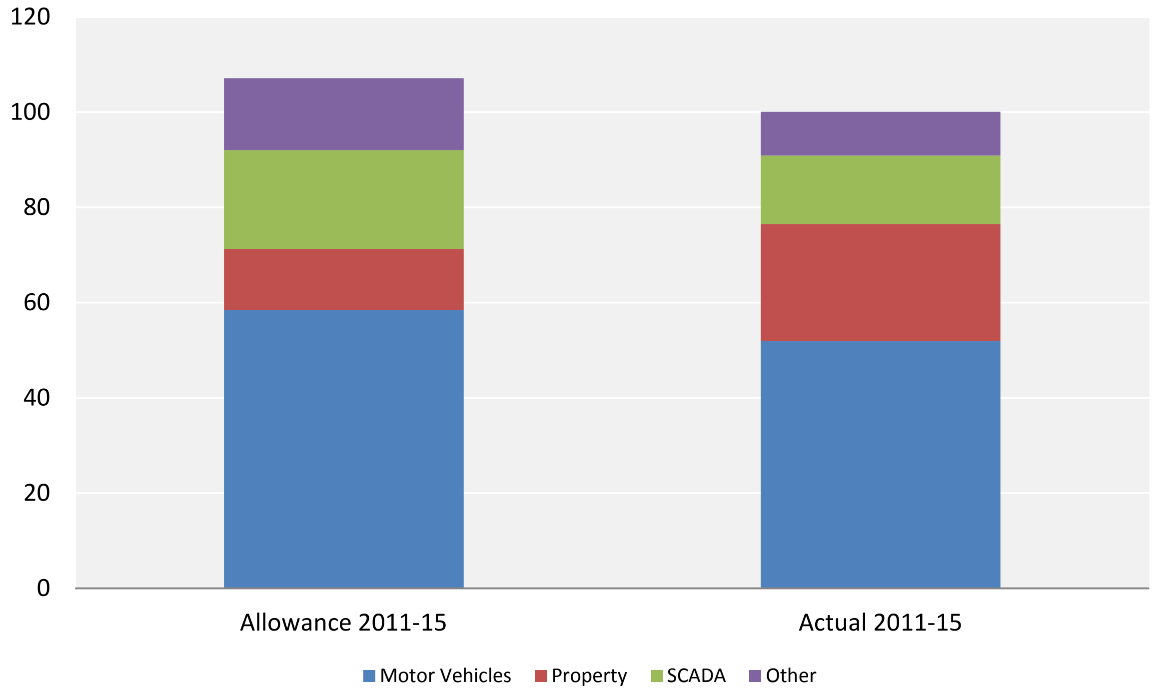
8.3 Historic spend

In the 2011–2015 regulatory control period, Powercor has undertaken a range of activities including:

- replacement of motor vehicles in accordance with the replacement cycle as well as the purchase of new fleet including a crane borer and 13 elevated work platforms to support operational requirements;
- upgrade of the fleet to address changes in safety and compliance as required by Australian Standards (**AS**) or Australian Design Rules (**ADR**), including:
  - mobile cranes were upgraded to be compliant with AS1418;
  - Elevated Work Platforms continue to be upgraded to be compliant with AS2550;
  - anti-locking braking systems (**ABS**) are being installed in trailers over 4.5 tonnes, in accordance with ADR38/04;
  - trucks continue to be upgraded to meet the change in ADR80/04 to reflect Euro 6 for emissions by 2017;
- commencement of the migration of switch control for Automatic Circuit Reclosers away from legacy technology and onto the SCADA Distributed Network Protocol so that Powercor is able to communicate with specific control devices in fire prone areas, with 352 of the 515 sites converted;
- deployment of Ethernet technology into 23 zone substations as part of the strategy to replace unsupported communications technologies in the SCADA network;
- further deployment of fibre infrastructure across the network, as well as sharing fibre infrastructure with other Victorian distributors or entering shared use agreements with fibre optic cable owners in particular cases; and
- refurbishment of the Warrnambool and Echuca depots as well as the Market Street head office plus starting the construction of a new depot in Mildura.

Overall, Powercor is forecast to underspend its non-network expenditure regulatory allowance in the 2011–2015 regulatory period by 7 per cent. This is shown in figure 8.2.

Figure 8.2 Powercor non-network direct capital expenditure ($ million, 2015)



Source: Powercor

While Powercor will overspend its overall non-network expenditure allowance, this consists of underspends and overspends in the categories.

In the largest category of motor vehicles, Powercor will underspend its allowance by around 11 per cent. The expenditure profile for motor vehicles was uneven, reflecting the different number of vehicles purchased or replaced in a given year, as well as expenditure to address changes in safety and compliance.

The second largest category by actual expenditure was property, where Powercor overspent the AER allowance by 91 per cent. The AER allowance is based on the average of expenditure from 2006 to 2009 in accordance with Powercor's proposal, with some small projects over and above that average. However, Powercor undertook some larger projects during the current regulatory period which were noted above.

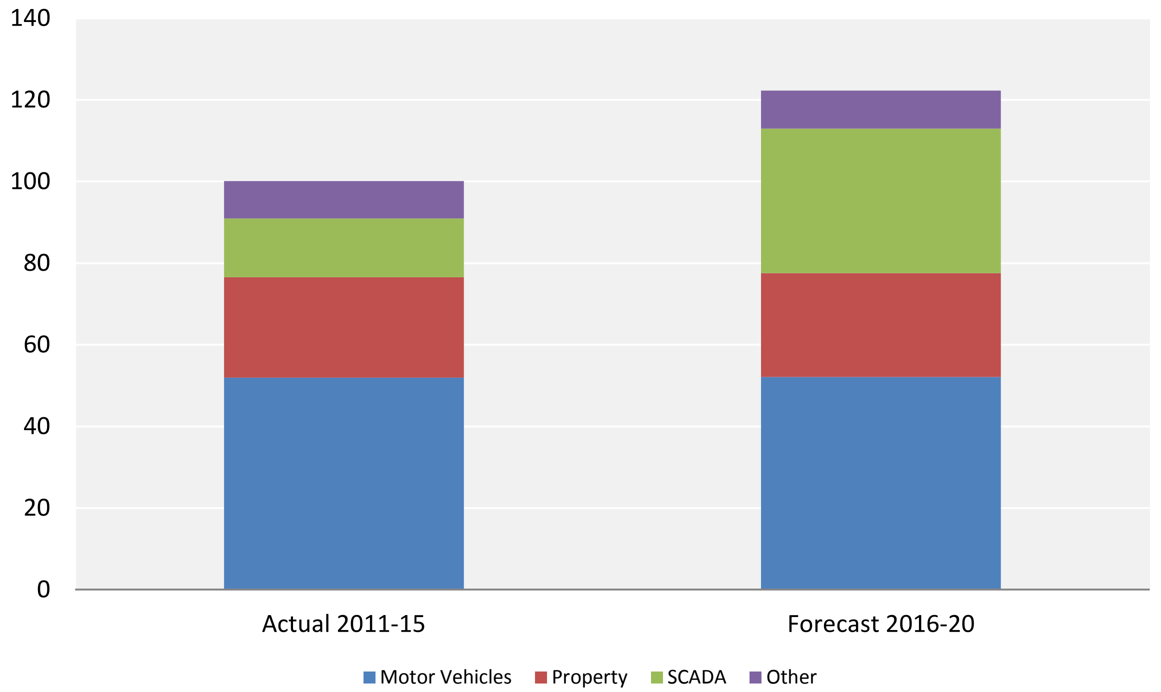
For SCADA, Powercor underspent the AER allowance by 30 per cent as a result of:

- sharing fibre infrastructure with other Victorian distributors in cases where protection equipment crossed distributor boundaries, as well as entering into a negotiated shared use agreement with other fibre optic cable owners rather than building its own fibre in isolated cases;
- plans for expansion of the distribution remote monitoring and control program was reduced following the requirement to deploy remote control SWER ACR; and
- a reduction in field based trials occurred in response to the Smart Grid/Smart City trials given that there was an industry requirement for the trial data and findings to be made available.

8.4 Forecast spend

Powercor requires a 22 per cent increase in non-network capital expenditure compared to its actual expenditure during the 2011–2015 regulatory control period. This is shown in figure 8.3.

Figure 8.3 Powercor non-network direct capital expenditure ($ million, 2015)



Source: Powercor
Note: excludes equity raising costs

The main driver of the forecast expenditure compared to the 2011–2015 regulatory control period is the need to undertake a large project to deploy sophisticated and granular voltage control equipment in the SCADA network at zone substations and on distribution feeders to manage voltage compliance as further small scale embedded generation continues to be connected to the network.

The forecasts are discussed by category below.

Motor vehicles

Powercor's motor vehicle forecast for each year in the 2016–2020 regulatory control period reflects the average of costs incurred from 2011 to 2014. This expenditure will allow Powercor to acquire, replace or rebuild its light and heavy fleet of vehicles and comply with the changes in safety and compliance obligations.

Powercor purchases, rather than leases, motor vehicles. This has been determined this to be most efficient method of sourcing vehicles following an internal review of the procurement strategy.

Powercor will continue to replace its fleet in accordance with its motor vehicle replacement policy shown in table 8.1, which is drawn from its *Transport Policy Manual*. This reflects a combination of legislative requirements, manufacturers' recommendations, improvements in occupational health and safety practices and industry best practice standards. The policy has been reviewed with the replacement cycle changing from 15 years to ten years for Elevated Work Platforms.

Table 8.1 Replacement cycle for motor vehicles

Vehicle	Replacement cycle
Executive Vehicles	4 years or 100,000 kms
Sedan, Station Wagons and Utilities	4 years or 120,000 kms
Vans	6 years or 140,000 kms
Four Wheel Drive – Four Cylinder	6 years or 150,000 kms
Four Wheel Drive – Six Cylinder	6 years or 200,000 kms
Four Wheel Drive – Eight Cylinder	6 years or 300,000 kms
Line construction trucks GLTs	8 years or 250,000 kms
Line construction trucks MCTs	10 years or 300,000 kms
Speciality Vehicles such as Task Trucks	*15 years or 300,000 kms
Speciality Vehicles such as Crane Borers	*10 years or 300,000 kms, replace cab chasses, complete replacement after 20 years
Speciality Vehicles Elevating Platforms	*10 year rebuild to AS2550.10, complete replacement at 15 years
Fork Lifts	10 years
Trailers	15 years
Speciality Plant, Self Loading trailers, cable recovery units	20 years

Source: CitiPower and Powercor, *Transport Policy and Procedure Manual*, 14 April 2009, p. 24.

The forecast expenditure will also allow Powercor to complete its upgrade of Elevated Work Platforms, trailers and trucks.

Property

Powercor's property forecast for each year in the 2016–2020 regulatory control period reflects the average of costs incurred from 2011 to 2014. While Powercor undertook some large projects in the 2011 to 2014 period, some further large projects are also planned including:

- completion of the build of a new depot in Mildura, as the current depot site does not meet the current needs for employees, fleet and storage;
- refurbishment of the Shepparton and Geelong depots; and
- expansion of the yard and operations at the Colac depot as well as expansion of the Ardeer depot.

SCADA

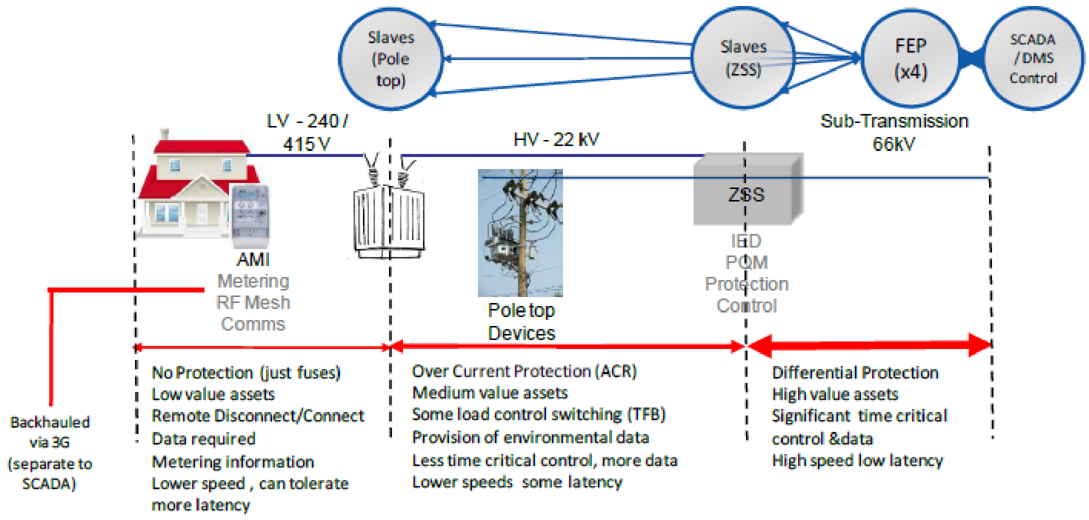
Powercor has undertaken a bottom-up build of its forecasts for SCADA and network control equipment for the 2016–2020 regulatory control period.

The expenditure forecasts have been informed by Powercor's strategy to develop its network communications over the longer term. UXC Consulting undertook a review of the methods and processes used by Powercor in 2012 and developed a strategy for the best way forward to develop the communications network over the longer term. The review found, among other things, that:[129]

- Powercor currently uses a significant amount of older communications technology, mainly due to the many electrical control points configured to use old proprietary bit rate limited SCADA protocols transmitted on voice frequency (**VF**) systems rather than more modern transport systems; and
- other elements within the communications network, specifically microwave and point to multipoint radio that are using VF to transmit data will need to be upgraded to enable support of SCADA Distributed Network Protocol (Level 3) (**DNP3.0**).

Figure 8.4 provides a diagrammatic view of the distribution network, including links for protection and SCADA in 2012. Powercor uses a range of media to communicate between the control room and the remote terminal units in the field including optical fibre, 2G to 3G mobile networks, frame relay/digital subscriber line (**DSL**) fixed line services, digital and analogue radio networks, and VF over State Mobile Radio (**SMR**) and analogue supervisory cable.

Figure 8.4 Current network communications infrastructure



Source: UXC Consulting, *Distribution Network Communications Strategy CitiPower– Powercor*, December 2012, p. 17

In its *Distribution Network Communications Strategy CitiPower – Powercor* report, UXC Consulting recommended:[130]

- continued improvement of the capability and reach of the electrical communications network, with the aim of better management of power control and monitoring devices throughout the electrical network and also support for the introduction of Distribution Automation. This will mean that Powercor will be able to more effectively manage electrical load, especially during peak demand, and during major storm related outage events;
- enable communications to specific control devices (ACRs) within fire prone areas, to enable remote and dynamic changing of ACRs to suit prevailing weather conditions to more effectively meet VBRC recommendations;

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129 UXC Consulting, *Distribution Network Communications Strategy CitiPower– Powercor*, December 2012, pp. 1-2.

130 UXC Consulting, *Distribution Network Communications Strategy CitiPower– Powercor*, December 2012, p. 2.

- upgrade all communications systems to Ethernet interfaces throughout the electrical communications network;
- apply a formal framework that will establish relevant communication requirements for device type, function and location, and enable Powercor to choose the most suitable communications system for establishing an Ethernet connection; and
- expect communications terminal devices used in the field to need to be replaced approximately every five to ten years, that have an ability to interface with Ethernet.

As a result, Powercor's expenditure forecast for SCADA is based on the ongoing move to Ethernet technology and replacing the unsupported technologies such as analogue radio networks and analogue supervisory cable systems over the 2016–2020 regulatory control period.

The strategy report also identified that over the next ten years, Powercor should target more effective network management by using a range of tools including demand management/ load control through Distribution Automation, dynamic load ratings to reduce electricity losses and to implement voltage and Var control.

Distribution Automation refers to the introduction of smart monitoring and control devices in the distribution network to allow the operational and planning teams to better manage energy flows and voltage levels in the network.

In terms of voltage and Var control, Powercor engaged Aecom to undertake a study of the impact of solar PV cell installation on the HV network for urban, rural short and rural long feeders. Using a sample of feeders, Aecom calculated the voltage fluctuation along the distance of the feeder at different levels of load and PV penetration. The voltage model of these determined the extent to which voltage regulation facilities need to be improved and at what tipping points of PV penetration that a change in voltage management is required. Based on this analysis, Aecom recommended that:[131]

- due to the occurrence of reverse power the distribution regulators are to be upgraded to bidirectional, mostly at rural long feeders; and
- where solar penetration is greater than 15 per cent, bidirectional regulators are required at zone substations with a mix of rural long and other feeders and three bidirectional regulators are needed to sectionalise rural long feeders; and
- 89 bidirectional regulators are required on the network, of these, 67 will replace existing unidirectional regulators, and 27 will be new installations.

The implementation of the bidirectional regulators to manage reverse power flow arising from solar PV will enable greater embedded generation onto the Powercor network. This is because without installing the equipment, the reverse power flow on the feeders arising from solar PV will result in voltage levels that are outside of the allowable Victorian Electricity Distribution Code limits, and this would prevent Powercor from allowing additional customers to connect embedded generation to the network. Therefore, the bidirectional regulators will be installed in targeted areas of the network where PV penetration levels are, or are anticipated to, increase and result in voltage level concerns.

[131] Aecom, *Solar PV impact study – strategy recommendations,* 15 October 2014, p. i.

Other

Powercor's forecast for general equipment and other costs for each year in the 2016–2020 regulatory control period reflects the average of costs incurred from 2011 to 2014. The exception to this is equity raising costs, which have been forecast using the methodology set out in the AER's PTRM.

8.5 Programs and projects

Table 8.2 provides an overview of the large programs of work over $2 million that Powercor intends to undertake during the 2016-2020 regulatory control period on non-network projects.

Table 8.2 Network service material projects for non-network capital expenditure

Project name	Description	Cost ($ million, 2015)	Material project no.
Voltage variation	Installation of 89 bidirectional regulators	15.7	AUG 37

Source: Powercor

Note: direct costs excluding real escalation

The only material project in the non-network expenditure category is for the installation of 89 bidirectional regulators to manage voltage variations as a result of the penetration of solar PV. As discussed above, this project will enable further embedded generation into the network.

9 Interaction between capital and operating expenditure forecasts

In developing the regulatory proposal, Powercor has considered the relative costs, benefits, and risk characteristics of the various options to deliver standard control services. The preferred options, be they capital or operating in nature, are the most prudent and efficient of the alternatives available.

Further, where capital expenditure solutions have been selected, Powercor has considered the operating expenditure implications and addressed these in the operating expenditure forecasts.

The capital expenditure for network-related programs for the 2016–2020 regulatory control period involves the addition of new assets on the network. While Powercor will incur higher operating costs to maintain the larger network, this is reflected through the output growth escalation applied to the base year of operating expenditure. This is discussed in the operating expenditure chapter of the regulatory proposal.

The capital and operating expenditure interactions shown in table 9.1 are incremental to the output growth applied, as the step changes are not directly related to an increase in output.

Table 9.1 Interactions between capital and operating expenditure ($ millions, 2015)

		2016	2017	2018	2019	2020	TOTAL
New billing and CRM system	Capex	15.49	11.71				27.21
	Opex			1.73	1.73	1.73	5.20
Mobility	Capex	-	-	-	-	-	0.00
	Opex	0.97	0.44	1.08	0.51	1.16	4.15

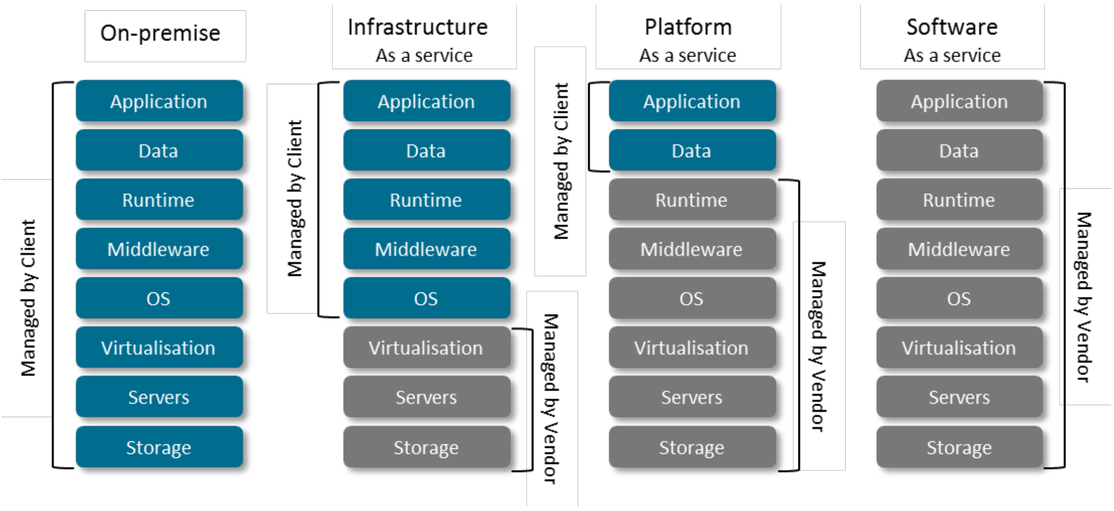
Source: Powercor

Note: direct costs excluding real escalation

The two interactions are described in more detail below.

Firstly, as discussed in the IT chapter, Powercor requires a new billing and CRM system. Following the Capgemini review of product offerings and costings from the market, Powercor proposes to utilise a cloud-based solution for the CRM platform. A cloud-based solution involves a third-party vendor hosting all aspects of the service, rather than an on-premise solution where Powercor purchases and maintains the hardware and software. The different responsibilities between and on-premise and cloud basis solution are shown in figure 9.1.

Figure 9.1 Division of responsibilities for hosting options



Source: Capgemini, *CRM and Billing Market Scan – Final Report*, 27 June 2014, p. 16.

The cloud solution involves Powercor paying a subscription fee to the third-party vendor for the use, support and maintenance of the service. This fee is an operating expenditure payment. As Powercor does not currently have a CRM system, this results in a step-up in expenditure.

Secondly, Powercor's existing approach for accounting for devices such as smart phones and tablets, is a mixture of capital and operating expenditure. However, an internal review has indicated that moving to an operating expenditure only model will be more efficient. The step change, therefore, reflects the efficient substitution of capital expenditure for an operating expenditure solution.